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

FORM 10-K

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

For the fiscal year ended December 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: 001-33303

TARGA RESOURCES PARTNERS LP

(Exact name of registrant as specified in its charter)

Delaware	**65-1295427**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
811 Louisiana Street, Suite 2100, Houston, Texas	**77002**
(Address of principal executive offices)	**(Zip Code)**

(713) 584-1000
(Registrant's telephone number, including area code)

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
9.0% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units	NGLS/PA	New York Stock Exchange

Securities registered pursuant to section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☑

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, 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 ☑

As of February 17, 2020, there were 5,000,000 9.0% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None

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CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Targa Resources Partners LP's (together with its subsidiaries, "we," "us," "our," "TRP" or the "Partnership") 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 level and success of crude oil and natural gas drilling around our assets, our success in connecting natural gas supplies to our gathering and processing systems, oil supplies to our gathering systems and natural gas liquid supplies to our logistics and transportation facilities and our success in connecting our facilities to transportation services and markets;
- 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;
- our ability to access the capital markets, which will depend on general market conditions and the credit ratings for our debt obligations and demand for our senior notes;
- 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 timely obtain and maintain necessary licenses, permits and other approvals;
- our ability to grow through internal growth projects or acquisitions and the successful integration and future performance of such assets;
- general economic, market and business conditions; and
- the risks described elsewhere in "Item 1A. Risk Factors" in this 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 Annual 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 "Item 1A. Risk Factors" in this 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 Annual 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
VLGC	Very large gas carrier

PART I

Item 1. Business.

Overview

Targa Resources Partners LP is a Delaware limited partnership formed in October 2006 by our parent, Targa Resources Corp. ("Targa" or "TRC" or the "Company" or "Parent"), to own, operate, acquire and develop a diversified portfolio of complementary domestic midstream energy assets.

On February 17, 2016, TRC completed the previously announced transactions contemplated by the Agreement and Plan of Merger (the "TRC/TRP Merger Agreement"), by and among us, Targa Resources GP LLC (our "general partner"), TRC and Spartan Merger Sub LLC, a subsidiary of TRC ("Merger Sub") pursuant to which TRC acquired indirectly all of our outstanding common units that TRC and its subsidiaries did not already own. Upon the terms and conditions set forth in the Merger Agreement, Merger Sub merged with and into TRP (the "TRC/TRP Merger"), with TRP continuing as the surviving entity and as a subsidiary of TRC. As a result of the TRC/TRP Merger, TRC owns all of our outstanding common units.

Pursuant to the TRC/TRP Merger Agreement, TRC has agreed to cause our common units to be delisted from the New York Stock Exchange ("NYSE") and deregistered under the Securities Exchange Act of 1934, as amended (the "Exchange Act"). As a result of the completion of the TRC/TRP Merger, our common units are no longer publicly traded. Our 9.00% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Preferred Units") that were issued in October 2015 remain outstanding as limited partner interests in us and continue to trade on the NYSE under the symbol "NGLS PRA."

As used herein, "units" refers to our units representing limited partner interests in the Partnership and not to the Preferred Units (as defined herein) and "unitholders" refers to the holders of units. Unless the context requires otherwise, the term "limited partner interests" refers to the units and the Preferred Units, collectively, and "limited partners" refers to the holders of limited partner interests.

The following should be read in conjunction with our audited consolidated financial statements and the notes thereto. We have prepared our accompanying consolidated financial statements under GAAP and the rules and regulations of the SEC. Our accounting records are maintained in U.S. dollars and all references to dollars in this report are to U.S. dollars, except where stated otherwise. Our consolidated financial statements include our accounts and those of our majority-owned and/or controlled subsidiaries, and all significant intercompany items have been eliminated in consolidation. The address of our principal executive offices is 811 Louisiana Street, Suite 2100, Houston, Texas 77002, and our telephone number at this address is (713) 584-1000.

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 Transportation (also referred to as the Downstream Business).

In the fourth quarter of 2019, we made the following changes to the presentation of our reportable segments:

- Renamed the Logistics and Marketing segment as "Logistics and Transportation." The updated name better describes the business composition and activity of the segment given the recent completion of our common carrier Grand Prix Pipeline ("Grand Prix") that transports NGLs to our fractionation assets in Mont Belvieu. The change in naming convention did not impact previously reported results for the segment. This segment is also referred to as the Downstream Business.

- Due to changes in how our executive team evaluates segment performance, results of commodity derivative activities related to our equity volume hedges that are designated as accounting hedges are now reported in the Gathering and Processing segment. These hedge activities were previously reported in Other. Our prior period segment information has been updated to reflect the change. There was no impact to our Consolidated Statements of Operations.

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, Central 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 (including the Bakken and Three Forks plays); and the onshore and near offshore regions of the Louisiana Gulf Coast and the Gulf of Mexico.

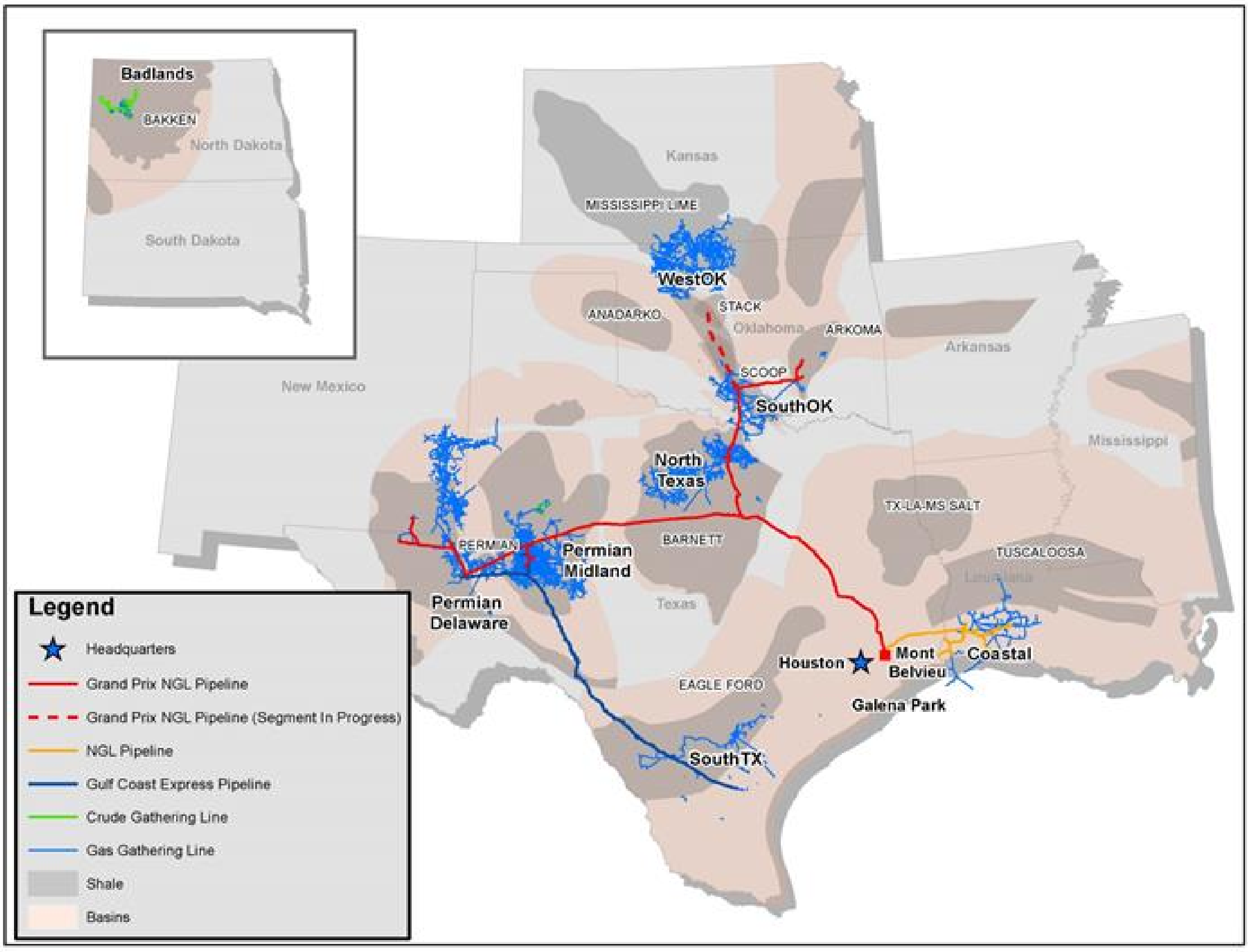
Our Logistics and Transportation segment includes the activities and assets necessary to convert mixed NGLs into NGL products and also includes other assets and value-added services such as transporting, storing, fractionating, terminaling and marketing of NGLs and NGL products, including services to LPG exporters and certain natural gas supply and marketing activities in support of our other businesses. The Logistics and Transportation segment also includes Grand Prix, as well as our equity interest in Gulf Coast Express Pipeline LLC ("GCX"), a natural gas pipeline transporting volumes from West Texas to the Gulf Coast. Grand Prix integrates 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 pipelines, are generally connected to and supplied in part by our Gathering and Processing segment and, except for the pipelines and smaller terminals, are located predominantly in Mont Belvieu and Galena Park, Texas, and in Lake Charles, Louisiana.

Acquisitions and Organic Growth Projects

Our midstream natural gas and NGL services footprint was initially established through several acquisitions from Targa, totaling $3.1 billion, that occurred from 2007 through 2010. Since the completion of the final acquisitions from Targa in 2010, we have expanded our midstream services footprint substantially. The expansion of our business has been fueled by a combination of third-party acquisitions and major organic growth investments in our businesses. Third-party acquisitions included our 2012 acquisition of Saddle Butte Pipeline LLC's crude oil pipeline and terminal system and natural gas gathering and processing operations in North Dakota (referred to by us as "Badlands"), our 2015 acquisition of Atlas Pipeline Partners L.P. ("APL," renamed by us as Targa Pipeline Partners LP or "TPL"), and our 2017 acquisition of gas gathering and processing and crude oil gathering assets in the Permian Basin (referred to by us as the "Permian Acquisition"). As a result of these transactions, we acquired natural gas gathering, processing and treating assets in West Texas, South Texas, North Texas, Oklahoma, North Dakota, New Mexico and the Louisiana Gulf Coast, crude oil gathering and terminal assets in North Dakota and West Texas, and NGL assets consisting of fractionation, transport, storage and terminaling facilities, low sulfur natural gas treating facilities ("LSNG"), pipeline transportation and distribution assets, propane storage and truck terminals primarily located near Houston, Texas and in Lake Charles, Louisiana.

We also continue to invest capital in our businesses to enhance our competitive advantage as an integrated midstream services provider. We have invested approximately $8.4 billion in growth capital expenditures since 2015, including approximately $2.6 billion in 2019 (approximately $2.3 billion of net growth capital). These expansion investments are distributed across our businesses, with 52% to Gathering and Processing and 48% related to Logistics and Transportation. We expect to continue to invest in both large and small organic growth projects in 2020 and currently estimate that we will invest approximately $1.2 to $1.3 billion in net organic growth capital expenditures in 2020.

The map below highlights our more significant assets:



Recent Developments

Gathering and Processing Segment Expansion

Permian Midland Processing Expansions

In response to increasing production and to meet the infrastructure needs of producers, we have recently completed construction of or are constructing three new 250 MMcf/d cryogenic natural gas processing plants in the Midland Basin. The first plant, the Hopson Plant, began operations in the second quarter of 2019. The second plant, the Pembrook Plant, began operations in the third quarter of 2019. In August 2019, we announced the Gateway Plant, which is expected to begin operations in the fourth quarter of 2020.

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 constructed approximately 220 miles of 12- to 24-inch high-pressure rich gas gathering pipelines across the Delaware Basin that are operational. We have recently completed construction of or are currently constructing two new 250 MMcf/d cryogenic natural gas processing plants in the Delaware Basin. The first plant, the Falcon Plant, began operations late in the third quarter of 2019. The second plant, the Peregrine

Plant, 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.

Badlands

In January 2018, we announced the formation of a 50/50 joint venture with Hess Midstream Partners LP under which Targa would construct and operate a new 200 MMcf/d natural gas processing plant ("LM4 Plant") at Targa's existing Little Missouri facility. The LM4 Plant began operations in the third quarter of 2019.

Logistics and Transportation Segment Expansion

Grand Prix NGL Pipeline

In the third quarter of 2019, we began full service into Mont Belvieu on Grand Prix, our new common carrier NGL pipeline that transports NGLs from the Permian Basin, North Texas, and Southern Oklahoma to our fractionation and storage complex in the NGL market hub at Mont Belvieu, Texas. The pipeline is comprised of three primary segments:

- Permian Basin Segment – Connects our Gathering and Processing positions (as well as third-party 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.

- Southern Oklahoma Extension – Connects our SouthOK and North Texas Gathering and Processing positions (as well as third-party positions) to our North Texas to Mont Belvieu Segment. The extension varies 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 connects Permian, North Texas and Oklahoma volumes to Mont Belvieu. The North Texas to Mont Belvieu Segment has a capacity of approximately 450 MBbl/d, expandable to 950 MBbl/d.

In February 2019, we announced an additional extension:

- 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. The Central Oklahoma Extension is expected to be completed in the first quarter of 2021.

Grand Prix Pipeline LLC ("Grand Prix Joint Venture"), a consolidated subsidiary of which Targa owns a 56% interest, owns the portion of Grand Prix extending from the Permian Basin to Mont Belvieu, Texas. Volumes flowing on the pipeline from the Permian Basin to Mont Belvieu, Texas, accrue to the Grand Prix Joint Venture, while the volumes flowing from North Texas and Oklahoma to Mont Belvieu accrue solely to Targa's benefit.

Fractionation Expansion

In February 2018, we announced plans to construct a new 100 MBbl/d fractionation train ("Train 6") in Mont Belvieu, Texas, which began operations in the second quarter of 2019. Targa Train 6 LLC ("Train 6 JV"), a joint venture between Targa and Stonepeak Infrastructure Partners ("Stonepeak"), owns a 100% interest in the fractionation train. Certain fractionation-related infrastructure for Train 6, such as storage caverns and brine handling, were funded and are 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 by the end of the first quarter of 2020 and the end of the third quarter of 2020, respectively. In January 2019, Williams committed to Targa significant volumes which Targa will transport on Grand Prix and fractionate at Targa's Mont Belvieu facilities (including Train 7). Williams was also granted an option to purchase a 20% equity interest in the fractionation train, which was originally wholly owned by Targa. Williams exercised its initial option and executed a joint venture agreement with us in the second quarter of 2019. Certain fractionation-related infrastructure for Train 7, such as 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. With the additional infrastructure, our effective export capacity will increase to up to 15 MMBbl per month, depending upon the mix of propane and butane demand, vessel size and availability of supply, among other factors. The expansion is expected to be fully completed in the third quarter of 2020.

Gulf Coast Express Pipeline

In December 2017, we entered into definitive joint venture agreements to form GCX with Kinder Morgan Texas Pipeline LLC ("KMTP") and DCP Midstream Partners, LP ("DCP") for the purpose of developing 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 provides an outlet for increased natural gas production from the Permian Basin to growing markets along the Texas Gulf Coast. Targa GCX Pipeline LLC ("GCX DevCo JV"), a joint venture between us and Stonepeak, and DCP each own a 25% interest, KMTP owns a 34% interest, and Altus Midstream Company owns the remaining 16% interest in GCX. KMTP serves as the 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, also committed volumes to GCX Pipeline. GCX Pipeline is designed to transport up to 1.98 Bcf/d of natural gas and commenced operations late in the third quarter of 2019.

Badlands Interest Sale

In April 2019, we closed on the sale of a 45% interest in Targa Badlands LLC ("Targa Badlands"), the entity that holds substantially all of the assets previously wholly owned by Targa 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 and hold majority governance rights. Future growth capital of Targa Badlands is expected to be funded on a pro rata ownership basis. Targa Badlands pays 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. Targa Badlands is a discrete entity and the assets and credit of Targa Badlands are not available to satisfy the debts and other obligations of Targa or its other subsidiaries.

Asset Sales

We continue to evaluate and execute asset sales to reduce leverage and focus on our core operations. During 2019, we closed on the sale of an equity-method investment for $73.8 million. In November 2019, we executed agreements to sell our crude gathering and storage business in the Permian Delaware for approximately $134 million. The sale closed early in the first quarter of 2020.

We have also engaged Jefferies LLC to evaluate the potential divestiture of our crude gathering business in the Permian Midland, which includes crude gathering and storage assets. The sale process is ongoing, and the potential divestiture is predicated on third party valuations adequately capturing our forward growth expectations for the assets. No assurance can be made that a sale will be consummated.

Financing Activities

In January 2019, we 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 $1,486.6 million. The net proceeds from the issuance were used to redeem in full our 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 repayment of borrowings under our credit facilities.

In November 2019, we issued $1.0 billion aggregate principal amount of 5½% Senior Notes due March 2030, resulting in net proceeds of $990.8 million. The net proceeds from the issuance were used to repay borrowings under our credit facilities and for general partnership purposes.

On December 6, 2019, we amended our accounts receivable securitization facility (the "Securitization Facility") to extend the facility through a termination date of December 4, 2020.

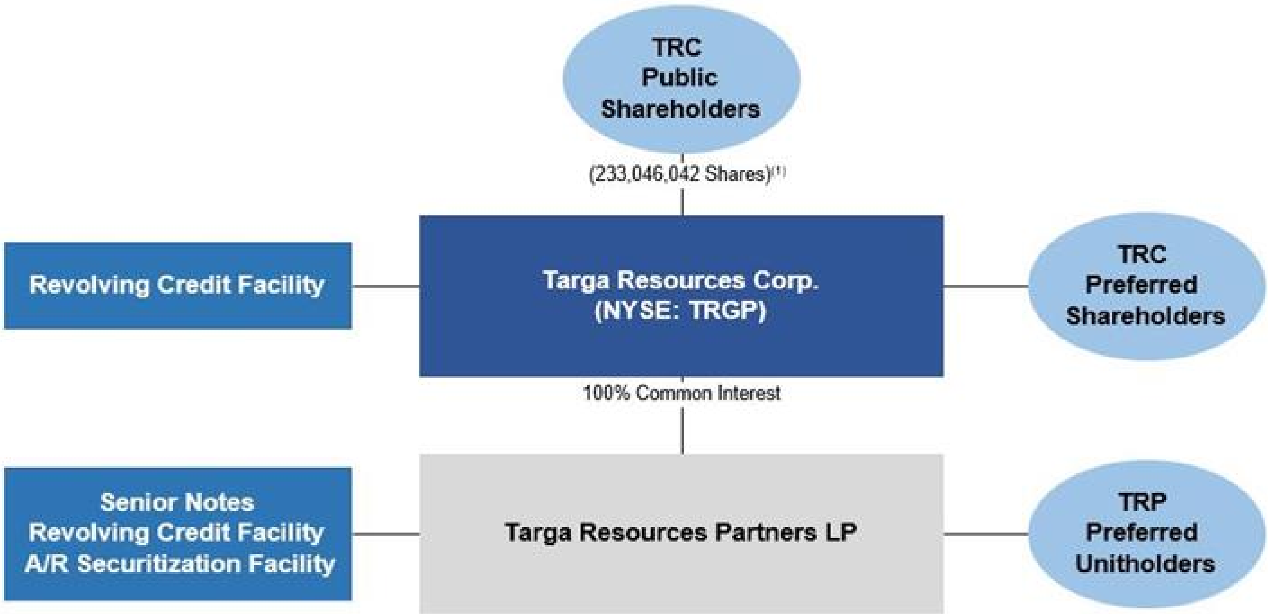
Organization Structure

On October 19, 2016, we executed the Third Amended and Restated Agreement of Limited Partnership, effective as of December 1, 2016. As a result of the TRC/TRP Merger, Targa owns all of the outstanding TRP common units. Targa also maintains a 2% general partner interest in us. The Partnership Agreement with us governs our relationship regarding certain reimbursement and indemnification matters. See "Item 13. Certain Relationships and Related Transactions and Director Independence."

Targa has used us as a growth vehicle to pursue the acquisition and expansion of midstream natural gas, NGL, crude oil and other complementary energy businesses and assets as evidenced by our acquisitions of businesses from Targa. However, Targa is not prohibited from competing with us and may evaluate acquisitions and dispositions that do not involve us. In addition, through our relationship with Targa, we have access to a significant pool of management talent, strong commercial relationships throughout the energy industry and access to Targa's broad operational, commercial, technical, risk management and administrative infrastructure.

We do not have any employees to carry out our operations. Targa charges us for all the direct costs of the employees assigned to our operations, as well as all general and administrative support costs other than its direct support costs of being a separate reporting company and its cost of providing management and support services to certain unaffiliated spun-off entities. We generally reimburse Targa for cost allocations to the extent that they have required a current cash outlay by Targa. See "—Employees" for further information.

The diagram below shows our corporate structure as of February 17, 2020:



(1) Common shares outstanding as of February 17, 2020.

Growth Drivers

We believe that our near-term growth will be driven by organic projects being placed into service, as well as the level of producer activity in the basins where our gathering and processing infrastructure is located and the level of demand for services provided by our logistics and transportation assets. We believe our assets are not easily replicated, are located in many attractive and active areas of exploration and production activity and are near key markets and logistics centers. Grand Prix integrates our gathering and processing positions in the Permian Basin, Southern Oklahoma and North Texas with our downstream facilities in Mont Belvieu, Texas and further increases our competitive capabilities to provide reliable, integrated midstream services to customers. Over the longer term, we expect our growth will continue to be driven by our integrated midstream service offering and the strong position of our quality assets which will benefit from production from shale plays and by the deployment of shale exploration and production technologies in both liquids-rich natural gas and crude oil resource plays that will also provide additional opportunities for our Downstream Business. We expect that organic growth and third-party acquisitions will continue to be a part of our growth strategy.

Attractive Asset Positions

We believe that our positioning in some of the most attractive basins will allow us to capture increased natural gas supplies for gathering and processing, increased NGLs for transportation and fractionation and increased crude oil supplies for gathering and terminaling. Producers continue to focus drilling activity on their most attractive acreage, especially in the Permian Basin where we have a large and well positioned interconnected footprint and are benefiting from rig activity in and around our systems.

The development of shale and unconventional resource plays has resulted in increasing NGL supplies that continue to generate demand for our transportation services on Grand Prix, fractionation services at the Mont Belvieu market hub and for LPG export services at our Galena Park Marine Terminal on the Houston Ship Channel. Since 2010, in response to increasing demand, we added 378 MBbl/d of additional fractionation capacity with the additions of Cedar Bayou Fractionator ("CBF") Trains 3, 4, and 5, and Train 6, and have additional capacity of 220 MBbl/d under construction. We believe that the higher volumes of fractionated NGLs will also result in increased demand for other related fee-based services provided by our logistics and transportation assets. Continued demand for fractionation capacity is expected to lead to other future growth opportunities.

As domestic producers have focused their drilling in crude oil and liquids-rich areas, new gas processing facilities are being built to accommodate liquids-rich gas, which contributes to the increasing supply of NGLs produced domestically. As drilling in these areas continues, the supply of NGLs requiring transportation and fractionation to market hubs is expected to continue to grow. As the supply of NGLs increases, our integrated Mont Belvieu and Galena Park Marine Terminal assets allow us to provide the raw product, fractionation, storage, interconnected terminaling, refrigeration and ship loading capabilities to support exports by third-party customers. Grand Prix transports volumes from the Permian Basin and our North Texas and southern Oklahoma systems to our fractionation and storage complex in the NGL market hub at Mont Belvieu further enhancing the integration of our gathering and processing assets with our logistics and transportation assets. Grand Prix positions us to offer an integrated midstream service across the NGL value chain to our customers by linking supply to key markets.

Drilling and production activity from liquids-rich natural gas shale plays and similar crude oil resource plays

We are actively pursuing natural gas gathering and processing and NGL transportation and fractionation opportunities associated with liquids-rich natural gas from shale and other resource plays and are also actively pursuing crude gathering and natural gas gathering and processing and NGL transportation and fractionation opportunities from active crude oil resource plays. We believe that our leadership position in the Downstream Business, which includes our transportation, fractionation and export services, provides us with a competitive advantage relative to other midstream companies without these capabilities.

Organic growth and third-party acquisitions

We have a demonstrated track record of completing organic growth and third-party acquisitions. Since 2015, we have executed on approximately $8.4 billion of growth capital projects and approximately $6.0 billion in third-party acquisitions. We expect to continue to grow both organically and through third-party acquisitions.

Competitive Strengths and Strategies

We believe that we are well positioned to execute our business strategies due to the following competitive strengths:

Strategically located gathering and processing asset base

Our gathering and processing businesses are strategically located in attractive oil and gas producing basins and are well positioned within each of those basins. Activity in the shale resource plays underlying our gathering assets is driven by the economics of oil, condensate, gas and NGL production from the particular reservoirs in each play. Activity levels for most of our gathering and processing assets are driven by commodity prices, primarily crude oil prices. If drilling and production activities in these areas continue, the volumes of natural gas and crude oil available to our gathering and processing systems will likely increase.

Leading fractionation, LPG export and NGL infrastructure position

We are one of the largest fractionators of NGLs in the Gulf Coast. Our fractionation assets are primarily located in Mont Belvieu, Texas, and to a lesser extent Lake Charles, Louisiana, which are key market centers for NGLs. Our logistics operations at Mont Belvieu, the major U.S. hub of NGL infrastructure, include connections to a number of mixed NGL ("mixed NGLs" or "Y-grade") supply pipelines, storage, interconnection and takeaway pipelines and other transportation infrastructure. Our logistics assets, including fractionation facilities, storage wells, low ethane propane de-ethanizer, and our Galena Park Marine Terminal and related pipeline systems and interconnects, are also located near and connected to key consumers of NGL products including the petrochemical and industrial markets. Grand Prix is one of the Y-grade supply pipelines that connects the very active Permian Basin to Mont Belvieu. The location and interconnectivity of these assets are not easily replicated, and we have additional capability to expand their capacity. We have extensive experience in operating these assets and developing, permitting and constructing new midstream assets.

Comprehensive package of midstream services

We provide a comprehensive package of services to natural gas and crude oil producers. These services are essential to gather, process, treat and transport wellhead gas to meet pipeline standards; extract, transport and fractionate NGLs for sale into petrochemical, industrial, commercial and export markets; and gather crude. We believe that our ability to offer these integrated services provides us with an advantage in competing for new supplies because we can provide substantially all of the services that producers, marketers and others require for moving natural gas, NGLs and crude oil from wellhead to market on a cost-effective basis. Both Grand Prix and the GCX Pipeline further enhance our position to offer an integrated midstream service across the NGL and natural gas value chain by linking supply to key markets. Additionally, we believe that the significant investment we have made to construct and acquire assets in key strategic positions and the expertise we have in operating such assets make us well-positioned to remain a leading provider of comprehensive services in the midstream sector.

High quality and efficient assets

Our gathering and processing systems and logistics and transportation assets consist of high-quality, well-maintained facilities, resulting in low-cost, efficient operations. Advanced technologies have been implemented for processing plants (primarily cryogenic units utilizing centralized control systems), measurement systems (essentially all electronic and electronically linked to a central data-base) and operations and maintenance management systems to manage work orders and implement preventative maintenance schedules (computerized maintenance management systems). These applications have allowed proactive management of our operations resulting in lower costs and minimal downtime. We have established a reputation in the midstream industry as a reliable and cost-effective supplier of services to our customers and have a track record of safe, efficient, and reliable operation of our facilities. We will continue to pursue new contracts, cost efficiencies and operating improvements of our assets. Such improvements in the past have included new production and acreage commitments, reducing fuel gas and flare volumes and improving facility capacity and NGL recoveries. We will also continue to optimize existing plant assets to improve and maximize capacity and throughput.

In addition to routine annual maintenance expenses, our maintenance capital expenditures have averaged approximately $126 million per year over the last three years. We believe that our assets are well-maintained and we are focused on continuing to operate our existing assets, and operating our new assets, in a prudent, safe and cost-effective manner.

Large, diverse business mix with favorable contracts and increasing fee-based business

We maintain gas gathering and processing positions in strategic oil and gas producing areas across multiple basins and provide these and other services under attractive contract terms to a diverse mix of producers across our areas of operation. Consequently, we are not dependent on any one oil and gas basin or counterparty. Our Logistics and Transportation assets are typically located near key market hubs and near most of our NGL customers. They also serve must-run portions of the natural gas and natural gas liquids value chain, are primarily fee-based and have a diverse mix of customers.

Our contract portfolio has attractive rate and term characteristics including a significant fee-based component, especially in our Downstream Business. Our expected continued growth of the fee-based Downstream Business may result in increasing fee-based cash flow. The Permian Acquisition resulted in increased fee-based cash flow as the entities acquired have primarily fee-based gathering and processing contracts. Additionally, the long-term agreements with the investment grade energy company in the Delaware Basin for natural gas gathering and processing services and logistics and transportation services is fee-based. We also have an initiative underway to reduce our commodity price exposure across our gathering and processing business by amending contracts or entering into new contracts with primarily fee-based components and/or protections.

Financial flexibility

We have historically maintained sufficient liquidity and have funded our growth investments with a mix of equity, debt, asset sales and joint ventures over time in order to manage our leverage ratio. Disciplined management of liquidity, leverage and commodity price volatility allow us to be flexible in our long-term growth strategy and enable us to pursue strategic acquisitions and large growth projects.

Experienced and long-term focused management team

Our current executive management team possesses breadth and depth of experience working in the midstream energy business. Many members of our executive management team have been with us since the Partnership was formed in 2006, managed many of our businesses prior to acquisition by Targa, or joined shortly thereafter. Other officers and key employees have significant experience in the industry and with our assets and businesses.

Attractive cash flow characteristics

We believe that our strategy, combined with our high-quality asset portfolio, allows us to generate attractive cash flows. Geographic, business and customer diversity enhances our cash flow profile. Our Gathering and Processing segment contract mix has increasing components of fee-based margin driven by: (i) fees added to percent-of-proceeds contracts for natural gas treating and compression, (ii) new/amended contracts with a combination of percent-of-proceeds and fee-based components, including fee floors, and (iii) essentially fully fee-based crude oil gathering and gas gathering and processing contracts. Contracts in our Coastal Gathering and Processing segment are primarily hybrid contracts (percent-of-liquids with a fee floor) or percent-of-liquids contracts (whereby we receive an agreed upon percentage of the actual proceeds of the NGLs). Contracts in the Downstream Business are predominately fee-based (based on volumes and contracted rates), with a large take-or-pay component. Our contract mix, along with our commodity hedging program, serves to mitigate the impact of commodity price movements on cash flow.

We have hedged the commodity price risk associated with a portion of our expected natural gas, NGL and condensate equity volumes, future commodity purchases and sales, and transportation basis risk by entering into financially settled derivative transactions. These transactions include swaps, futures, purchased puts (or floors) and costless collars. The primary purpose of our commodity risk management activities is to hedge our exposure to price risk and to mitigate the impact of fluctuations in commodity prices on cash flow. We have intentionally tailored our hedges to approximate specific NGL products and to approximate our actual NGL and residue natural gas delivery points. Although the degree of hedging will vary, we intend to continue to manage some of our exposure to commodity prices by entering into similar hedge transactions. We also monitor and manage our inventory levels with a view to mitigate losses related to downward price exposure.

Asset base well-positioned for organic growth

We believe that our asset platform and strategic locations allow us to maintain and potentially grow our volumes and related cash flows as our supply areas benefit from continued exploration and development over time. Technology advances have resulted in increased domestic oil and liquids-rich gas drilling and production activity. The location of our assets provides us with access to natural gas and crude oil supplies and proximity to end-user markets and liquid market hubs while positioning us to capitalize on drilling and production activity in those areas. We believe that as global supply and demand for natural gas, crude oil and NGLs, and services for each grows over the long term, our infrastructure will increase in value as such infrastructure takes on increasing importance in meeting that growing supply and demand.

While we have set forth our strategies and competitive strengths above, our business involves numerous risks and uncertainties which may prevent us from executing our strategies. These risks include the adverse impact of changes in natural gas, NGL and condensate/crude oil prices, the supply of or demand for these commodities, and our inability to access sufficient additional production to replace natural declines in production. For a more complete description of the risks associated with an investment in us, see “Item 1A. Risk Factors.”

Our Business Operations

Our operations are reported in two segments: (i) Gathering and Processing, and (ii) Logistics and Transportation (also referred to as the Downstream Business).

Gathering and Processing Segment

Our Gathering and Processing segment consists of gathering, compressing, dehydrating, treating, conditioning, processing, and marketing natural gas and gathering crude oil. The gathering of natural gas consists of aggregating natural gas produced from various wells through varying diameter gathering lines to processing plants. Natural gas has a widely varying composition depending on the field, the formation and the reservoir from which it is produced. The processing of natural gas consists of the extraction of imbedded NGLs and the removal of water vapor and other contaminants to form (i) a stream of marketable natural gas, commonly referred to as residue gas, and (ii) a stream of mixed NGLs. Once processed, the residue gas is transported to markets through pipelines that are owned by third parties and the GCX Pipeline. End-users of residue gas include large commercial and industrial customers, as well as natural gas and electric utilities serving individual consumers. We sell our residue gas either directly to such end-users or to marketers into intrastate or interstate pipelines, which are typically located in close proximity or with ready access to our facilities. The gathering of crude oil consists of aggregating crude oil production primarily through gathering pipeline systems, which deliver crude oil to a combination of other pipelines, rail and truck.

We continually seek new supplies of natural gas and crude oil, both to offset the natural decline in production from connected wells and to increase throughput volumes. We obtain additional natural gas and crude oil supply in our operating areas by contracting for production from new wells or by capturing existing production currently gathered by others. Competition for new natural gas and crude oil supplies is based primarily on location of assets, commercial terms including pre-existing contracts, service levels and access to markets. The commercial terms of natural gas gathering and processing arrangements and crude oil gathering are driven, in part, by capital costs, which are impacted by the proximity of systems to the supply source and by operating costs, which are impacted by operational efficiencies, facility design and economies of scale.

The Gathering and Processing segment's assets are located in the Permian Basin of West Texas and Southeast New Mexico (including the Midland, Central 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 (including the Bakken and Three Forks plays) and in the onshore and near offshore regions of the Louisiana Gulf Coast and the Gulf of Mexico.

The natural gas processed in this segment is supplied through our gathering systems which, in aggregate, consist of approximately 28,900 miles of natural gas pipelines and include 46 owned and operated processing plants. During 2019, we processed an average of 4,438.2 MMcf/d of natural gas and produced an average of 505.4 MBbl/d of NGLs. In addition to our natural gas gathering and processing, the Badlands operations include a crude oil gathering system and four terminals with crude oil operational storage capacity of 205 MBbl, and our Permian operations include a crude oil gathering system and two terminals with crude oil operational storage capacity of 20 MBbl. In January 2020, we closed on the sale of our crude gathering and storage business in the Permian Delaware, see "—Recent Developments—Asset Sales" above. During 2019, we gathered an aggregate average of 255.9 MBbl/d of crude oil in the Badlands and Permian.

The Gathering and Processing segment's operations consist of Permian Midland, Permian Delaware, SouthTX, North Texas, SouthOK, WestOK, Coastal and Badlands each as described below:

Permian Midland

The Permian Midland system consists of approximately 6,600 miles of natural gas gathering pipelines and fourteen processing plants with an aggregate nameplate capacity of 2,129 MMcf/d, all located within the Permian Basin in West Texas. Ten of these plants and 4,800 miles of gathering pipelines belong to a joint venture ("WestTX"), in which we have an approximate 72.8% ownership. Pioneer, a major producer in the Permian Basin, owns the remaining interest in the WestTX system.

In addition, we are constructing the Gateway Plant, a new 250 MMcf/d cryogenic natural gas processing plant included as part of WestTX in the Midland Basin. The Gateway Plant is expected to begin operations in the fourth quarter of 2020.

Permian Delaware

The Permian Delaware system consists of approximately 5,900 miles of natural gas gathering pipelines and eight processing plants with an aggregate capacity of 1,050 MMcf/d, all within the Delaware Basin in West Texas and Southeastern New Mexico. One additional plant, the 250 MMcf/d Peregrine Plant, is currently being constructed and expected to be completed in the second quarter of 2020.

The Permian Midland and Permian Delaware systems are interconnected and volumes may flow from one system to the other providing increased operational flexibility and redundancy.

SouthTX

The South Texas system contains approximately 900 miles of high-pressure and low-pressure gathering and transmission pipelines and three natural gas processing plants in the Eagle Ford Shale. The South Texas system processes natural gas through the Silver Oak I, Silver Oak II and Raptor gas processing plants. The Silver Oak I and II Plants (the "Silver Oak Plants") are each 200 MMcf/d cryogenic plants. The Raptor Plant is a 260 MMcf/d cryogenic plant.

We participate in two joint ventures in South Texas with a subsidiary of Southcross Energy Partners LLC, which consist of our 75% share in T2 LaSalle Gathering Company LLC ("T2 LaSalle") and our 50% share in T2 Eagle Ford Gathering Company LLC ("T2 Eagle Ford"). T2 LaSalle owns approximately 60 miles of high-pressure gathering pipeline and T2 Eagle Ford owns approximately 120 miles of high-pressure gathering pipelines. Together, these two pipelines gather and transport gas to the Silver Oak Plants. T2 Eagle Ford also owns the residue gas delivery pipelines downstream of the Silver Oak Plants. On April 1, 2019, we assumed the operatorship of T2 LaSalle and T2 Eagle Ford.

We also participate in a third joint venture in South Texas, which is with Sanchez Midstream. We own a 50% interest in the Carnero Joint Venture ("Carnero") and Sanchez Midstream owns the remaining 50% interest. Carnero owns and Targa operates the Silver Oak II Plant, the Raptor Plant and approximately 45 miles of high-pressure gathering pipeline located in La Salle, Dimmitt and Webb Counties, Texas which connects Sanchez Energy's Catarina Ranch gathering system and Comanche Ranch acreage to the Raptor Plant.

North Texas

North Texas includes two interconnected gathering systems in the Fort Worth Basin, Chico and Shackelford, and includes gas from the Barnett Shale and Marble Falls plays. The systems consist of approximately 4,700 miles of pipelines gathering wellhead natural gas.

The Chico gathering system gathers natural gas for the Chico and Longhorn plants. The Chico Plant has an aggregate processing capacity of 265 MMcf/d and an integrated fractionation capacity of 15 MBbl/d. The Longhorn Plant has processing capacity of 200 MMcf/d. The Shackelford gathering system gathers wellhead natural gas largely for the Shackelford Plant, which has processing capacity of 13 MMcf/d. Natural gas gathered from the northern and eastern portions of the Shackelford gathering system is typically transported to the Chico Plant for processing.

SouthOK

The SouthOK gathering system is located in the Ardmore and Anadarko Basins and includes the Golden Trend, SCOOP, and Woodford Shale areas of southern Oklahoma. The gathering system has approximately 2,300 miles of pipelines.

The SouthOK system includes six separate operational processing plants with a total nameplate capacity of 710 MMcf/d, including: the Coalgate, Stonewall, Hickory Hills and Tupelo facilities, which are owned by our Centrahoma Joint Venture, and our wholly-owned Velma and Velma V-60 plants. We have a 60% ownership interest in Centrahoma. The remaining 40% ownership interest in Centrahoma is held by MPLX LP ("MPLX").

WestOK

The WestOK gathering system is located in north central Oklahoma and southern Kansas' Anadarko Basin and includes the Woodford shale and the STACK. The gathering system expands into 13 counties with approximately 6,600 miles of natural gas gathering pipelines.

The WestOK system has a total nameplate capacity of 458 MMcf/d with three separate cryogenic natural gas processing plants located at the Waynoka I and II and Chester facilities, and one refrigeration plant at the Chaney Dell facility.

Coastal

Our Coastal assets, located in and offshore South Louisiana, gather and process natural gas produced from shallow-water central and western Gulf of Mexico natural gas wells and from deep shelf and deep-water Gulf of Mexico production via connections to third-party pipelines or through pipelines owned by us. Coastal consists of approximately 3,295 MMcf/d of natural gas processing capacity, 11 MBbl/d of integrated fractionation capacity, 980 miles of onshore gathering system pipelines, and 170 miles of offshore gathering system pipelines. The processing plants are comprised of five wholly-owned and operated plants, one partially owned and operated plant, and two partially owned plants which are non-operated. Toca, a partially owned, non-operated plant, was shut down in January 2019 and has been excluded from the preceding statistics. Our Coastal plants have access to markets across the U.S. through the interstate natural gas pipelines to which they are interconnected. The industry continues to rationalize gas processing capacity along the western Louisiana Gulf Coast with most of the producer volumes going to more efficient plants, such as our Barracuda, Lowry and Gillis plants.

Badlands

The Badlands operations are located in the Bakken and Three Forks Shale plays of the Williston Basin in North Dakota and include approximately 510 miles of crude oil gathering pipelines, 120 MBbl of operational crude oil storage capacity at the Johnsons Corner Terminal, 30 MBbl of operational crude oil storage capacity at the Alexander Terminal, 30 MBbl of operational crude oil storage at New Town and 25 MBbl of operational crude oil storage at Stanley. The Badlands assets also include approximately 280 miles of natural gas gathering pipelines and the Little Missouri I-III natural gas processing plants, which have a gross processing capacity of approximately 90 MMcf/d. Additionally, Targa operates the 200 MMcf/d Little Missouri 4 plant ("LM4 Plant"), in which Targa Badlands and Hess Midstream Partners LP each own a 50% interest, which was completed in the third quarter of 2019.

In April 2019, we closed on the sale of a 45% interest in Targa Badlands to Blackstone. Targa continues to be the operator of Badlands and holds majority governance rights.

The following table lists the Gathering and Processing segment's processing plants and related volumes for the year ended December 31, 2019:

Facility	Process Type (1)	Operated /Non-Operated	% Owned	Location	Gross Processing Capacity (MMcf/d) (2)	Gross Plant Natural Gas Inlet Throughput Volume (MMcf/d) (3) (4) (5)	Gross NGL Production (MBbl/d) (3) (4) (5)
Permian Midland							
Consolidator (6)	Cryo	Operated	72.8	Reagan County, TX	150.0		
Midkiff (6)	Cryo	Operated	72.8	Reagan County, TX	80.0		
Driver (6)	Cryo	Operated	72.8	Midland County, TX	200.0		
Benedum (6)	Cryo	Operated	72.8	Upton County, TX	45.0		
Edward (6)	Cryo	Operated	72.8	Upton County, TX	200.0		
Buffalo (6)	Cryo	Operated	72.8	Martin County, TX	200.0		
Joyce (6)	Cryo	Operated	72.8	Upton County, TX	200.0		
Johnson (6)	Cryo	Operated	72.8	Midland County, TX	200.0		
Hopson (6)	Cryo	Operated	72.8	Midland County, TX	250.0		
Pembrook (6)	Cryo	Operated	72.8	Upton County, TX	250.0		
Mertzon	Cryo	Operated	100.0	Irion County, TX	52.0		
Sterling	Cryo	Operated	100.0	Sterling County, TX	92.0		
Tarzan	Cryo	Operated	100.0	Martin County, TX	10.0		
High Plains	Cryo	Operated	100.0	Midland County, TX	200.0		
				Area Total	2,129.0	1,489.1	209.1
Permian Delaware							
Sand Hills	Cryo	Operated	100.0	Crane County, TX	165.0		
Loving	Cryo	Operated	100.0	Loving County, TX	70.0		
Oahu	Cryo	Operated	100.0	Pecos County, TX	60.0		
Wildcat	Cryo	Operated	100.0	Winkler County, TX	250.0		
Falcon	Cryo	Operated	100.0	Culberson County, TX	250.0		
Saunders (7)	Cryo	Operated	100.0	Lea County, NM	60.0		
Eunice (7)	Cryo	Operated	100.0	Lea County, NM	110.0		
Monument (7) (16)	Cryo	Operated	100.0	Lea County, NM	85.0		
				Area Total	1,050.0	599.7	78.6
SouthTX							
Silver Oak I	Cryo	Operated	100.0	Bee County, TX	200.0		
Silver Oak II	Cryo	Operated	50.0	Bee County, TX	200.0		
Raptor	Cryo	Operated	50.0	La Salle County, TX	260.0		
				Area Total	660.0	321.2	41.6
North Texas							
Chico (8)	Cryo	Operated	100.0	Wise County, TX	265.0		
Shackelford	Cryo	Operated	100.0	Shackelford County, TX	13.0		
Longhorn	Cryo	Operated	100.0	Wise County, TX	200.0		
				Area Total	478.0	226.9	26.8
SouthOK (9)							
Coalgate	Cryo	Operated	60.0	Coal County, OK	80.0		
Stonewall	Cryo	Operated	60.0	Coal County, OK	200.0		
Tupelo	Cryo	Operated	60.0	Coal County, OK	120.0		
Hickory Hills	Cryo	Operated	60.0	Hughes County, OK	150.0		
Velma	Cryo	Operated	100.0	Stephens County, OK	100.0		
Velma V-60	Cryo	Operated	100.0	Stephens County, OK	60.0		
				Area Total	710.0	606.1	67.1
WestOK (9)							
Waynoka I	Cryo	Operated	100.0	Woods County, OK	200.0		
Waynoka II	Cryo	Operated	100.0	Woods County, OK	200.0		
Chaney Dell (10)	RA	Operated	100.0	Major County, OK	30.0		
Chester (10)	Cryo	Operated	100.0	Woodward County, OK	28.0		
				Area Total	458.0	330.2	21.6
Coastal (11)							
Gillis (12)	Cryo	Operated	100.0	Calcasieu Parish, LA	180.0		
Acadia (10)	Cryo	Operated	100.0	Acadia Parish, LA	80.0		
Big Lake (13)	Cryo	Operated	100.0	Calcasieu Parish, LA	180.0		
VESCO	Cryo	Operated	76.8	Plaquemines Parish, LA	750.0		
Barracuda	Cryo	Operated	100.0	Cameron Parish, LA	190.0		
Lowry (14)	Cryo	Operated	100.0	Cameron Parish, LA	265.0		
Terrebone (15)	RA	Non-operated	8.4	Terrebonne Parish, LA	950.0		
Toca (17)	Cryo/RA	Non-operated	12.6	St. Bernard Parish, LA	1,150.0		
Sea Robin	Cryo	Non-operated	0.9	Vermillion Parish, LA	700.0		
				Area Total	4,445.0	748.3	46.8
Badlands							
Little Missouri I-III (18)	Cryo/RA	Operated	55.0	McKenzie County, ND	90.0		
Little Missouri IV	RA	Operated	27.5	McKenzie County, ND	200.0		
				Area Total	290.0	116.7	13.8
				Segment System Total	10,220.0	4,438.2	505.4

(1) Cryo – Cryogenic Processing; RA – Refrigerated Absorption Processing.
(2) Gross processing capacity represents 100% of ownership interests and may differ from nameplate processing capacity due to multiple factors including items such as compression limitations, and quality and composition of the gas being processed.
(3) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of the natural gas processing plant, except for Badlands which represents the total wellhead gathered volume.
(4) Plant natural gas inlet and NGL production volumes represent 100% of ownership interests for our consolidated VESCO joint venture, Silver Oak II, Raptor, Coalgate, Stonewall, Tupelo, and Hickory Hills plants and our ownership share of volumes for other partially owned plants that we proportionately consolidate based on our ownership interest which may be adjustable subject to an annual redetermination based on our proportionate share of plant production.
(5) Per day Gross Plant Natural Gas Inlet and NGL Production statistics for plants listed above are based on the number of calendar days during 2019.
(6) Gross plant natural gas inlet throughput volumes and gross NGL production volumes for WestTX are presented on a pro-rata net basis representing our undivided ownership interest in WestTX, which we proportionately consolidate in our financial statements.
(7) Includes throughput other than plant inlet, primarily from compressor stations.
(8) The Chico plant has fractionation capacity of approximately 15 MBbl/d.
(9) Certain processing facilities in these business units are capable of processing more than their nameplate capacity and when capacity is exceeded the facilities will off-load volumes to other processors, as needed. The gross plant natural gas inlet throughput volume includes these off-loaded volumes.
(10) Plant is idle.
(11) Coastal also includes two offshore gathering systems which have a combined length of approximately 200 miles.
(12) The Gillis plant has fractionation capacity of approximately 11 MBbl/d.
(13) Plant is available and operates subject to market conditions.
(14) Plant restarted operation in March 2019.
(15) Plant is anticipated to shutdown on March 31, 2020.
(16) The Monument plant has fractionation capacity of approximately 1.8 MBbl/d.
(17) The Toca plant was shut down in January 2019, but has been retained in this table to include its volumes for 2019.
(18) Little Missouri Trains I and II are refrigeration plants and Little Missouri Train III is a Cryo plant.

Logistics and Transportation Segment

Our Logistics and Transportation segment is also referred to as our Downstream Business. Our Downstream Business includes the activities and assets necessary to transport and convert mixed NGLs into NGL products and also includes other assets and value-added services described below. The Logistics and Transportation segment includes Grand Prix, as well as our equity interest in GCX. The associated assets, including these pipelines, are generally connected to and supplied in part by our Gathering and Processing segment and, except for the pipelines and smaller terminals, are located predominantly in Mont Belvieu and Galena Park, Texas, and in Lake Charles, Louisiana. Our fractionation, pipeline transportation, storage and terminaling businesses include approximately 2,000 miles of company-owned pipelines to transport mixed NGLs and specification products.

The Logistics and Transportation segment also transports, distributes and markets NGLs via terminals and transportation assets across the U.S. We own or commercially manage terminal facilities in a number of states, including Texas, Oklahoma, Louisiana, Arizona, California, Florida, Alabama, Mississippi, Tennessee, Kentucky and New Jersey. The geographic diversity of our assets provides direct access to many NGL customers as well as markets via trucks, barges, ships, rail cars and open-access regulated NGL pipelines owned by third parties.

Additional description of the Logistics and Transportation segment assets and business activities associated with Pipelines, Fractionation, NGL Storage and Terminaling, Petroleum Logistics, NGL Distribution and Marketing, Wholesale Domestic Marketing, Refinery Services, Commercial Transportation and Natural Gas Marketing follows below.

Pipelines

Our primary pipeline assets are Grand Prix and our equity interest in GCX.

Grand Prix connects our gathering and processing positions throughout the Permian Basin, North Texas, and Southern Oklahoma (as well as third-party positions) to our fractionation and storage complex in the NGL market hub at Mont Belvieu, Texas. Grand Prix transports NGLs from the Permian Basin on a 24-inch diameter pipeline with a capacity of 300 MMBbl/d, expandable to 550 MMBbl/d, and from North Texas and Southern Oklahoma via pipeline of varying capacity, which both connect to a 30-inch diameter segment into Mont Belvieu. The final segment has a 450 MMBbl/d capacity, which is expandable to 950 MMBbl/d. We own a 56% interest in the Permian and Mont Belvieu segments of Grand Prix through the Grand Prix Joint Venture. Volumes flowing on the pipeline from the Permian Basin to Mont Belvieu accrue to the Grand Prix Joint Venture, while the volumes flowing from North Texas and Oklahoma to Mont Belvieu accrue solely to Targa's benefit.

GCX Pipeline transports natural gas from the Waha hub in West Texas to Agua Dulce in South Texas and has a capacity of 1.98 Bcf/d. GCX DevCo JV, of which we own a 20% interest, owns a 25% interest in GCX Pipeline, which is operated by KMTP.

Additionally, through our 50% ownership interest in Cayenne Pipeline, LLC, we operate the Cayenne pipeline, which transports mixed NGLs from VESCO in Venice, Louisiana, to an interconnection with a third-party NGL pipeline in Toca, Louisiana.

Fractionation

After being extracted in the field, mixed NGLs are typically transported to a centralized facility for fractionation where the mixed NGLs are separated into discrete NGL products: ethane, ethane-propane mix, propane, normal butane, iso-butane and natural gasoline.

Contracts for our NGL fractionation services are fee-based arrangements. These fees are subject to adjustment for changes in certain fractionation expenses, including energy costs. The operating results of our NGL fractionation business are dependent upon the volume of mixed NGLs fractionated, the level of fractionation fees charged and product gains/losses from fractionation.

We believe that sufficient volumes of mixed NGLs will be available for fractionation in commercially viable quantities for the foreseeable future due to historical increases in NGL production from shale plays and other shale-technology-driven resource plays in areas of the U.S. that include Texas, New Mexico, Oklahoma and the Rockies and certain other basins accessed by pipelines to Mont Belvieu, as well as from conventional production of NGLs in areas such as the Permian Basin, Mid-Continent, East Texas, South Louisiana and shelf and deep-water Gulf of Mexico. Hydrocarbon dew point specifications implemented by individual natural gas pipelines and the Policy Statement on *Provisions Governing Natural Gas Quality and Interchangeability in Interstate Natural Gas Pipeline Company Tariffs* enacted in 2006 by the Federal Energy Regulatory Commission ("FERC") should result in volumes of mixed NGLs being available for fractionation because natural gas requires processing or conditioning to meet pipeline quality specifications. These requirements establish a base volume of mixed NGLs during periods when it might be otherwise uneconomical to process certain sources of natural gas. Furthermore, significant volumes of mixed NGLs are contractually committed to our NGL fractionation facilities.

Although competition for NGL fractionation services is primarily based on the fractionation fee, the ability of an NGL fractionator to obtain mixed NGLs and distribute NGL products is also an important competitive factor. This ability is a function of the existence of storage infrastructure and supply and market connectivity necessary to conduct such operations. We believe that the location, scope and capability of our logistics assets, including our transportation and distribution systems, give us access to both substantial sources of mixed NGLs and a large number of end-use markets.

Our fractionation assets include ownership interests in three stand-alone fractionation facilities that are located on the Gulf Coast, two of which we operate at Mont Belvieu, Texas and at Lake Charles, Louisiana. We have an equity investment in the third fractionation facility, Gulf Coast Fractionators LP ("GCF"), also located at Mont Belvieu. In addition to the three stand-alone facilities included in the Logistics and Transportation segment, we also own fractionation assets at Chico, Monument and Gillis included in our Gathering and Processing segment.

Five of the six existing fractionation trains at the Mont Belvieu facility representing a gross capacity of 493.0 MBbl/d are part of our 88%-owned Cedar Bayou Fractionators. A 100 MBbl/d fractionation train, Train 6, began operations in the second quarter of 2019. Train 6 JV, a joint venture between Targa and Stonepeak, owns 100% interest in the fractionation train. Certain fractionation-related infrastructure for Train 6, such as storage caverns and brine handling, were funded and are owned 100% by Targa.

Two additional fractionation trains, which are currently under construction at the Mont Belvieu facility, are not part of CBF or the Train 6 JV. The additional fractionation trains are being fully integrated with our existing Gulf Coast NGL storage, terminaling and delivery infrastructure, which includes an extensive network of connections to key petrochemical and industrial customers as well as our LPG export terminal at Galena Park on the Houston Ship Channel. The additional fractionation trains are: (1) the 110 MBbl/d Train 7, a joint venture with Williams, which is expected to begin operations by the end of the first quarter 2020 and (2) the 110 MBbl/d Train 8, which is expected to begin operations by the end of the third quarter 2020.

We also have a natural gasoline hydrotreater at Mont Belvieu, Texas that removes sulfur from natural gasoline, allowing customers to meet stringent fuel content standards. The facility has a capacity of 35 MBbl/d and is supported by long-term fee-based contracts that have certain guaranteed volume commitments and/or provisions for deficiency payments.

The following table details the Logistics and Transportation segment's fractionation and treating facilities:

Facility	% Owned	Gross Capacity (MBbl/d) (1)	Gross Throughput 2019 (MBbl/d)
Operated Facilities:			
Lake Charles Fractionator (Lake Charles, LA) (2)	100.0	55.0	4.6
Train 6 Fractionator (Mont Belvieu, TX) (3)	20.0	100.0	73.5
Cedar Bayou Fractionators (Mont Belvieu, TX) (4)	88.0	493.0	430.8
Targa LSNG Hydrotreater (Mont Belvieu, TX)	100.0	35.0	35.8
Non-operated Facilities:			
Gulf Coast Fractionator (Mont Belvieu, TX)	38.8	125.0	125.4

(1) Actual fractionation capacities may vary due to the Y-grade composition of the gas being processed and does not contemplate ethane rejection.
(2) Lake Charles Fractionator runs in a mode of ethane/propane splitting for a local petrochemical customer and is configured to handle raw product.
(3) Train 6 began operations in the second quarter of 2019.
(4) Gross capacity represents 100% of the volume. Capacity includes 40 MBbl/d of additional back-end butane/gasoline fractionation capacity.

NGL Storage and Terminaling

In general, our NGL storage assets provide warehousing of mixed NGLs, NGL products and petrochemical products in underground wells, which allows for the injection and withdrawal of such products at various times in order to meet supply and demand cycles. Similarly, our terminaling operations provide the inbound/outbound logistics and warehousing of mixed NGLs, NGL products and petrochemical products in above-ground storage tanks. Our NGL underground storage and terminaling facilities serve single markets, such as propane, as well as multiple products and markets. For example, the Mont Belvieu and Galena Park facilities have extensive pipeline connections for mixed NGL supply and delivery of component NGLs, including Grand Prix. In addition, some of our facilities are connected to marine, rail and truck loading and unloading facilities that provide services and products to our customers. We provide long and short-term storage and terminaling services and throughput capability to third-party customers for a fee.

Across the Logistics and Transportation segment, we own 34 storage wells at our facilities with a gross NGL storage capacity of approximately 72 MMBbl, and operate 6 non-owned wells, the usage of which may be limited by brine handling capacity, which is utilized to displace NGLs from storage.
We operate our storage and terminaling facilities to support our key fractionation facilities at Mont Belvieu and Lake Charles for receipt of mixed NGLs and storage of fractionated NGLs to service the petrochemical, refinery, export and heating customers/markets as well as our wholesale domestic terminals that focus on logistics to service the heating market customer base. Our international export assets include our facilities at both Mont Belvieu and the Galena Park Marine Terminal near Houston, Texas, which have the capability to load propane, butane and international grade low ethane propane. The facilities currently have the capacity to export approximately 10 MMBbl per month of propane and/or butane. We have the capability to load VLGC vessels, alongside small and medium sized export vessels. We continue to experience demand growth for U.S.-based NGLs (both propane and butane) for export into international markets and are in the process of enhancing our loading capabilities.

The following table details the Logistics and Transportation segment's NGL storage and terminaling facilities:

Facility	% Owned	Location	Description	Throughput for 2019 (MMgal)	Number of Operational Wells	Gross Storage Capacity (MMBbl)
Galena Park Marine Terminal (1)	100	Harris County, TX	NGL import/export terminal	5,162.8	N/A	0.8
Mont Belvieu Terminal & Storage	100	Chambers County, TX	Transport and storage terminal	21,860.0	22 (2)	50.8
Hackberry Terminal & Storage	100	Cameron Parish, LA	Storage terminal	1,623.0	12 (3)	20.9
Patriot	100	Harris County, TX	Dock and land for expansion (Not in service)	N/A	N/A	N/A

(1) Volumes reflect total import and export across the dock/terminal and may include volumes that have also been handled at the Mont Belvieu Terminal.
(2) Excludes six non-owned wells which we operate on behalf of Chevron Phillips Chemical Company LLC and one additional non-owned well that is being prepared for operations. One additional well has been drilled and is being prepared for operations. One additional well is permitted.
(3) Five of 12 owned wells leased to Citgo Petroleum Corporation under long-term leases.

Petroleum Logistics

Our Petroleum Logistics business owns and operates a storage and terminaling facility in Channelview, Texas, including a 35,000 Bbl/d nameplate capacity crude oil and condensate splitter (the "Channelview Splitter"). This facility serves the refined petroleum products, crude oil, LPG, and petrochemicals markets. The Channelview storage and terminaling facility's throughput for the year ended December 31, 2019, was 219.7 MMgal and the gross storage capacity was 0.6 MMBbl. The Channelview Splitter splits crude oil and condensate into its various components, including naphtha, distillate, gas oil, kerosene/jet fuel and liquefied petroleum gas and has segregated storage for the crude and condensate and each of the components.

NGL Distribution and Marketing

We market our own NGL production and also purchase component NGL products from other NGL producers and marketers for resale. Additionally, we also purchase product for resale in our Logistics and Transportation segment, including exports. During the year ended December 31, 2019, our distribution and marketing services business sold an average of 651.0 MBbl/d of NGLs.

We generally purchase mixed NGLs at a monthly pricing index less applicable fractionation, transportation and marketing fees and resell these component products to petrochemical manufacturers, refineries and other marketing and retail companies. This is primarily a physical settlement business in which we earn margins from purchasing and selling NGL products from customers under contract. We also earn margins by purchasing and reselling NGL products in the spot and forward physical markets. To effectively serve our distribution and marketing customers, we contract for and use many of the assets included in our Logistics and Transportation segment.

Wholesale Domestic Marketing

Our wholesale domestic propane marketing operations primarily sell propane and related logistics services to major multi-state retailers, independent retailers and other end-users. Our propane supply primarily originates from both our refinery/gas supply contracts and our other owned or managed logistics and transportation assets. We sell propane at a fixed posted price or at a market index basis at the time of delivery and in some circumstances, we earn margin on a netback basis.

The wholesale domestic propane marketing business is significantly impacted by seasonal and weather-driven demand, particularly in the winter, which can impact the price and volume of propane sold in the markets we serve.

Refinery Services

In our refinery services business, we typically provide NGL balancing services through contractual arrangements with refiners to purchase and/or market propane and to supply butanes. We use our commercial transportation assets (discussed below) and contract for and use the storage, transportation and distribution assets included in our Logistics and Transportation segment to assist refinery customers in managing their NGL product demand and production schedules. This includes both feedstocks consumed in refinery processes and the excess NGLs produced by other refining processes. Under typical netback purchase contracts, we generally retain a portion of the resale price of NGL sales or receive a fixed minimum fee per gallon on products sold. Under netback sales contracts, fees are earned for locating and supplying NGL feedstocks to the refineries based on a percentage of the cost to obtain such supply or a minimum fee per gallon.

Key factors impacting the results of our refinery services business include production volumes, prices of propane and butanes, as well as our ability to perform receipt, delivery and transportation services in order to meet refinery demand.

Commercial Transportation

Our NGL transportation and distribution infrastructure includes a wide range of assets supporting both third-party customers and the delivery requirements of our marketing and asset management business. We provide fee-based transportation services to refineries and petrochemical companies throughout the Gulf Coast area. Our assets are also deployed to serve our wholesale domestic distribution terminals, fractionation facilities, underground storage facilities and pipeline injection terminals. These distribution assets provide a variety of ways to transport products to and from our customers.

Our transportation assets, as of December 31, 2019, include approximately 698 railcars that we lease and manage, approximately 138 leased and managed transport tractors and 2 company-owned pressurized NGL barges.

The following table details the Logistics and Transportation segment's raw NGL, propane and butane terminaling facilities:

Facility	% Owned	Location	Description	Throughput for 2019 (MMgal) (1)	Usable Storage Capacity (MMgal)
Calvert City Terminal	100	Marshall County, KY	Propane terminal	11.3	0.1
Greenville Terminal	100	Washington County, MS	Marine propane terminal	23.7	1.5
Port Everglades Terminal	100	Broward County, FL	Marine propane terminal	17.3	1.6
Tyler Terminal	100	Smith County, TX	Propane terminal	14.5	0.2
Abilene Transport (2)	100	Taylor County, TX	Raw NGL transport terminal	15.7	0.1
Bridgeport Transport (2)	100	Jack County, TX	Raw NGL transport terminal	116.0	0.1
Gladewater Transport (2)	100	Gregg County, TX	Raw NGL transport terminal	3.6	0.3
Chattanooga Terminal	100	Hamilton County, TN	Propane terminal	16.8	0.9
Sparta Terminal	100	Sparta County, NJ	Propane terminal	13.5	0.2
Hattiesburg Terminal (3)	50	Forrest County, MS	Propane terminal	352.8	179.8
Winona Terminal	100	Flagstaff County, AZ	Propane terminal	12.2	0.3
Jacksonville Transload (4)	100	Duval County, FL	Butane transload	1.6	—
Fort Lauderdale Transload (4)	100	Broward County, FL	Butane transload	1.8	—
Eagle Lake Transload (4)	100	Polk County, FL	Butane/propane transload	4.6	—

(1) Throughputs include volumes related to exchange agreements and third-party storage agreements.
(2) Volumes reflect total transport and injection volumes.
(3) Throughput volume reflects 100% of the facility capacity.
(4) Rail-to-truck transload equipment.

Natural Gas Marketing

We also market natural gas available to us from the Gathering and Processing segment, purchase and resell natural gas in selected U.S. markets and manage the scheduling and logistics for these activities.

Seasonality

Overall, parts of our business are impacted by seasonality. Our downstream marketing business can be significantly impacted by seasonal and weather-driven demand, which can impact the price and volume of product sold in the markets we serve, as well as the level of inventory we hold in order to meet anticipated demand. See further discussion of the extent to which our business is affected by seasonality in "Item 1A. Risk Factors."

Operational Risks and Insurance

We are subject to all risks inherent in the midstream natural gas, NGLs and crude oil businesses. These risks include, but are not limited to, explosions, fires, mechanical failure, terrorist attacks, product spillage, weather, nature and inadequate maintenance of rights of way. These risks could result in damage to or destruction of operating assets and other property, or could result in personal injury, loss of life or environmental pollution, as well as curtailment or suspension of operations at the affected facility. Targa maintains, on behalf of us and our subsidiaries, general public liability, property, boiler and machinery and business interruption insurance in amounts that we consider to be appropriate for such risks. Such insurance is subject to deductibles that we consider reasonable and not excessive given the current insurance market environment.

The occurrence of a significant loss that is not insured, fully insured or indemnified against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our operations and financial condition. While we currently maintain levels and types of insurance that we believe to be prudent under current insurance industry market conditions, our inability to secure these levels and types of insurance in the future could negatively impact our business operations and financial stability, particularly if an uninsured loss were to occur. No assurance can be given that we will be able to maintain these levels of insurance in the future at rates considered commercially reasonable, particularly named windstorm coverage and contingent business interruption coverage for our onshore operations.

Competition

We face strong competition in acquiring new natural gas or crude oil supplies. Competition for natural gas and crude oil supplies is primarily based on the location of gathering and processing facilities, pricing arrangements, reputation, efficiency, flexibility, treating capabilities (as applicable), reliability and access to end-use markets or liquid marketing hubs. Competitors to our gathering and processing operations include other natural gas gatherers and processors, such as major interstate and intrastate pipeline companies, master limited partnerships and oil and gas producers. Our major competitors for natural gas supplies in our current operating regions include DCP, Enable Midstream Partners, L.P., Energy Transfer Equity, L.P. ("Energy Transfer"), Enlink Midstream Partners LP, Enterprise Products Partners L.P. ("Enterprise"), Kinder Morgan, Inc. ("Kinder Morgan"), MPLX, ONEOK, Inc. ("ONEOK"), WTG Gas Processing, L.P. and several other pipeline companies. Our competitors for crude oil gathering services in North Dakota include Crestwood Equity Partners LP, Kinder Morgan, MPLX and Summit Midstream Partners, LLC. Our competitors may have greater financial resources than we possess.

We also compete for NGL supplies for Grand Prix. Competition for NGL supplies is primarily based on the location of gathering and processing facilities and their connectivity to NGL pipeline takeaway options, access to end-use markets or liquid marketing hubs, pricing and contractual arrangements, reputation, efficiency, flexibility, and reliability. Competitors to our NGL pipeline include other midstream providers with NGL transportation capabilities, such as major interstate and intrastate pipeline companies, master limited partnerships and midstream natural gas and NGL companies. Our major competitors for NGL supplies in our current operating regions include DCP, Energy Transfer, Enterprise and ONEOK.

Additionally, we face competition for mixed NGLs supplies at our fractionation facilities. Our competitors include large oil, natural gas and petrochemical companies. The fractionators in which we own an interest in the Mont Belvieu region compete for volumes of mixed NGLs with other fractionators also located at Mont Belvieu, Texas. Among the primary competitors are Enterprise, LoneStar NGL LLC ("LoneStar") and ONEOK. In addition, certain producers fractionate mixed NGLs for their own account in captive facilities. The Mont Belvieu fractionators also compete on a more limited basis with fractionators in Conway, Kansas and a number of decentralized, smaller fractionation facilities in Texas, Louisiana and New Mexico. Our other fractionation facilities compete for mixed NGLs with the fractionators at Mont Belvieu as well as other fractionation facilities located in Louisiana. Our customers who are significant producers of mixed NGLs and NGL products or consumers of NGL products may develop their own fractionation facilities in lieu of using our services. Our primary competitors in providing export services to our customers are Enterprise, LoneStar and Phillips 66.

We also compete for NGL products to market through our Logistics and Transportation segment. Our competitors include major oil and gas producers who market NGL products for their own account and for others. Additionally, we compete with several other NGL marketing companies, including BP p.l.c., DCP, Energy Transfer, Enterprise and ONEOK.

Regulation of Operations

Regulation of pipeline gathering and transportation services, natural gas, NGL and crude oil sales, and transportation of natural gas, NGLs and crude oil may affect certain aspects of our business and the market for our products and services.

Gathering Pipeline Regulation

Our natural gas gathering operations are typically subject to ratable take and common purchaser statutes in the states in which we operate. The common purchaser statutes generally require gathering pipelines to purchase or take without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another or one source of supply over another. The regulations under these statutes can have the effect of imposing some restrictions on our ability as an owner of gathering facilities to decide with whom we contract to gather natural gas. The states in which we operate have adopted complaint-based regulation of natural gas gathering activities, which allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to gathering access and rate discrimination. The rates we charge for gathering are deemed just and reasonable unless challenged in a complaint. We cannot predict whether such a complaint will be filed against us in the future. Failure to comply with state regulations can result in the imposition of administrative, civil and criminal penalties.

Section 1(b) of the Natural Gas Act of 1938 ("NGA") exempts natural gas gathering facilities from regulation as a natural gas company by FERC under the NGA. We believe that the natural gas pipelines in our gathering systems, including the gas gathering systems that are part of the Badlands and of the Pelican and Seahawk gathering systems, meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company. However, to the extent our gathering systems buy and sell natural gas, such gatherers, in their capacity as buyers and sellers of natural gas, are now subject to Order No. 704. See "—Regulation of Operations—FERC Market Transparency Rules."

Natural Gas Processing

Our natural gas gathering and processing operations are not presently subject to FERC regulation. However, since May 2009, we have been required to report to FERC information regarding natural gas sale and purchase transactions for some of our operations depending on the volume of natural gas transacted during the prior calendar year. See "—Regulation of Operations—FERC Market Transparency Rules." There can be no assurance that our processing operations will continue to be exempt from other FERC regulation in the future.

Sales of Natural Gas, NGLs and Crude Oil

The price at which we buy and sell natural gas, NGLs and crude oil is currently not subject to federal rate regulation and, for the most part, is not subject to state rate regulation. However, with regard to our physical purchases and sales of these energy commodities and any related hedging activities that we undertake, we are required to observe anti-market manipulation laws and related regulations enforced by FERC and/or the Commodities Futures Trading Commission ("CFTC"). See "—Regulation of Operations—EP Act of 2005." Since May 2009, we have been required to report to FERC information regarding natural gas sale and purchase transactions for some of our operations depending on the volume of natural gas transacted during the prior calendar year. See "—Regulation of Operations—FERC Market Transparency Rules." Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third-party damage claims by, among others, market participants, sellers, royalty owners and taxing authorities.

Interstate Natural Gas

We own (in conjunction with Pioneer) and operate the Driver Residue Pipeline, a gas transmission pipeline extending from our Driver processing plant in West Texas just over ten miles to points of interconnection with intrastate and interstate natural gas transmission pipelines. We have obtained a waiver from FERC of the requirements pertaining to the filing of an initial rate for service, the filing of a tariff and compliance with specified accounting and reporting requirements for the Driver Residue Pipeline. As such, the Driver Residue Pipeline is not currently subject to conventional rate regulation; to requirements FERC imposes on "open access" interstate natural gas pipelines; to the obligation to file and maintain a tariff; or to the obligation to conform to certain business practices and to file certain reports. If, however, we receive a *bona fide* request for firm service on the Driver Residue Pipeline from a third party, FERC would reexamine the waivers it has granted us and would require us to file for authorization to offer "open access" transportation under its regulations, which would impose additional costs upon us.

Interstate Liquids

Targa NGL Pipeline Company LLC ("Targa NGL") has interstate NGL pipelines that are considered common carrier pipelines subject to regulation by FERC under the Interstate Commerce Act (the "ICA"). More specifically, Targa NGL owns an eight-inch diameter pipeline, a 20-inch diameter pipeline, and a 12-inch diameter pipeline that run between Mont Belvieu, Texas, and Galena Park, Texas. Each of these pipelines is regulated under the ICA and is part of an extensive mixed NGL and purity NGL pipeline receipt and delivery system that provides services to domestic and foreign import and export customers.

Additionally, in 2019, Targa NGL began operating portions of Grand Prix that transports NGLs from Oklahoma to Mont Belvieu, Texas. On July 27, 2018, Targa NGL submitted a petition for declaratory order to FERC on a proposed rate structure and terms of service for such portions of Grand Prix. The Commission granted Targa NGL's petition for declaratory order subject to certain conditions on March 11, 2019. Targa NGL requested rehearing on April 10, 2019, which is pending at FERC.

Additionally, Grand Prix entered full service during the third quarter of 2019, providing transportation for mixed NGLs from the Permian Basin, including points in New Mexico, to Mont Belvieu, Texas.

The ICA requires that we maintain tariffs on file with FERC for each of these pipelines described above. Those tariffs set forth the rates we charge for providing transportation services as well as the rules and regulations governing these services. The ICA requires, among other things, that rates on interstate common carrier pipelines be "just and reasonable" and non-discriminatory.

Targa NGL also owns a twenty-inch diameter pipeline that runs between Mont Belvieu, Texas, and Galena Park, Texas and a twelve-inch diameter pipeline that runs between Mont Belvieu, Texas and Lake Charles, Louisiana, each of which transport NGLs and that have qualified for a waiver of applicable FERC regulatory requirements under the ICA based on current circumstances. Additionally, the crude oil pipeline system that is part of the Badlands assets also qualifies for such a waiver.

All such waivers are subject to revocation, however, should a particular pipeline's circumstances change. FERC could, either at the request of other entities or on its own initiative, assert that some or all of these pipelines no longer qualify for a waiver. In the event that FERC were to determine that one more of these pipelines no longer qualified for waiver, we would likely be required to file a tariff with FERC for the applicable pipeline(s) and delivery point(s), provide a cost justification for the transportation charge, and provide service to all potential shippers without undue discrimination.

Many existing pipelines, including Grand Prix and some of Targa NGL's pipelines, may utilize the FERC oil pipeline indexing rate methodology which, as currently in effect, allows common carriers to change their rates within prescribed ceiling levels that are tied to changes in the Producer Price Index. FERC's indexing methodology is subject to review every five years. On March 15, 2018, FERC issued a Revised Policy Statement on Treatment of Income Taxes ("Revised Policy Statement") stating, among other things, that with respect to oil and refined products pipelines subject to FERC jurisdiction, the impacts of the Revised Policy Statement and the Tax Cuts and Jobs Act of 2017 on the costs of FERC-regulated oil and NGL pipelines will be reflected in FERC's next five-year review of the oil pipeline index, which will generate the index level to be effective July 1, 2021. FERC's establishment of a just and reasonable rate, including the determination of the appropriate oil pipeline index, is based on many components, and tax-related changes will affect two such components, the allowance for income taxes and the amount for accumulated deferred income taxes, while other pipeline costs also will continue to affect FERC's determination of the appropriate pipeline index. Accordingly, depending on FERC's application of its indexing rate methodology for the next five-year term of index rates, the Revised Policy Statement and tax effects related to the Tax Cuts and Jobs Act of 2017 may impact our revenues associated with any transportation services we may provide pursuant to cost-of-service based rates in the future, including indexed rates.

Tribal Lands

Our intrastate natural gas pipelines in North Dakota are subject to the various regulations of the State of North Dakota. In addition, various federal agencies within the U.S. Department of the Interior, particularly the federal Bureau of Land Management ("BLM"), Office of Natural Resources Revenue (formerly the Minerals Management Service) and the Bureau of Indian Affairs, as well as the Three Affiliated Tribes, promulgate and enforce regulations pertaining to operations on the Fort Berthold Indian Reservation. Please see "Other State and Local Regulation of Operations" below.

Intrastate Natural Gas

Though our natural gas intrastate pipelines are not subject to regulation by FERC as natural gas companies under the NGA, our intrastate pipelines may be subject to certain FERC-imposed reporting requirements depending on the volume of natural gas purchased or sold in a given year. See "—Regulation of Operations—FERC Market Transparency Rules."

Our intrastate pipelines located in Texas are regulated by the Railroad Commission of Texas (the "RRC"). Our Texas intrastate pipeline, Targa Intrastate Pipeline LLC ("Targa Intrastate"), owns the intrastate pipeline that transports natural gas from our Shackelford processing plant to an interconnect with Atmos Pipeline-Texas that in turn delivers gas to the West Texas Utilities Company's Paint Creek Power Station. Targa Intrastate also owns a 1.65-mile, ten-inch diameter intrastate pipeline that transports natural gas from a third-party gathering system into the Chico system in Denton County, Texas. Targa Intrastate is a gas utility subject to regulation by the RRC and has a tariff on file with such agency. Our other Texas intrastate pipeline, Targa Gas Pipeline LLC, owns a multi-county intrastate pipeline that transports gas in Crane, Ector, Midland, and Upton Counties, Texas, as well as some lines in North Texas. Targa Gas Pipeline LLC is a gas utility subject to regulation by the RRC and has a tariff on file with such agency.

Our Louisiana intrastate pipeline, Targa Louisiana Intrastate LLC, owns an approximately 60-mile intrastate pipeline system that receives all of the natural gas it transports within or at the boundary of the State of Louisiana. Because all such gas ultimately is consumed within Louisiana, and since the pipeline's rates and terms of service are subject to regulation by the Office of Conservation of the Louisiana Department of Natural Resources ("DNR"), the pipeline qualifies as a Hinshaw pipeline under Section 1(c) of the NGA and thus is exempt from most FERC regulation.

We have an ownership interest of 50% of the capacity in a 50-mile long intrastate natural gas transmission pipeline, which extends from the tailgate of three natural gas processing plants located near Pettus, Texas to interconnections with existing intrastate and interstate natural gas pipelines near Refugio, Texas. The capacity is held by our subsidiary, TPL SouthTex Transmission Company LP ("TPL SouthTex Transmission"), which is entitled to transport natural gas through its capacity on behalf of third parties to both intrastate and interstate markets. Because the jointly owned pipeline system was initially interconnected only with intrastate markets, each of the capacity holders qualified as an "intrastate pipeline" within the meaning of the Natural Gas Policy Act of 1978 ("NGPA") and therefore is able to provide transportation of natural gas to interstate markets under Section 311 of the NGPA. Under Sections 311 and 601 of the NGPA, an intrastate pipeline may transport natural gas in interstate commerce without becoming subject to FERC regulation as a "natural-gas company" under the NGA. Transportation of natural gas under authority of Section 311 must be filed with FERC and must be shown to be "fair and equitable." TPL SouthTex Transmission has a Statement of Operating Conditions on file with FERC. TPL SouthTex Transmission has existing rates applicable to NGPA Section 311 service. The GCX Pipeline, which went into service in late third quarter 2019, transports natural gas from the Permian and Midland Basin to markets on the Texas Gulf Coast. GCX is subject to regulation by the RRC and under Section 311 of the NGPA and, on October 25, 2019, petitioned for rate approval, requesting an effective date of September 25, 2019.

We also operate natural gas pipelines that extend from the tailgate of our processing plants to interconnections with both intrastate and interstate natural gas pipelines. Although these "plant tailgate" pipelines may operate at transmission pressure levels and may transport "pipeline quality" natural gas, we believe they are generally exempt from FERC's jurisdiction under the Natural Gas Act under FERC's "stub" line exemption. However, Targa Midland Gas Pipeline LLC ("Targa Midland") operates our Tarzan plant residue gas pipeline, which provides NGPA Section 311 service and falls outside of the "stub" line exemption. Targa Midland maintains a Statement of Operating Conditions on file with FERC.

FERC issued Order No. 849 on July 18, 2018, which became effective September 13, 2018, establishing new regulations that, among other things, require pipelines providing NGPA Section 311 service to file a new rate election for its interstate rates if the intrastate pipeline's rates on file with the state regulatory agency are reduced to reflect the reduced income tax rates adopted in the Tax Cuts and Jobs Act. If an NGPA Section 311 pipeline's interstate service rates are established pursuant to a rate filing with FERC, the pipeline is exempt from filing a new rate election if FERC has approved the interstate rates after December 22, 2017, or the pipeline has a pending rate petition at FERC on the effective date of the reduced intrastate rates. Any such petitions may reduce the rates we are permitted to charge for NGPA Section 311 service.

Texas and Louisiana have adopted complaint-based regulation of intrastate natural gas transportation activities, which allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to pipeline access and rate discrimination. The rates we charge for intrastate transportation are deemed just and reasonable unless challenged in a complaint. We cannot predict whether such a complaint will be filed against us in the future. Failure to comply with state regulations can result in the imposition of administrative, civil and criminal penalties.

Intrastate Liquids

Our intrastate NGL pipelines in Texas transport mixed and purity NGL streams between Targa's Mont Belvieu and Galena Park, Texas facilities. Grand Prix went into service during the third quarter of 2019, and provides transportation of mixed NGLs from the Permian Basin to Mont Belvieu, Texas. Further, we operate crude gathering pipelines in the Permian Basin. With respect to intrastate movements, these pipelines are not subject to FERC regulation, but are subject to rate regulation by the RRC. They are also subject to U.S. Department of Transportation ("DOT") safety regulations.

Our intrastate NGL pipelines in Louisiana gather mixed NGLs streams that we own from processing plants in Louisiana and deliver such streams to the Gillis and Lake Charles fractionators in Lake Charles, Louisiana. We deliver mixed and purity NGL streams out of our fractionator to and from Targa-owned storage, to other third-party facilities and pipelines in Louisiana. Additionally, through our 50% ownership interest in Cayenne Pipeline, LLC, we operate the Cayenne pipeline, which transports mixed NGLs from the Venice gas plant in Venice, Louisiana, to an interconnection with a third-party NGL pipeline in Toca, Louisiana. These pipelines are not subject to FERC regulation or rate regulation by the DNR, but are subject to DOT safety regulations. On May 9, 2019, the Louisiana Public Service Commission ("LPSC") approved applications to register certain pipelines of Cayenne Pipeline, LLC and Targa Downstream LLC in accordance with the LPSC 2015 General Order, Docket No. R-33390.

Other Federal Laws and Regulations Affecting Our Industry

EP Act of 2005

The EP Act of 2005 is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans, and significant changes to the statutory policy that affects all segments of the energy industry. Among other matters, the EP Act of 2005 amends the NGA to add an anti-market manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC, and furthermore provides FERC with additional civil penalty authority. The EP Act of 2005 provides FERC with the power to assess civil penalties of up to approximately $1.29 million per violation per day, adjusted annually for inflation, for violations of the NGA and approximately $1.29 million per violation per day, adjusted annually for inflation, for violations of the NGPA. The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce. In 2006, FERC issued Order No. 670 to implement the anti-market manipulation provision of the EP Act of 2005. Order No. 670 does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of gas pipelines and storage companies that provide interstate services, as well as otherwise non-jurisdictional entities to the extent the activities are conducted “in connection with” gas sales, purchases or transportation subject to FERC jurisdiction, which includes the annual reporting requirements under a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing (Order No. 704), and the quarterly reporting requirement under Order No. 735. The anti-market manipulation rule and enhanced civil penalty authority reflect an expansion of FERC’s NGA enforcement authority.

FERC Market Transparency Rules

Beginning in 2007, FERC has issued a number of rules intended to provide for greater marketing transparency in the natural gas industry, including Order Nos. 704, 720, and 735. Under Order No. 704, wholesale buyers and sellers of more than 2.2 Bcf of physical natural gas in the previous calendar year, including interstate and intrastate natural gas pipelines, natural gas gatherers, natural gas processors and natural gas marketers, are now required to report, on May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices.

Under Order No. 720, certain non-interstate pipelines delivering, on an annual basis, more than an average of 50 million MMBtu of gas over the previous three calendar years, are required to post on a daily basis certain information regarding the pipeline’s capacity and scheduled flows for each receipt and delivery point that has a design capacity equal to or greater than 15,000 MMBtu/d and interstate pipelines are required to post information regarding the provision of no-notice service. In October 2011, Order No. 720 as clarified was vacated by the Court of Appeals for the Fifth Circuit. We take the position that, at this time, all of our entities are exempt from Order No. 720 as currently effective.

Under Order No. 735, intrastate pipelines providing transportation services under Section 311 of the NGPA and Hinshaw pipelines operating under Section 1(c) of the NGA are required to report on a quarterly basis more detailed transportation and storage transaction information, including: rates charged by the pipeline under each contract; receipt and delivery points and zones or segments covered by each contract; the quantity of natural gas the shipper is entitled to transport, store, or deliver; the duration of the contract; and whether there is an affiliate relationship between the pipeline and the shipper. Order No. 735 also extends FERC’s periodic review of the rates charged by the subject pipelines from three years to five years. On rehearing, FERC reaffirmed Order No. 735 with some modifications. As currently written, this rule does not apply to our Hinshaw pipelines.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, FERC and the courts. We cannot predict the ultimate impact of these or the above regulatory changes to our natural gas operations. We do not believe that we would be affected by any such FERC action materially differently than other midstream natural gas companies with whom we compete.

Other State and Local Regulation of Operations

Our business activities are subject to various state and local laws and regulations, as well as orders of regulatory bodies pursuant thereto, governing a wide variety of matters, including operations, marketing, production, pricing, community right-to-know, protection of the environment, safety, marine traffic and other matters. In addition, the Three Affiliated Tribes promulgate and enforce regulations pertaining to operations on the Fort Berthold Indian Reservation, on which we operate a significant portion of our Badlands gathering and processing assets. The Three Affiliated Tribes is a sovereign nation having the right to enforce certain laws and regulations independent from federal, state and local statutes and regulations. For additional information regarding the potential impact of federal, state, tribal or local regulatory measures on our business, see “Risk Factors—Risks Related to Our Business.”

Environmental and Occupational Health and Safety Matters

Our business operations are subject to numerous environmental and occupational health and safety laws and regulations that may be imposed at the federal, regional, state, tribal and local levels. The activities that we conduct in connection with (i) gathering, compressing, treating, processing, transporting and selling natural gas; (ii) storing, fractionating, treating, transporting and selling NGLs and NGL products, including services to LPG exporters; (iii) gathering, storing, terminaling and selling crude oil; and (iv) storing, terminaling and selling refined petroleum products are subject to or may become subject to stringent environmental regulation. We have implemented programs and policies designed to monitor and pursue operation of our pipelines, plants and other facilities in a manner consistent with existing environmental and occupational health and safety laws and regulations, and have incurred and will continue to incur operating and capital expenditures, some of which may be material, to comply with these laws and regulations. Historically, our environmental compliance costs have not had a material adverse effect on our results of operations; however, there can be no assurance that such costs will not be material in the future or that such future compliance will not have a material adverse effect on our business and operational results.

The more significant of these existing environmental and occupational health and safety laws and regulations include the following U.S. legal standards, as amended from time to time:

- the Clean Air Act ("CAA"), which restricts the emission of air pollutants from many sources and imposes various pre-construction, operational, monitoring and reporting requirements, and that the EPA has relied upon as authority for adopting climate change regulatory initiatives relating to greenhouse gas ("GHG") emissions;
- the Federal Water Pollution Control Act, also known as the Clean Water Act, which regulates discharges of pollutants to state and federal waters and establishes the extent to which waterways are subject to federal jurisdiction and rulemaking as protected waters of the United States;
- the Comprehensive Environmental Response, Compensation and Liability Act of 1980 ("CERCLA"), which imposes liability on generators, transporters, and arrangers of hazardous substances at sites where hazardous substance releases have occurred or are threatening to occur;
- the Resource Conservation and Recovery Act ("RCRA"), which governs the generation, treatment, storage, transport, and disposal of solid wastes, including hazardous wastes;
- the Oil Pollution Act of 1990, which subjects owners and operators of onshore facilities, pipelines and other facilities, as well as lessees or permittees of areas in which offshore facilities are located, that are the site of an oil spill in waters of the United States, to liability for removal costs and damages;
- the Safe Drinking Water Act, which ensures the quality of the nation’s public drinking water through adoption of drinking water standards and controlling the injection of waste fluids into below-ground formations that may adversely affect drinking water sources;
- the Endangered Species Act, which restricts activities that may affect federally identified endangered and threatened species or their habitats through the implementation of operating restrictions or a temporary, seasonal, or permanent ban in affected areas;
- the National Environmental Policy Act (NEPA), which requires federal agencies to evaluate major agency actions having the potential to impact the environment and that may require the preparation of environmental assessments and more detailed environmental impact statements that may be made available for public review and comment; and
- the Occupational Safety and Health Act, which establishes workplace standards for the protection of the health and safety of employees, including the implementation of hazard communications programs designed to inform employees about hazardous substances in the workplace, potential harmful effects of these substances, and appropriate control measures.

These environmental and occupational health and safety laws and regulations generally restrict the level of substances generated as a result of our operations that may be emitted to ambient air, discharged to surface water, and disposed or released to surface and below-ground soils and ground water. Additionally, there exist tribal, state and local jurisdictions in the United States where we operate that also have, or are developing or considering developing, similar environmental and occupational health and safety laws and regulations governing many of these same types of activities. Any failure by us to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil, and criminal penalties; the imposition of investigatory, remedial, and corrective action obligations or the incurrence of capital expenditures; the occurrence of restrictions, delays or cancellations in the permitting, development or expansion of projects; and the issuance of injunctions restricting or prohibiting some or all of our activities in a particular area. Certain environmental laws also provide for citizen suits, which allow environmental organizations to act in place of the government and sue operators for alleged violations of environmental law. The ultimate financial impact arising from environmental laws and regulations is neither clearly known nor determinable as existing standards are subject to change and new standards continue to evolve.

We own, lease, or operate numerous properties that have been used for crude oil and natural gas midstream services for many years. Additionally, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or petroleum hydrocarbons was not under our control. Under environmental laws such as CERCLA and RCRA, we could incur strict joint and several liability for remediating hydrocarbons, hazardous substances or wastes disposed of or released by us or prior owners or operators. We also could incur costs related to the clean-up of third-party sites to which we sent regulated substances for disposal or to which we sent equipment for cleaning, and for damages to natural resources or other claims related to releases of regulated substances at or from such third-party sites.

Over time, the trend in environmental and occupational health and safety regulation is to typically place more restrictions and limitations on activities that may adversely affect the environment or expose workers to injury and thus, any changes in environmental or occupational health and safety laws and regulations or reinterpretation of enforcement policies that may arise in the future and result in more stringent or costly waste management or disposal, pollution control, remediation or occupational health and safety-related requirements could have a material adverse effect on our business, results of operations and financial position. We may not have insurance or be fully covered by insurance against all environmental and occupational health and safety risks, and we may be unable to pass on increased compliance costs arising out of such risks to our customers. We review regulatory and environmental issues as they pertain to us and we consider regulatory and environmental issues as part of our general risk management approach. For more information on environmental and occupational health and safety matters, see the following Risk Factors under Part I, Item 1A of this Form 10-K: "*Our operations are subject to environmental laws and regulations and a failure to comply or an accidental release into the environment may cause us to incur significant costs and liabilities,*" "*We could incur significant costs in complying with stringent occupational safety and health requirements,*" "*Laws and regulations regarding hydraulic fracturing could result in restrictions, delays or cancellations in drilling and completing new oil and natural gas wells by our customers, which could adversely impact our revenues by decreasing the volumes of natural gas, NGLs or crude oil through our facilities and reducing the utilization of our assets,*" and "*Our and our customers' operations are subject to a series of risks arising out of the threat of climate change (including legislation or regulation to address climate change) that could result in increased operating costs, limit the areas in which oil and natural gas production may occur, and reduce demand for the products and services we provide.*"

Pipeline Safety Matters

Many of our natural gas, NGL and crude oil pipelines are subject to regulation by the federal Pipeline and Hazardous Materials Safety Administration ("PHMSA"), an agency of the DOT, under the Natural Gas Pipeline Safety Act of 1968, as amended ("NGPSA"), with respect to natural gas, and the Hazardous Liquids Pipeline Safety Act of 1979, as amended ("HLPSA"), with respect to crude oil, NGLs and condensates. The NGPSA and HLPSA govern the design, installation, testing, construction, operation, replacement and management of natural gas, crude oil, NGL and condensate pipeline facilities. Pursuant to these acts, PHMSA has promulgated regulations governing, among other things, pipeline design, maximum operating pressures, pipeline patrols and leak surveys, public awareness, operation and maintenance procedures, operator qualification, minimum depth requirements and emergency procedures, as well as other matters intended to ensure adequate protection for the public and to prevent accidents and failures. Additionally, PHMSA has promulgated regulations requiring pipeline operators to develop and implement integrity management programs to comprehensively evaluate certain relatively higher risk areas, known as high consequence areas ("HCAs") and moderate consequence areas ("MCAs") along pipelines and take additional safety measures to protect people and property in these areas. The HCAs for natural gas pipelines are predicated on high-population areas (which, for natural gas transmission pipelines, may include Class 3 and Class 4 areas) whereas HCAs for crude oil, NGL and condensate pipelines is based on high-population areas, certain drinking water sources and unusually sensitive ecological areas. An MCA is attributable to natural gas pipelines and is based on high-population areas as well as certain principal, high-capacity roadways, though it does not meet the definition of a natural gas pipeline HCA. Various states have also adopted regulations, similar to existing PHMSA regulations for, and may have established agencies analogous to PHMSA to regulate, intrastate gathering and transmission lines. Historically, our pipeline safety compliance costs have not had a material adverse effect on our results of operations; however, there can be no assurance that such costs will not be material in the future or that such future compliance will not have a material adverse effect on our business, financial condition or results of operations. See Risk Factors "We may incur significant costs and liabilities resulting from performance of pipeline integrity programs and related repairs" and "Federal and state legislative and regulatory initiatives relating to pipeline safety that require the use of new or more stringent safety controls or result in more stringent enforcement of applicable legal requirements could subject us to increased capital costs, operational delays and costs of operation" under Item 1A of this Form 10-K for further discussion on pipeline safety standards, including integrity management requirements.

Title to Properties and Rights of Way

Our real property falls into two categories: (1) parcels that we own in fee and (2) parcels in which our interest derives from leases, easements, rights of way, permits or licenses from landowners or governmental authorities permitting the use of such land for our operations. Portions of the land on which our plants and other major facilities are located are owned by us in fee title and we believe that we have satisfactory title to these lands. The remainder of the land on which our plant sites and major facilities are located are held by us pursuant to ground leases between us, as lessee, and the fee owner of the lands, as lessors. We and our predecessors have leased these lands for many years without any material challenge known to us relating to the title to the land upon which the assets are located, and we believe that we have satisfactory leasehold estates to such lands. We have no knowledge of any challenge to the underlying fee title of any material lease, easement, rights of way, permit, lease or license, and we believe that we have satisfactory title to all of our material leases, easements, rights of way, permits, leases and licenses.

Employees

We do not have any employees. To carry out our operations, Targa employs approximately 2,680 people who primarily support our operations. None of those employees are covered by collective bargaining agreements. Targa considers its employee relations to be good.

Financial Information by Reportable Segment

See “Segment Information” included under Note 25 of the “Consolidated Financial Statements” for a presentation of financial results by reportable segment and see “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations–By Reportable Segment” for a discussion of our financial results by segment.

Available Information

We make certain filings with the SEC, including our Annual Report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments and exhibits to those reports. We make such filings available free of charge through our website, *http://www.targaresources.com*, as soon as reasonably practicable after they are filed with the SEC. Our press releases and recent analyst presentations are also available on our website. The SEC also maintains an internet website at *http://www.sec.gov* that contains reports, proxy and information statements and other information regarding issuers, including us, that file electronically with the SEC. The information contained on the websites referenced in this Annual Report on Form 10-K is not incorporated herein by reference.

Item 1A. Risk Factors.

Limited partner interests are inherently different from capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in similar businesses. The nature of our business activities subjects us to certain hazards and risks. You should consider carefully the following risk factors together with all the other information contained in this report. If any of the following risks were to occur, then our business, financial condition, cash flows and results of operations could be materially adversely affected.

We have a substantial amount of indebtedness which may adversely affect our financial position.

We have a substantial amount of indebtedness. As of December 31, 2019, we had $6,973.6 million outstanding of our senior unsecured notes and $54.6 million of outstanding senior notes of TPL, excluding $0.3 million of unamortized net discounts and premiums. We also had $370.0 million outstanding under our Securitization Facility. In addition, we had $88.2 million of letters of credit outstanding and $2,111.8 million of additional borrowing capacity available under the TRP Revolver. Our $2.2 billion TRP Revolver allows us to request increases in commitments up to an additional $500 million. For the years ended December 31, 2019, 2018 and 2017, our consolidated interest expense, net was $320.8 million, $170.0 million and $217.8 million.

In November 2019, we issued $1.0 billion of 5½% Senior Notes due March 2030, resulting in total net proceeds of approximately $990.8 million. The net proceeds from the issuance were used to repay borrowings under our credit facilities and for general partnership purposes.

This substantial level of indebtedness increases the possibility that we may be unable to generate cash sufficient to pay, when due, the principal of, interest on or other amounts due in respect of indebtedness. This substantial indebtedness, combined with lease and other financial obligations and contractual commitments, could have other important consequences to us, including the following:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;

- satisfying our obligations with respect to indebtedness may be more difficult and any failure to comply with the obligations of any debt instruments could result in an event of default under the agreements governing such indebtedness;

- we will need a portion of cash flow to make interest payments on debt, reducing the funds that would otherwise be available for operations and future business opportunities;

- our debt level may influence how counterparties view our creditworthiness, which could limit our ability to enter into commercial transactions at favorable rates or require us to post additional collateral in commercial transactions;

- our debt level will make us more vulnerable to competitive pressures or a downturn in our business or the economy generally; and

- our debt level may limit flexibility in planning for, or responding to, changing business and economic conditions.

Our long-term unsecured debt is currently rated by Standard & Poor's Corporation ("S&P") and Moody's Investors Service, Inc. ("Moody's"). As of December 31, 2019, Targa's senior unsecured debt was rated "BB" by S&P. As of December 31, 2019, Targa's senior unsecured debt was rated "Ba3" by Moody's. Any future downgrades in our credit ratings could negatively impact our cost of raising capital, and a downgrade could also adversely affect our ability to effectively execute aspects of our strategy and to access capital in the public markets.

Our ability to service our debt will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control. If our operating results are not sufficient to service our current or future indebtedness, we will be forced to take actions such as reducing or delaying business activities, acquisitions, investments or capital expenditures, selling assets, restructuring or refinancing debt, or seeking additional equity capital, and such results may adversely affect our ability to make cash distributions. We may not be able to affect any of these actions on satisfactory terms, or at all.

Despite current indebtedness levels, we may still be able to incur substantially more debt. This could increase the risks associated with compliance with our financial covenants.

We may be able to incur substantial additional indebtedness in the future. The TRP Revolver allows us to request increases in commitments up to an additional $500 million. Although our debt agreements contain restrictions on the incurrence of additional indebtedness, these restrictions are subject to a number of significant qualifications and exceptions, and any indebtedness incurred in compliance with these restrictions could be substantial. If we incur additional debt, this could increase the risks associated with compliance with our financial covenants.

Increases in interest rates could adversely affect our business.

We have significant exposure to increases in interest rates. As of December 31, 2019, our total indebtedness was $7,436.2 million, excluding $0.3 million of net premiums and $49.1 million of net debt issuance costs, of which $7,028.2 million was at fixed interest rates, $370.0 million was at variable interest rates and $38.0 million of finance lease liabilities. A one percentage point increase in the interest rate on our variable interest rate debt would have increased our consolidated annual interest expense by approximately $3.7 million based on our December 31, 2019 debt balances. As a result of this amount of variable interest rate debt, our results of operations could be adversely affected by increases in interest rates.

The terms of our debt agreements may restrict our current and future operations, particularly our ability to respond to changes in business or to take certain actions.

The agreements governing our outstanding indebtedness contain, and any future indebtedness we incur will likely contain, a number of restrictive covenants that impose significant operating and financial restrictions, including restrictions on our ability to engage in acts that may be in our best long-term interests. These agreements include covenants that, among other things, restrict our ability to:

- incur or guarantee additional indebtedness or issue additional preferred units;

- pay distributions on our equity securities or to our equity holders or redeem, repurchase or retire our equity securities or subordinated indebtedness;

- make investments and certain acquisitions;

- sell or transfer assets, including equity securities of our subsidiaries;

- engage in affiliate transactions,

- consolidate or merge;

- incur liens;

- prepay, redeem and repurchase certain debt, subject to certain exceptions;
- enter into sale and lease-back transactions or take-or-pay contracts; and
- change business activities conducted by us.

In addition, certain of our debt agreements require us to satisfy and maintain specified financial ratios and other financial condition tests. Our ability to meet those financial ratios and tests can be affected by events beyond our control, and we cannot assure you that we will meet those ratios and tests.

A breach of any of these covenants could result in an event of default under our debt agreements. Upon the occurrence of such an event of default, all amounts outstanding under the applicable debt agreements could be declared to be immediately due and payable and all applicable commitments to extend further credit could be terminated. For example, if we are unable to repay the accelerated debt under the TRP Revolver, the lenders under the TRP Revolver could proceed against the collateral granted to them to secure that indebtedness. If we are unable to repay the accelerated debt under the Securitization Facility, the lenders under the Securitization Facility could proceed against the collateral granted to them to secure the indebtedness. We have pledged the assets and equity of certain of our subsidiaries as collateral under the TRP Revolver and the accounts receivables of Targa Receivables LLC under the Securitization Facility. If the indebtedness under our debt agreements is accelerated, we cannot assure you that we will have sufficient assets to repay the indebtedness. The operating and financial restrictions and covenants in these debt agreements and any future financing agreements may adversely affect our ability to finance future operations or capital needs or to engage in other business activities.

Our cash flow is affected by supply and demand for natural gas, NGL products and crude oil and by natural gas, NGL, crude oil and condensate prices, and decreases in these prices could adversely affect our results of operations and financial condition.

Our operations can be affected by the level of natural gas, NGL and crude oil prices and the relationship between these prices. The prices of crude oil, natural gas and NGLs have been volatile, and we expect this volatility to continue. Our future cash flow may be materially adversely affected if we experience significant, prolonged price deterioration. The markets and prices for crude oil, natural gas and NGLs depend upon factors beyond our control. These factors include supply and demand for these commodities, which fluctuates with changes in market and economic conditions, and other factors, including:

- the impact of seasonality and weather;
- general economic conditions and economic conditions impacting our primary markets;
- the economic conditions of our customers;
- the level of domestic crude oil and natural gas production and consumption;
- the availability of imported natural gas, liquefied natural gas, NGLs and crude oil;
- actions taken by foreign oil and gas producing nations;
- the availability of local, intrastate and interstate transportation systems and storage for residue natural gas and NGLs;
- the availability and marketing of competitive fuels and/or feedstocks;
- the impact of energy conservation efforts;
- stockholder activism and activities by non-governmental organizations to limit certain sources of funding for the energy sector or restrict the exploration, development and production of oil and natural gas; and
- the extent of governmental regulation and taxation.

Our primary natural gas gathering and processing arrangements that expose us to commodity price risk are our percent-of-proceeds arrangements. Under these arrangements, we generally process natural gas from producers and remit to the producers an agreed percentage of the proceeds from the sale of residue gas and NGL products at market prices or a percentage of residue gas and NGL products at the tailgate of our processing facilities. In some percent-of-proceeds arrangements, we remit to the producer a percentage of an index-based price for residue gas and NGL products, less agreed adjustments, rather than remitting a portion of the actual sales proceeds. Under these types of arrangements, our revenues and cash flows increase or decrease, whichever is applicable, as the prices of natural gas, NGLs and crude oil fluctuate, to the extent our exposure to these prices is unhedged. See “Item 7A. Quantitative and Qualitative Disclosures About Market Risk.”

Changes in future business conditions could cause recorded long-lived assets to become further impaired, and our financial condition and results of operations could suffer if there is an additional impairment of property, plant and equipment assets.

We evaluate long-lived assets, including related intangibles, for impairment when events or changes in circumstances indicate, in management's judgment, that the carrying value of such assets may not be recoverable. Asset recoverability is measured by comparing the carrying value of the asset or asset group with its expected future pre-tax undiscounted cash flows. These cash flow estimates require us to make projections and assumptions for many years into the future for pricing, demand, competition, operating cost and other factors. Global oil and natural gas commodity prices, particularly crude oil, have declined substantially as compared to the peak of pricing in mid-2014 and remain volatile. Decreases in commodity prices have previously had, and could continue to have, a negative impact on the demand for our services and our market capitalization.

Should energy industry conditions deteriorate, there is a possibility that long-lived assets may be impaired in a future period. Any additional impairment charges that we may take in the future could be material to our financial statements. We cannot accurately predict the amount and timing of any impairment of long-lived assets. For a further discussion of our asset impairments, see Note 6 — Property, Plant and Equipment and Intangible Assets of the "Consolidated Financial Statements" included in this Annual Report.

We are exposed to credit risks of our customers, and any material nonpayment or nonperformance by our key customers could adversely affect our cash flow and results of operations.

Many of our customers may experience financial problems that could have a significant effect on their creditworthiness, especially in a depressed commodity price environment. A decline in natural gas, NGL and crude oil prices may adversely affect the business, financial condition, results of operations, creditworthiness, cash flows and prospects of some of our customers. Severe financial problems encountered by our customers could limit our ability to collect amounts owed to us, or to enforce performance of obligations under contractual arrangements. In addition, many of our customers finance their activities through cash flow from operations, the incurrence of debt or the issuance of equity. The combination of reduction of cash flow resulting from a decline in commodity prices, a reduction in borrowing bases under reserve-based credit facilities and the lack of availability of debt or equity financing may result in a significant reduction of our customers' liquidity and limit their ability to make payment or perform on their obligations to us. Additionally, a decline in the share price of some of our public customers may place them in danger of becoming delisted from a public securities exchange, limiting their access to the public capital markets and further restricting their liquidity. Furthermore, some of our customers may be highly leveraged and subject to their own operating and regulatory risks, which increases the risk that they may default on their obligations to us. To the extent one or more of our key customers is in financial distress or commences bankruptcy proceedings, contracts with these customers may be subject to renegotiation or rejection under applicable provisions of the United States Bankruptcy Code. Financial problems experienced by our customers could result in the impairment of our assets, reduction of our operating cash flows and may also reduce or curtail their future use of our products and services, which could reduce our revenues. Any material nonpayment or nonperformance by our key customers or our derivative counterparties could reduce our ability to make distributions to our unitholders.

Because of the natural decline in production in our operating regions and in other regions from which we source NGL supplies, our long-term success depends on our ability to obtain new sources of supplies of natural gas, NGLs and crude oil, which depends on certain factors beyond our control. Any decrease in supplies of natural gas, NGLs or crude oil could adversely affect our business and operating results.

Our gathering systems are connected to crude oil and natural gas wells from which production will naturally decline over time, which means that the cash flows associated with these sources of natural gas and crude oil will likely also decline over time. Our logistics assets are similarly impacted by declines in NGL supplies in the regions in which we operate as well as other regions from which we source NGLs. To maintain or increase throughput levels on our gathering systems and the utilization rate at our processing plants and our treating and fractionation facilities, we must continually obtain new natural gas, NGL and crude oil supplies. A material decrease in natural gas or crude oil production from producing areas on which we rely, as a result of depressed commodity prices or otherwise, could result in a decline in the volume of natural gas or crude oil that we process, NGL products delivered to our fractionation facilities or crude oil that we gather. Our ability to obtain additional sources of natural gas, NGLs and crude oil depends, in part, on the level of successful drilling and production activity near our gathering systems and, in part, on the level of successful drilling and production in other areas from which we source NGL and crude oil supplies. We have no control over the level of such activity in the areas of our operations, the amount of reserves associated with the wells or the rate at which production from a well will decline. In addition, we have no control over producers or their drilling, completion or production decisions, which are affected by, among other things, prevailing and projected energy prices, demand for hydrocarbons, the level of reserves, geological considerations, governmental regulations, the availability of drilling rigs, other production and development costs and the availability and cost of capital.

Fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new oil and natural gas reserves. Drilling and production activity generally decreases as crude oil and natural gas prices decrease. Prices of crude oil and natural gas have been historically volatile, and we expect this volatility to continue. Consequently, even if new natural gas or crude oil reserves are discovered in areas served by our assets, producers may choose not to develop those reserves. For example, current low prices for natural gas combined with relatively high levels of natural gas in storage could result in curtailment or shut-in of natural gas production. Reductions in exploration and production activity, competitor actions or shut-ins by producers in the areas in which we operate may prevent us from obtaining supplies of natural gas or crude oil to replace the natural decline in volumes from existing wells, which could result in reduced volumes through our facilities and reduced utilization of our gathering, treating, processing and fractionation assets.

If we do not make acquisitions or develop growth projects for expanding existing assets or constructing new midstream assets on economically acceptable terms, or fail to efficiently and effectively integrate acquired or developed assets with our asset base, our future growth will be limited. In addition, any acquisitions we complete are subject to substantial risks that could adversely affect our financial condition and results of operations and reduce our ability to make distributions to our limited partners. In addition, we may not achieve the expected results of any acquisitions and any adverse conditions or developments related to such acquisitions may have a negative impact on our operations and financial condition.

Our ability to grow depends, in part, on our ability to make acquisitions or develop growth projects that result in an increase in cash generated from operations. We are unable to acquire businesses from Targa in order to grow because Targa's only assets currently are the interests in us that Targa owns. As a result, we will need to focus on third-party acquisitions and organic growth. If we are unable to make accretive acquisitions or develop accretive growth projects because we are (1) unable to identify attractive acquisition candidates and negotiate acceptable acquisition agreements or develop growth projects economically, (2) unable to obtain financing for these acquisitions or projects on economically acceptable terms, or (3) unable to compete successfully for acquisitions or growth projects, then our future growth and ability to increase distributions will be limited.

Any acquisition or growth project involves potential risks, including, among other things:

- operating a significantly larger combined organization and adding new or expanded operations;
- difficulties in the assimilation of the assets and operations of the acquired businesses or growth projects, especially if the assets acquired are in a new business segment and/or geographic area;
- the risk that crude oil and natural gas reserves expected to support the acquired assets may not be of the anticipated magnitude or may not be developed as anticipated;
- the failure to realize expected volumes, revenues, profitability or growth;
- the failure to realize any expected synergies and cost savings;
- coordinating geographically disparate organizations, systems and facilities;
- the assumption of environmental and other unknown liabilities;
- limitations on rights to indemnity from the seller in an acquisition or the contractors and suppliers in growth projects;
- the failure to attain or maintain compliance with environmental and other governmental regulations;
- inaccurate assumptions about the overall costs of equity or debt;
- the diversion of management's and employees' attention from other business concerns;
- challenges associated with joint venture relationships and minority investments, including dependence on joint venture partners, controlling shareholders or management who may have business interests, strategies or goals that are inconsistent with ours; and
- customer or key employee losses at the acquired businesses or to a competitor.

If these risks materialize, any acquired assets or growth project may inhibit our growth, fail to deliver expected benefits and/or add further unexpected costs. Challenges may arise whenever businesses with different operations or management are combined, and we may experience unanticipated delays in realizing the benefits of an acquisition or growth project. If we consummate any future acquisition or growth project, our capitalization and results of operations may change significantly and you may not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in evaluating future acquisitions or growth projects.

Our acquisition and growth strategy is based, in part, on our expectation of ongoing divestitures of energy assets by industry participants and new opportunities created by industry expansion. A material decrease in such divestitures or in opportunities for economic commercial expansion would limit our opportunities for future acquisitions or growth projects and could adversely affect our operations and cash flows available for distribution to our limited partners.

Acquisitions may significantly increase our size and diversify the geographic areas in which we operate and growth projects may increase our concentration in a line of business or geographic region. We may not achieve the desired effect from any future acquisitions or growth projects.

Our expansion or modification of existing assets or the construction of new assets may not result in revenue increases and is subject to regulatory, environmental, political, legal and economic risks, which could adversely affect our results of operations and financial condition.

The construction of additions or modifications to our existing systems and the construction of new midstream assets involve numerous regulatory, environmental, political and legal uncertainties beyond our control and may require the expenditure of significant amounts of capital. If we undertake these projects, they may not be completed on schedule, at the budgeted cost or at all. For example, the construction of additional systems may be delayed or require greater capital investment if the commodity prices of certain supplies, such as steel pipe, increase due to imposed tariffs. Moreover, our revenues may not increase immediately upon the expenditure of funds on a particular project. For instance, if we build a new pipeline, fractionation facility or gas processing plant, the construction may occur over an extended period of time and we will not receive any material increases in revenues until the project is completed. Moreover, we may construct pipelines or facilities to capture anticipated future growth in production in a region in which such growth does not materialize. Since we are not engaged in the exploration for and development of natural gas and oil reserves, we do not possess reserve expertise and we often do not have access to third-party estimates of potential reserves in an area prior to constructing pipelines or facilities in such area. To the extent we rely on estimates of future production in any decision to construct additions to our systems, such estimates may prove to be inaccurate because there are numerous uncertainties inherent in estimating quantities of future production. As a result, new pipelines or facilities may not be able to attract enough throughput to achieve our expected investment return, which could adversely affect our results of operations and financial condition. In addition, the construction of additions to our existing gathering and transportation assets may require us to obtain new rights of way prior to constructing new pipelines. We may be unable to obtain or renew such rights of way to connect new natural gas and crude oil supplies to our existing gathering lines or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive for us to obtain new rights of way or to renew existing rights of way. If the cost of renewing or obtaining new rights of way increases, our cash flows could be adversely affected.

Our acquisition and growth strategy requires access to new capital. Tightened capital markets or increased competition for investment opportunities could impair our ability to grow through acquisitions or growth projects.

We continuously consider and enter into discussions regarding potential acquisitions and growth projects. Any limitations on our access to capital will impair our ability to execute this strategy. If the cost of such capital becomes too expensive, our ability to develop or acquire strategic and accretive assets will be limited. We may not be able to raise the necessary funds on satisfactory terms, if at all. The primary factors that influence our initial cost of equity include market conditions, fees we pay to underwriters and other offering costs, which include amounts we pay for legal and accounting services. The primary factors influencing our cost of borrowing include interest rates, credit spreads, covenants, underwriting or loan origination fees and similar charges we pay to lenders. These factors may impair our ability to execute our acquisition and growth strategy.

In addition, we are experiencing increased competition for the types of assets we contemplate purchasing or developing. Current economic conditions and competition for asset purchases and development opportunities could limit our ability to fully execute our acquisition and growth strategy.

If our general partner loses any of its named executive officers, our business may be adversely affected.

Our success is dependent upon the efforts of the named executive officers of our general partner. The named executive officers of our general partner are responsible for executing our business strategies. There is substantial competition for qualified personnel in the midstream oil and gas industry. Our general partner may not be able to retain its existing named executive officers or fill new positions or vacancies created by expansion or turnover. Our general partner has not entered into employment agreements with any of its named executive officers. In addition, it does not maintain “key man” life insurance on the lives of any of its named executive officers. A loss of one or more of the named executive officers of our general partner could harm our business and prevent us from implementing our business strategies.

We operate in areas of high industry activity, which may affect our ability to hire, train or retain qualified personnel needed to manage and operate our business.

We operate in areas in which industry activity has increased rapidly. As a result, demand for qualified personnel in these areas, particularly those related to our Permian and Badlands assets, and the cost to attract and retain such personnel, has increased over the past few years due to competition, and may increase substantially in the future. Moreover, our competitors may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer.

Any delay or inability to secure the personnel necessary for us to continue or complete our current and planned development projects, or any significant increases in costs with respect to the hiring, training or retention of qualified personnel, could have a material adverse effect on our business, financial condition and results of operations.

If we fail to maintain an effective system of internal controls, we may not be able to accurately report our financial results or prevent fraud. In addition, potential changes in accounting standards might cause us to revise our financial results and disclosure in the future.

Effective internal controls are necessary for us to provide timely and reliable financial reports and effectively prevent fraud. If we cannot provide timely and reliable financial reports or prevent fraud, our reputation and operating results would be harmed. We continue to enhance our internal controls and financial reporting capabilities. These enhancements require a significant commitment of resources, personnel and the development and maintenance of formalized internal reporting procedures to ensure the reliability of our financial reporting. Our efforts to update and maintain our internal controls may not be successful, and we may be unable to maintain adequate controls over our financial processes and reporting now or in the future, including future compliance with the obligations under Section 404 of the Sarbanes-Oxley Act of 2002.

Any failure to maintain effective controls or difficulties encountered in the effective improvement of our internal controls could prevent us from timely and reliably reporting our financial results and may harm our operating results. Ineffective internal controls could also cause investors to lose confidence in our reported financial information. In addition, the Financial Accounting Standards Board or the SEC could enact new accounting standards that might impact how we are required to record revenues, expenses, assets and liabilities. Any significant change in accounting standards or disclosure requirements could have a material effect on our results of operations, financial condition and ability to comply with our debt obligations.

If we fail to balance our purchases and sales of the commodities we handle, our exposure to commodity price risk will increase.

We may not be successful in balancing our purchases and sales of the commodities we handle. In addition, a producer could fail to deliver promised volumes to us or deliver in excess of contracted volumes, or a purchaser could purchase less than contracted volumes. Any of these actions could cause an imbalance between our purchases and sales. If our purchases and sales are not balanced, we will face increased exposure to commodity price risks and could have increased volatility in our operating income.

Our hedging activities may not be effective in reducing the variability of our cash flows and may, in certain circumstances, increase the variability of our cash flows. Moreover, our hedges may not fully protect us against volatility in basis differentials. Finally, the percentage of our expected equity commodity volumes that are hedged decreases substantially over time.

We have entered into derivative transactions related to only a portion of our equity volumes, future commodity purchases and sales, and transportation basis risk. As a result, we will continue to have direct commodity price risk to the unhedged portion. Our actual future volumes may be significantly higher or lower than we estimated at the time we entered into the derivative transactions for that period. If the actual amount is higher than we estimated, we will have greater commodity price risk than we intended. If the actual amount is lower than the amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale of the underlying physical commodity. The percentages of our expected equity volumes that are covered by our hedges decrease over time. To the extent we hedge our commodity price risk, we may forego the benefits we would otherwise experience if commodity prices were to change in our favor. The derivative instruments we utilize for these hedges are based on posted market prices, which may be higher or lower than the actual natural gas, NGL and condensate prices that we realize in our operations. These pricing differentials may be substantial and could materially impact the prices we ultimately realize. Market and economic conditions may adversely affect our hedge counterparties’ ability to meet their obligations. Given volatility in the financial and commodity markets, we may experience defaults by our hedge counterparties. In addition, our exchange traded futures are subject to margin requirements, which creates variability in our cash flows as commodity prices fluctuate.

As a result of these and other factors, our hedging activities may not be as effective as we intend in reducing the variability of our cash flows, and in certain circumstances may actually increase the variability of our cash flows. See “Item 7A. Quantitative and Qualitative Disclosures About Market Risk.”

If third-party pipelines and other facilities interconnected to our natural gas and crude oil gathering systems, terminals and processing facilities become partially or fully unavailable to transport natural gas, NGLs and crude oil, our revenues could be adversely affected.

We depend upon third-party pipelines, storage and other facilities that provide delivery options to and from our gathering and processing facilities. Since we do not own or operate these pipelines or other facilities, their continuing operation in their current manner is not within our control. If any of these third-party facilities become partially or fully unavailable, or if the quality specifications for their facilities change so as to restrict our ability to utilize them, our revenues could be adversely affected.

Our industry is highly competitive, and increased competitive pressure could adversely affect our business and operating results.

We compete with similar enterprises in our respective areas of operation. Some of our competitors are large crude oil, natural gas and NGL companies that have greater financial resources and access to supplies of natural gas, NGLs and crude oil than we do. Some of these competitors may expand or construct gathering, processing, storage, terminaling and transportation systems that would create additional competition for the services we provide to our customers. In addition, customers who are significant producers of natural gas may develop their own gathering, processing, storage, terminaling and transportation systems in lieu of using those operated by us. Our ability to renew or replace existing contracts with our customers at rates sufficient to maintain current revenues and cash flows could be adversely affected by the activities of our competitors and our customers. All of these competitive pressures could have a material adverse effect on our business, results of operations and financial condition.

We typically do not obtain independent evaluations of natural gas or crude oil reserves dedicated to our gathering pipeline systems; therefore, supply volumes on our systems in the future could be less than we anticipate.

We typically do not obtain independent evaluations of natural gas or crude oil reserves connected to our gathering systems due to the unwillingness of producers to provide reserve information as well as the cost of such evaluations. Accordingly, we do not have independent estimates of total reserves dedicated to our gathering systems or the anticipated life of such reserves. If the total reserves or estimated life of the reserves connected to our gathering systems is less than we anticipate and we are unable to secure additional sources of supply, then the volumes of natural gas or crude oil transported on our gathering systems in the future could be less than we anticipate. A decline in the volumes on our systems could have a material adverse effect on our business, results of operations and financial condition.

A reduction in demand for NGL products by the petrochemical, refining or other industries or by the fuel or export markets, or a significant increase in NGL product supply relative to this demand, could materially adversely affect our business, results of operations and financial condition.

The NGL products we produce have a variety of applications, including as heating fuels, petrochemical feedstocks and refining blend stocks. A reduction in demand for NGL products, whether because of general or industry-specific economic conditions, new government regulations, global competition, reduced demand by consumers for products made with NGL products (for example, reduced petrochemical demand observed due to lower activity in the automobile and construction industries), reduced demand for propane or butane exports whether for price or other reasons, increased competition from petroleum-based feedstocks due to pricing differences, mild winter weather for some NGL applications or other reasons, could result in a decline in the volume of NGL products we handle or reduce the fees we charge for our services. Also, increased supply of NGL products could reduce the value of NGLs handled by us and reduce the margins realized. Our NGL products and their demand are affected as follows:

Ethane. Ethane is typically supplied as purity ethane and as part of an ethane-propane mix. Ethane is primarily used in the petrochemical industry as feedstock for ethylene, one of the basic building blocks for a wide range of plastics and other chemical products. Although ethane is typically extracted as part of the mixed NGL stream at gas processing plants, if natural gas prices increase significantly in relation to NGL product prices or if the demand for ethylene falls, it may be more profitable for natural gas processors to leave the ethane in the natural gas stream, thereby reducing the volume of NGLs delivered for fractionation and marketing.

Propane. Propane is used as a petrochemical feedstock in the production of ethylene and propylene, as a heating, engine and industrial fuel, and in agricultural applications such as crop drying. Changes in demand for ethylene and propylene could adversely affect demand for propane. The demand for propane as a heating fuel is significantly affected by weather conditions. The volume of propane sold is increasingly driven by international exports supplying a growing global demand for the product. Domestically in the U.S., propane is at its highest during the six-month peak heating season of October through March. Demand for our propane may be reduced during periods of slow global economic growth and warmer-than-normal weather.

Normal Butane. Normal butane is used in the production of isobutane, as a refined petroleum product blending component, as a fuel gas (either alone or in a mixture with propane) and in the production of ethylene and propylene. Changes in the composition of refined petroleum products resulting from governmental regulation, changes in feedstocks, products and economics, and demand for heating fuel, ethylene and propylene could adversely affect demand for normal butane. The volume of butane sold is increasingly driven by international exports supplying a growing demand for the product.

Isobutane. Isobutane is predominantly used in refineries to produce alkylates to enhance octane levels. Accordingly, any action that reduces demand for motor gasoline or demand for isobutane to produce alkylates for octane enhancement might reduce demand for isobutane.

Natural Gasoline. Natural gasoline is used as a blending component for certain refined petroleum products and as a feedstock used in the production of ethylene and propylene. Changes in the mandated composition of motor gasoline resulting from governmental regulation, and in demand for ethylene and propylene, could adversely affect demand for natural gasoline.

NGLs and products produced from NGLs also compete with products from global markets. Any reduced demand or increased supply for ethane, propane, normal butane, isobutane or natural gasoline in the markets we access for any of the reasons stated above could adversely affect both demand for the services we provide and NGL prices, which could negatively impact our results of operations and financial condition.

We do not own most of the land on which our pipelines, terminals and compression facilities are located, which could disrupt our operations.

We do not own most of the land on which our pipelines, terminals and compression facilities are located, and we are therefore subject to the possibility of more onerous terms and/or increased costs to retain necessary land use if we do not have valid rights of way or leases or if such rights of way or leases lapse or terminate. We sometimes obtain the rights to land owned by third parties and governmental agencies for a specific period of time. Additionally, the federal Tenth Circuit Court of Appeals has held that tribal ownership of even a very small fractional interest in an allotted land, that is, tribal land owned or at one time owned by an individual Indian landowner, bars condemnation of any interest in the allotment. Consequently, the inability to condemn such allotted lands under circumstances where an existing pipeline rights of way may soon lapse or terminate serves as an additional impediment for pipeline operators. We cannot guarantee that we will always be able to renew existing rights of way or obtain new rights of way without experiencing significant costs. Any loss of rights with respect to our real property, through our inability to renew rights of way contracts or leases, or otherwise, could cause us to cease operations on the affected land, increase costs related to continuing operations elsewhere and reduce our revenue.

We may be unable to cause our majority-owned joint ventures to take or not to take certain actions unless some or all of our joint venture participants agree and certain of our joint venture partners may fail or refuse to fund their respective portions of capital projects that we believe are necessary to expand or maintain such joint venture's business.

We participate in several majority-owned joint ventures whose corporate governance structures require at least a majority in interest vote to authorize many basic activities and require a greater voting interest (sometimes up to 100%) to authorize more significant activities. Examples of these more significant activities include, among others, large expenditures or contractual commitments, the construction or acquisition of assets, borrowing money or otherwise raising capital, making distributions, transactions with affiliates of a joint venture participant, litigation and transactions not in the ordinary course of business. Without the concurrence of joint venture participants with enough voting interests, we may be unable to cause any of our joint ventures to take or not take certain actions, even though taking or preventing those actions may be in our best interests or the particular joint venture.

Certain of our joint venture partners may fail, refuse or elect not to fund their respective portions of capital projects that we believe are necessary to effectively expand or maintain such joint venture's business. Such failure or election not to fund may impact the operations of the joint venture and may increase the capital that could be required from us if we were to fund such projects without the full participation of our joint venture partners. We may not achieve an acceptable rate of return for any such additional expenditures.

In addition, subject to certain conditions, any joint venture owner may sell, transfer or otherwise modify its ownership interest in a joint venture, whether in a transaction involving third parties or the other joint owners. Any such transaction could result in our partnering with different or additional parties.

We may operate a portion of our business with one or more joint venture partners where we own a minority interest and/or are not the operator, which may restrict our operational and corporate flexibility. Actions taken by the other partner or third-party operator may materially impact our financial position and results of operations, and we may not realize the benefits we expect to realize from a joint venture.

As is common in the midstream industry, we may operate one or more of our properties with one or more joint venture partners where we own a minority interest and/or contract with a third party to control operations. These relationships could require us to share operational and other control, such that we may no longer have the flexibility to control completely the development of these properties. If we do not timely meet our financial commitments in such circumstances, our rights to participate may be adversely affected. If a joint venture partner is unable or fails to pay its portion of development costs or if a third-party operator does not operate in accordance with our expectations, our costs of operations could be increased. We could also incur liability as a result of actions taken by a joint venture partner or third-party operator. Disputes between us and the other party may result in litigation or arbitration that would increase our expenses, delay or terminate projects and distract our officers and directors from focusing their time and effort on our business.

Weather may limit our ability to operate our business and could adversely affect our operating results.

The weather in the areas in which we operate can cause disruptions and in some cases suspension of our operations and development activities. For example, unseasonably wet weather, extended periods of below freezing weather, or hurricanes may cause a loss of throughput from temporary cessation of activities or lost or damaged equipment. Our planning for normal climatic variation, insurance programs and emergency recovery plans may inadequately mitigate the effects of such weather conditions, and not all such effects can be predicted, eliminated or insured against. Some forecasters expect that potential climate changes may have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events and could have an adverse effect on our operations. Any unusual or prolonged severe weather or increased frequency thereof, such as freezing rain, earthquakes, hurricanes, droughts, or floods in our or our oil and gas exploration and production customers' areas of operations or markets, whether due to climate change or otherwise, could have a material adverse effect on our business, results of operations and financial condition.

Rising sea levels, subsidence and erosion could damage our pipelines and the facilities that serve our customers, particularly along the Gulf Coast and offshore, which could adversely affect our business, results of operations and financial condition.

Our operations along the Gulf Coast and offshore could be impacted by rising sea levels, subsidence and erosion. Subsidence issues are also a concern for our pipelines at major river crossings. Rising sea levels, subsidence and erosion could cause serious damage to our pipelines and other facilities, which could affect our ability to provide services or result in leakage, migration, releases or spills from our operations to surface or subsurface soils, surface water, groundwater or to the Gulf of Mexico, which could result in liability, remedial obligations and/or otherwise have a negative impact on continued operations. Additionally, such rising sea levels, subsidence and erosion processes could impact our oil and gas exploration and production customers who operate along the Gulf Coast, and they may be unable to utilize our services. Rising sea levels, subsidence and erosion could also expose our operations to increased risks associated with severe weather conditions and other adverse events and conditions, such as hurricanes and flooding. As a result, we may incur significant costs to repair and preserve our pipeline infrastructure and other facilities. Such costs could adversely affect our business, financial condition, results of operations and cash flows. In addition, local governments and landowners have filed lawsuits in recent years in Louisiana against energy companies, alleging that their operations contributed to increased coastal rising seas and erosion and seeking substantial damages.

Our business involves many hazards and operational risks, some of which may not be insured or fully covered by insurance. If a significant accident or event occurs for which we are not fully insured, if we fail to recover all anticipated insurance proceeds for significant accidents or events for which we are insured, or if we fail to rebuild facilities damaged by such accidents or events, our operations and financial results could be adversely affected.

Our operations are subject to many hazards inherent in gathering, compressing, treating, processing and selling natural gas; storing, fractionating, treating, transporting and selling NGLs and NGL products; gathering, storing and terminaling crude oil; and storing and terminaling refined petroleum products, including:

- damage to pipelines and plants, related equipment and surrounding properties caused by hurricanes, tornadoes, floods, fires and other natural disasters, explosions and acts of terrorism;
- inadvertent damage from third parties, including from motor vehicles and construction, farm or utility equipment;
- damage that is the result of our negligence or any of our employees' negligence;
- leaks of natural gas, NGLs, crude oil and other hydrocarbons or losses of natural gas or NGLs as a result of the malfunction of equipment or facilities;
- spills or other unauthorized releases of natural gas, NGLs, crude oil, other hydrocarbons or waste materials that contaminate the environment, including soils, surface water and groundwater, and otherwise adversely impact natural resources; and
- other hazards that could also result in personal injury, loss of life, pollution and/or suspension of operations.

These risks could result in substantial losses due to personal injury, loss of life, severe damage to and destruction of property and equipment, and pollution or other environmental or natural resource damage, and may result in delay, curtailment or suspension of our related operations. A natural disaster or other hazard affecting the areas in which we operate could have a material adverse effect on our operations. We are not fully insured against all risks inherent to our business. Additionally, while we are insured for pollution resulting from environmental accidents that occur on a sudden and accidental basis, we may not be insured against all environmental accidents that might occur, some of which may result in toxic tort claims. If a significant accident or event occurs that is not fully insured, if we fail to recover all anticipated insurance proceeds for significant accidents or events for which we are insured, or if we fail to rebuild facilities damaged by such accidents or events, our operations and financial condition could be adversely affected. In addition, we may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. As a result of market conditions, premiums and deductibles for certain of our insurance policies have increased substantially, and could escalate further. For example, following Hurricanes Katrina and Rita, insurance premiums, deductibles and co-insurance requirements increased substantially, and terms were generally less favorable than terms that could be obtained prior to such hurricanes. Insurance market conditions worsened as a result of the losses sustained from Hurricanes Gustav and Ike. As a result, we experienced further increases in deductibles and premiums, and further reductions in coverage and limits, with some coverage unavailable at any cost.

Unexpected volume changes due to production variability or to gathering, plant or pipeline system disruptions may increase our exposure to commodity price movements.

We sell processed natural gas at plant tailgates or at pipeline pooling points. Sales made to natural gas marketers and end-users may be interrupted by disruptions to volumes anywhere along the system. We attempt to balance sales with volumes supplied from processing operations, but unexpected volume variations due to production variability or to gathering, plant or pipeline system disruptions may expose us to volume imbalances which, in conjunction with movements in commodity prices, could materially impact our income from operations and cash flow.

Our operations are subject to environmental laws and regulations and a failure to comply or an accidental release into the environment may cause us to incur significant costs and liabilities.

Our operations are subject to numerous federal, tribal, state and local environmental laws and regulations governing occupational health and safety, the discharge of pollutants into the environment or otherwise relating to environmental protection. These laws and regulations may impose numerous obligations that are applicable to our operations including acquisition of a permit or other approval before conducting regulated activities, restrictions on the types, quantities and concentration of materials that can be released into the environment; limitation or prohibition of construction and operating activities in environmentally sensitive areas such as wetlands, urban areas, wilderness regions and other protected areas; requiring capital expenditures to comply with pollution control requirements, and imposition of substantial liabilities for pollution resulting from our operations. Numerous governmental authorities, such as the EPA and BLM, and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits and approvals issued under them, which can often require difficult and costly actions. Failure to comply with these laws and regulations or any newly adopted laws or regulations may result in assessment of sanctions including administrative, civil and criminal penalties, the imposition of investigatory, remedial and corrective action obligations or the incurrence of capital expenditures; the occurrence of restrictions, delays or cancellations in the permitting or performance of projects, and the issuance of orders enjoining or conditioning performance of some or all of our operations in a particular area. Certain environmental laws impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances, hydrocarbons or waste products have been released, even under circumstances where the substances, hydrocarbons or wastes have been released by a predecessor operator or the activities conducted and from which a release emanated complied with applicable law. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by noise, odor, or the release of hazardous substances, hydrocarbons or wastes into the environment.

The risk of incurring environmental costs and liabilities in connection with our operations is significant due to our handling of natural gas, NGLs, crude oil and other petroleum products, because of air emissions and product-related discharges arising out of our operations, and as a result of historical industry operations and waste disposal practices. For example, an accidental release from one of our facilities could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury, natural resource and property damages and fines or penalties for related violations of environmental laws or regulations.

Moreover, stricter laws, regulations or enforcement policies could significantly increase our operational or compliance costs and the cost of any remediation that may become necessary. For example, in 2015, the EPA issued a final rule under the CAA, lowering the National Ambient Air Quality Standard ("NAAQS") for ground-level ozone to 70 parts per billion under both the primary and secondary standards to provide requisite protection of the public health and welfare. Since that time, the EPA has issued area designations with respect to ground-level ozone and final requirements that apply to state, local and tribal air agencies for implementing the 2015 NAAQS for ground-level ozone. Also in 2015, the EPA and U.S. Army Corps of Engineers ("Corps") under the Obama administration released a final rule outlining federal jurisdictional reach under the Clean Water Act over waters of the United States, including wetlands. In 2017, the EPA and the Corps under the Trump administration agreed to reconsider the 2015 rule and, thereafter, on October 22, 2019, the agencies published a final rule made effective on December 23, 2019, rescinding the 2015 rule and re-codifying the regulatory text that governed waters of the United States prior to promulgation of the 2015 rule until such time as a final rule re-defining the Clean Water Act's jurisdiction over water of the United States was made effective in replacement of the 2015 rule. On January 23, 2020, the two agencies issued a final rule re-defining such jurisdiction. Upon being published in the Federal Register and the passage of 60 days thereafter, the January 23, 2020 final rule will become effective in replacement of the October 22, 2019 final rule. Under the new January 23, 2020 final rule, the EPA has narrowed the federal government's jurisdictional permitting authority under the Clean Water Act relative to the 2015 final rule. The 2015 final rule has been the subject of legal challenges by various factions in federal district court and implementation of the 2015 rule has been enjoined in slightly over half of the states pending resolution of the various federal district court challenges. Upon the effectiveness of the January 23, 2020 rule, the United States will be covered under a single regulatory scheme as it relates to federal jurisdictional reach over waters of the United States. However, there remains the expectation that the January 23, 2020 final rule also will be legally challenged in federal district court. To the extent that any challenge to the January 23, 2020 final rule is successful and the 2015 rule or a revised rule expands the scope of the Clean Water Act's jurisdiction in areas where we or our customers conduct operations, such developments could delay, restrict or halt the development of projects, result in longer permitting timelines, or increased compliance expenditures or mitigation costs for our and our oil and natural gas customers' operations, which may reduce the rate of production of natural gas or crude oil from operators with whom we have a business relationship and, in turn, have a material adverse effect on our business, results of operations and cash flows.

We could incur significant costs in complying with stringent occupational safety and health requirements.

We are subject to stringent federal and state laws and regulations, including the federal Occupational Safety and Health Act and comparable state statutes, whose purpose is to protect the health and safety of workers, both generally and within the pipeline industry. In addition, the federal Occupational Safety and Health Administration's ("OSHA") hazard communication standard, the EPA community right-to-know regulations under Title III of the Federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We and the entities in which we own an interest are subject to OSHA Process Safety Management regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. The regulations apply to any process that (1) involves a listed chemical in a quantity at or above the threshold quantity specified in the regulation for that chemical, or (2) involves certain flammable gases or flammable liquids present on site in one location in a quantity of 10,000 pounds or more. Flammable liquids stored in atmospheric tanks below their normal boiling point without the benefit of chilling or refrigeration are exempt. Failure to comply with these laws and regulations or any newly adopted laws or regulations may result in assessment of sanctions including administrative, civil and criminal penalties, the imposition of investigatory, remedial and corrective action obligations or the incurrence of capital expenditures, any of which could have a material adverse effect on our business, financial condition and results of operations.

Laws and regulations regarding hydraulic fracturing could result in restrictions, delays or cancellations in drilling and completing new oil and natural gas wells by our customers, which could adversely impact our revenues by decreasing the volumes of natural gas, NGLs or crude oil through our facilities and reducing the utilization of our assets.

While we do not conduct hydraulic fracturing, many of our oil and gas exploration and production customers do perform such activities. Hydraulic fracturing is a process used by oil and natural gas exploration and production operators in the completion of certain oil and natural gas wells whereby water, sand or alternative proppant, and chemical additives are injected under pressure into subsurface formations to stimulate the flow of certain oil and natural gas, increasing the volumes that may be recovered. The process is typically regulated by state oil and gas commissions, but several federal agencies have asserted regulatory authority over, proposed or promulgated regulations governing, and conducted investigations relating to certain aspects of the process, including the EPA. For example, in late 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources, concluding that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources under certain circumstances. In addition, Congress has from time to time considered the adoption of legislation to provide for federal regulation of hydraulic fracturing. Additionally, certain candidates seeking the office of President of the United States in 2020 have pledged to ban hydraulic fracturing of oil and natural gas wells. Moreover, some states have adopted, and others are considering adopting, legal requirements that could impose more stringent permitting, disclosure or well construction requirements on hydraulic fracturing activities, assess more taxes, fees or royalties on natural gas production, or otherwise limit the use of the technique. For example, in April 2019, the Governor of Colorado signed Senate Bill 19-181 into law, which legislation, among other things, revises the mission of the state oil and gas agency from fostering energy development in the state to instead focusing on regulating the industry in a manner that is protective of public health and safety and the environment, as well as authorizing cities and counties to regulate oil and natural gas operations within their jurisdiction as they do other developments. States could elect to prohibit hydraulic fracturing or high volume hydraulic fracturing altogether, following the approach taken by states of Vermont, Maryland, and New York. Local governments may also seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. Additionally, non-governmental organizations may seek to restrict hydraulic fracturing; notwithstanding the adoption of Colorado Senate Bill 19-181 in 2019, one or more interest groups in the state have already filed new ballot initiatives with the state in January 2020, in hopes of extending drilling setbacks from oil and natural gas development. New or more stringent laws, regulations or regulatory or ballot initiatives relating to the hydraulic fracturing process could lead to our customers reducing crude oil and natural gas drilling activities using hydraulic fracturing techniques, while increased public opposition to activities using such techniques may result in operational delays, restrictions, cessations, or increased litigation. Any one or more of such developments could reduce demand for our gathering, processing and fractionation services and have a material adverse effect on our business, financial condition and results of operations.

A change in the jurisdictional characterization of some of our assets by federal, state, tribal or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase or delay or increase the cost of expansion projects.

With the exception of the Driver Residue Pipeline, TPL SouthTex Transmission pipeline and Tarzan 311 residue line, which are each subject to limited FERC regulation under either the NGA or NGPA, our natural gas pipeline operations are generally exempt from FERC regulation, but FERC regulation still affects our non-FERC jurisdictional businesses and the markets for products derived from these businesses, including certain FERC reporting and posting requirements in a given year. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of substantial, ongoing litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress. We also operate natural gas pipelines that extend from some of our processing plants to interconnections with both intrastate and interstate natural gas pipelines. Those facilities, known in the industry as "plant tailgate" pipelines, typically operate at transmission pressure levels and may transport "pipeline quality" natural gas. Because our plant tailgate pipelines are relatively short, we treat them as "stub" lines, which are exempt from FERC's jurisdiction under the Natural Gas Act.

Targa NGL and Grand Prix Joint Venture have pipelines that are considered common carrier pipelines subject to regulation by FERC under ICA. The ICA requires that we maintain tariffs on file with FERC for each of the Targa NGL and Grand Prix Joint Venture pipelines that have not been granted a waiver. Those tariffs set forth the rates we charge for providing transportation services as well as the rules and regulations governing these services. The ICA requires, among other things, that rates on interstate common carrier pipelines be "just and reasonable" and non-discriminatory. With respect to pipelines that have been granted a waiver of the ICA and related regulations by FERC, should a particular pipeline's circumstances change, FERC could, either at the request of other entities or on its own initiative, assert that such pipeline no longer qualifies for a waiver. In the event that FERC were to determine that one or more of these pipelines no longer qualified for a waiver, we would likely be required to file a tariff with FERC for the applicable pipeline(s), provide a cost justification for the transportation charge, and provide service to all potential shippers without undue discrimination. Such a change in the jurisdictional status of transportation on these pipelines could adversely affect our results of operations.

In addition, the courts have determined that certain pipelines that would otherwise be subject to the ICA are exempt from regulation by FERC under the ICA as proprietary lines. The classification of a line as a proprietary line is a fact-based determination subject to FERC and court review. Accordingly, the classification and regulation of some of our gathering facilities and transportation pipelines may be subject to change based on future determinations by FERC, the courts or Congress, in which case, our operating costs could increase and we could be subject to enforcement actions under the EP Act of 2005.

Various federal agencies within the U.S. Department of the Interior, particularly the BLM, Office of Natural Resources Revenue (formerly the Minerals Management Service) and the Bureau of Indian Affairs, along with the Three Affiliated Tribes, promulgate and enforce regulations pertaining to operations on the Fort Berthold Indian Reservation, on which we operate a significant portion of our Badlands gathering and processing assets. The Three Affiliated Tribes is a sovereign nation having the right to enforce certain laws and regulations independent from federal, state and local statutes and regulations. These tribal laws and regulations include various taxes, fees and other conditions that apply to lessees, operators and contractors conducting operations on Native American tribal lands. Lessees and operators conducting operations on tribal lands can generally be subject to the Native American tribal court system. One or more of these factors may increase our costs of doing business on the Fort Berthold Indian Reservation and may have an adverse impact on our ability to effectively transport products within the Fort Berthold Indian Reservation or to conduct our operations on such lands.

Other FERC regulations may indirectly impact our businesses and the markets for products derived from these businesses. FERC's policies and practices across the range of its natural gas regulatory activities, including, for example, its policies on open access transportation, gas quality, ratemaking, capacity release and market center promotion, may indirectly affect the intrastate natural gas market. In recent years, FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines. However, we cannot assure you that FERC will continue this approach as it considers matters such as pipeline rates and rules and policies that may affect rights of access to transportation capacity. For more information regarding the regulation of our operations, see "Item 1. Business—Regulation of Operations."

Should we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

Under the EP Act of 2005, FERC has civil penalty authority under the NGA and NGPA to impose penalties for violations of the NGA or NGPA, respectively, up to approximately $1.29 million (adjusted annually for inflation) per day for each violation and disgorgement of profits associated with any violation. While our systems other than the Driver Residue Pipeline, TPL SouthTex Transmission pipeline and Tarzan 311 residue line, have not been regulated by FERC under the NGA or NGPA, FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional facilities to FERC annual reporting and daily scheduled flow and capacity posting requirements. Additional rules and legislation pertaining to those and other matters may be considered or adopted by FERC from time to time. Failure to comply with those regulations in the future could subject us to civil penalty liability. In addition, FERC has civil penalty authority under the ICA to impose penalties for violations under the ICA of up to approximately $13,500 per violation per day, and failure to comply with the ICA and regulations implementing the ICA could subject us to civil penalty liability. For more information regarding regulation of our operations, see "Item 1. Business—Regulation of Operations."

Our and our customers' operations are subject to a number of risks arising out of the threat of climate change (including legislation or regulation to address climate change) that could result in increased operating costs, limit the areas in which oil and natural gas production may occur, and reduce demand for the products and services we provide.

The threat of climate change continues to attract considerable attention in the United States and in foreign countries. As a result, numerous proposals have been made and could continue to be made at the international, national, regional and state levels of government to monitor and limit existing emissions of GHGs as well as to restrict or eliminate such future emissions. As a result, our operations as well as the operations of our oil and natural gas exploration and production customers are subject to a series of regulatory, political, litigation, and financial risks associated with the production and processing of fossil fuels and emission of GHGs.

In the United States, no comprehensive climate change legislation has been implemented at the federal level. However, because the U.S. Supreme Court has held that GHG emissions constitute a pollutant under the CAA, the EPA has adopted rules that, among other things, establish construction and operating permit reviews for GHG emissions from certain large stationary sources, require the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources, implement New Source Performance Standards directing the reduction of methane from certain new, modified, or reconstructed facilities in the oil and natural gas sector, and together with the DOT, implement GHG emissions limits on vehicles manufactured for operation in the United States. Additionally, various states and groups of states have adopted or are considering adopting legislation, regulations or other regulatory initiatives that are focused on such areas as GHG cap and trade programs, carbon taxes, reporting and tracking programs, and restriction of emissions. At the international level, there exists the United Nations-sponsored "Paris Agreement," which is a non-binding agreement for nations to limit their GHG emissions through individually-determined reduction goals every five years beginning in 2020, although the United States has announced its withdrawal from such agreement, effective November 4, 2020.

Governmental, scientific, and public concern over the threat of climate change arising from GHG emissions has resulted in increasing political risks in the United States, in the form of pledges made by certain candidates seeking the office of the President of the United States in 2020. Critical declarations made by one or more presidential candidates include proposals to ban hydraulic fracturing of oil and natural gas wells and banning new leases for production of minerals on federal properties, including onshore lands and offshore waters. Other actions to oil and natural gas production activities that could be pursued by presidential candidates may include more restrictive requirements for the establishment of pipeline infrastructure or the permitting of liquefied natural gas export facilities, as well as the rescission of the United States' withdrawal from the Paris Agreement in November 2020. Litigation risks are also increasing, as a number of cities, local governments, and other plaintiffs have sought to bring suit against the largest oil and natural gas exploration and production companies in state or federal court, alleging, among other things, that such companies created public nuisances by producing fuels that contributed to global warming effects, such as rising sea levels, and therefore are responsible for roadway and infrastructure damages as a result, or alleging that the companies have been aware of the adverse effects of climate change for some time but defrauded their investors by failing to adequately disclose those impacts.

There are also increasing financial risks for fossil fuel producers as well as other companies handling fossil fuels, including owners of terminals, pipelines and refineries, as stockholders and bondholders currently invested in fossil fuel energy companies concerned about the potential effects of climate change may elect in the future to shift some or all of their investments into non-fossil fuel energy related sectors. Institutional investors who provide financing to fossil fuel energy companies also have become more attentive to sustainability lending practices and some of them may elect not to provide funding for fossil fuel energy companies. Additionally, the lending and investment practices of institutional lenders have been the subject of intensive lobbying efforts in recent years, oftentimes public in nature, by environmental activists, proponents of the international Paris Agreement, and foreign citizenry concerned about climate change not to provide funding for fossil fuel producers. Limitation of investments in and financings for fossil fuel energy companies could result in the restriction, delay, or cancellation of drilling programs or development of production activities.

The adoption and implementation of any international, federal or state legislation, regulations or other regulatory initiatives that impose more stringent standards for GHG emissions from the oil and natural gas sector or otherwise restrict the areas in which this sector may produce oil and natural gas or generate GHG emissions could result in increased costs of compliance or costs of consuming, and thereby reduce demand for oil and natural gas, which could reduce demand for our services and products. Additionally, political, litigation, and financial risks may result in our oil and natural gas customers restricting or cancelling production activities, incurring liability for infrastructure damages as a result of climatic changes, or impairing their ability to continue to operate in an economic manner, which also could reduce demand for our services and products. One or more of these developments could have a material adverse effect on our business, financial condition and results of operation. Finally, increasing concentrations of GHG in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods, rising sea levels and other climatic events. If any such climate changes were to occur, they could have an adverse effect on our financial condition and results of operations and the financial condition and operations of our customers.

Federal and state legislative and regulatory initiatives relating to pipeline safety that require the use of new or more stringent safety controls or result in more rigorous enforcement of applicable legal requirements could subject us to increased capital costs, operational delays and costs of operation.

In 2016, President Obama signed the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016 (“2016 Pipeline Safety Act”) that extended PHMSA’s statutory mandate regarding pipeline safety until September 30, 2019 and required PHMSA to complete certain of its outstanding mandates under the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (“2011 Pipeline Safety Act”). The 2011 Pipeline Safety Act had directed the promulgation of regulations relating to such matters as expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation, testing to confirm the material strength of certain pipelines and operator verification of records confirming the maximum allowable pressure of certain intrastate gas transmission pipelines. The 2016 Pipeline Safety Act also empowered PHMSA to address unsafe conditions or practices constituting imminent hazards by imposing emergency restrictions, prohibitions and safety measures on owners and operators of gas or hazardous liquid pipeline facilities without prior notice or an opportunity for a hearing. On October 1, 2019, PHMSA published a final rule that replaced a 2016 interim rule, implementing the agency’s expanded authority relating to imminent hazards to life, property or the environment.

The imposition of new safety enhancement requirements pursuant to the 2016 Pipeline Safety Act and the 2011 Pipeline Safety Act or any issuance or reinterpretation of guidance by PHMSA or any state agencies with respect thereto could require us to install new or modified safety controls, pursue additional capital projects or conduct maintenance programs on an accelerated basis, any or all of which tasks could result in our incurring increased operating costs that could have a material adverse effect on our results of operations or financial position.

Additionally, PHMSA and one or more state regulators, including the RRC, have in recent years expanded the scope of their regulatory inspections to include certain in-plant equipment and pipelines found within NGL fractionation facilities and associated storage facilities, to assess compliance with hazardous liquids pipeline safety requirements. To the extent that PHMSA and/or state regulatory agencies are successful in asserting their jurisdiction in this manner, we and other midstream operators of NGL fractionation facilities and associated storage facilities may be required to make operational changes or modifications at their facilities to meet standards beyond current OSHA PSM and EPA RMP requirements, which changes or modifications may result in additional capital costs, possible operational delays and increased costs of operation that, in some instances, may be significant.

We may incur significant costs and liabilities resulting from performance of pipeline integrity programs and related repairs.

Pursuant to the authority under the NGPSA and HLPSA, PHMSA has established a series of rules requiring pipeline operators to develop and implement integrity management programs for certain natural gas and hazardous liquids pipelines that, in the event of a pipeline leak or rupture could affect higher risk areas, known as HCAs and MCAs, which are areas where a release could have the most significant adverse consequences. The HCAs for natural gas pipelines are predicated on high-population areas (which, for natural gas transmission pipelines, may include Class 3 and Class 4 areas) whereas HCAs for crude oil, NGL and condensate pipelines is based on high-population areas, certain drinking water sources and unusually sensitive ecological areas. An MCA is attributable to natural gas pipelines and is based on high-population areas as well as certain principal, high-capacity roadways, though it does not meet the definition of a natural gas pipeline HCA. Among other things, these regulations require operators of covered pipelines to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact an HCA or MCA;
- maintain processes for data collection, integration and analysis;
- repair and remediate pipelines as necessary; and
- implement preventive and mitigating actions.

In addition, certain states, including Texas, Louisiana, Oklahoma, New Mexico, and North Dakota, where we conduct operations, have adopted regulations similar to existing PHMSA regulations for certain intrastate natural gas and hazardous liquids pipelines. We currently estimate an average annual cost of $3.8 million between 2020 and 2022 to implement pipeline integrity management program testing along certain segments of our natural gas and hazardous liquids pipelines. This estimate does not include the costs, if any, of repair, remediation or preventative or mitigative actions that may be determined to be necessary as a result of the discovery of anomaly conditions during the testing program, which costs could be substantial. At this time, we cannot predict the ultimate cost of compliance with applicable pipeline integrity management regulations, as the cost will vary significantly depending on the number and extent of any repairs found to be necessary as a result of the pipeline integrity testing. We plan to continue our pipeline integrity testing programs to assess and maintain the integrity of our pipelines. The results of these tests could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines.

Moreover, changes to pipeline safety laws by Congress and regulations by PHMSA that result in more stringent or costly safety standards could have a significant adverse effect on us and similarly situated midstream operators. For instance, in 2016, pursuant to one of the requirements in the 2011 Pipeline Safety Act, PHMSA published a proposed rulemaking that would expand integrity management requirements and impose new pressure testing requirements on currently regulated natural gas pipelines. The proposal would also significantly expand the regulation of gathering lines, subjecting previously unregulated pipelines to requirements regarding damage prevention, corrosion control, public education programs, maximum allowable operating pressure limits and other requirements. However, PHMSA has since decided to split its 2016 proposed rule, which has become known as the "gas Mega Rule," into three separate rulemakings to facilitate completion. The first of these three rulemakings, relating to onshore gas transmission pipelines, was published as a final rule on October 1, 2019, becomes effective on July 1, 2020, and imposes numerous requirements on such pipelines, including maximum allowable operating pressure ("MAOP") reconfirmation, the assessment of additional pipeline mileage outside of HCAs (including all MCAs and those Class 3 and Class 4 areas found not to be in HCAs) within 14 years of publication date and at least once every 10 years thereafter, the reporting of exceedances of MAOP, and the consideration of seismicity as a risk factor in integrity management. The remaining rulemakings comprising the gas mega rule are expected to be issued in 2020. Additionally, on October 1, 2019, PHMSA published a final rule for hazardous liquid transmission and gathering pipelines that becomes effective July 1, 2020 and significantly extends and expands the reach of certain PHMSA integrity management requirements, regardless of the pipeline's proximity to an HCA (for example, integrity assessments at least once every 10 years of onshore, piggable, hazardous liquid pipeline segments located outside of HCAs, and expanded use of leak detection systems beyond HCAs to all regulated hazardous liquid pipelines other than offshore gathering and regulated rural gathering pipelines). The final rule also requires all hazardous liquid pipelines in or affecting an HCA to be capable of accommodating in-line inspection tools within the next 20 years unless the basic construction of a pipeline cannot be modified to permit that accommodation. In addition, the final rule extends annual, accident, and safety-related conditional reporting requirements to hazardous liquid gravity lines and certain gathering lines and also imposes inspection requirements on hazardous liquid pipelines in areas affected by extreme weather events and natural disasters, such as hurricanes, landslides, floods, earthquakes or other similar events that are likely to damage infrastructure.

Congress subsequently enacted the 2016 Pipeline Safety Act, which reauthorized PHMSA's hazardous liquid and gas pipeline programs through September 30, 2019, and thus it is expected that Congress will issue an updated pipeline safety law in 2019 or 2020 that will reauthorize those programs through 2023. The integrity-related requirements and other provisions of the 2011 Pipeline Safety Act, the 2016 Pipeline Safety Act, and any new Congressional pipeline safety legislation that is expected to be introduced to reauthorize PHMSA pipeline safety programs, as well as any implementation of PHMSA rules thereunder, could require us to pursue additional capital projects or conduct integrity or maintenance programs on an accelerated basis and incur increased operating costs that could have a material adverse effect on our costs of transportation services as well as our business, results of operations and financial condition.

Portions of our pipeline systems may require increased expenditures for maintenance and repair owing to the age of some of our systems, which expenditures or resulting loss of revenue due to pipeline age or condition could have a material adverse effect on our business and results of operations.

Some portions of the pipeline systems that we operate have been in service for several decades prior to our purchase of them. Consequently, there may be historical occurrences or latent issues regarding our pipeline systems that our executive management may be unaware of and that may have a material adverse effect on our business and results of operations. The age and condition of some of our pipeline systems could also result in increased maintenance or repair expenditures, and any downtime associated with increased maintenance and repair activities could materially reduce our revenue. Any significant increase in maintenance and repair expenditures or loss of revenue due to the age or condition of some portions of our pipeline systems could adversely affect our business and results of operations.

The implementation of derivatives legislation could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"), enacted on July 21, 2010, established federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The Dodd-Frank Act required the CFTC and the SEC to promulgate rules and regulations implementing the Dodd-Frank Act. Although the CFTC has finalized most of these regulations, others remain to be finalized or implemented and it is not possible at this time to predict when this will be accomplished.

In January 2020, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain *bona fide* hedging transactions. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time.

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing and the associated rules also will require us, in connection with covered derivative activities, to comply with clearing and trade-execution requirements or take steps to qualify for an exemption to such requirements. Although we qualify for the end-user exception from the mandatory clearing requirements for swaps entered to hedge our commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. The CFTC and the federal banking regulators have adopted regulations requiring certain counterparties to swap to post initial and variation margin. However, our current hedging activities would qualify for the non-financial end user exemption from the margin requirements.

The full impact of the Dodd-Frank Act and related regulatory requirements upon our business will not be known until all of the regulations are implemented and the market for derivatives contracts has adjusted. The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts or increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations implementing the Dodd-Frank Act, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures.

Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and implementing regulations is to lower commodity prices.

Any of these consequences could have a material adverse effect on us, our financial condition and our results of operations.

The European Union (the "EU") and other non-U.S. jurisdictions are also implementing regulations with respect to the derivatives market. To the extent we enter into swaps with counterparties in foreign jurisdictions or counterparties with other businesses that subject them to regulation in foreign jurisdictions, we may become subject to or otherwise impacted by such regulations. As is the case with the Dodd-Frank Act and the regulations promulgated under it, the implementing regulations adopted by the EU and by other non-U.S. jurisdictions could have an adverse effect on us, our financial condition and our results of operations.

Terrorist attacks and the threat of terrorist attacks have resulted in increased costs to our business. Continued hostilities in the Middle East or other sustained military campaigns may adversely impact our results of operations.

The long-term impact of terrorist attacks, such as the attacks that occurred on September 11, 2001, and the threat of future terrorist attacks on our industry in general and on us in particular is not known at this time. However, resulting regulatory requirements and/or related business decisions associated with security are likely to increase our costs.

Increased security measures taken by us as a precaution against possible terrorist attacks have resulted in increased costs to our business. Uncertainty surrounding continued hostilities in the Middle East or other sustained military campaigns may affect our operations in unpredictable ways, including disruptions of crude oil supplies and markets for our products, and the possibility that infrastructure facilities could be direct targets, or indirect casualties, of an act of terror.

Changes in the insurance markets attributable to terrorist attacks may make certain types of insurance more difficult for us to obtain. Moreover, the insurance that may be available to us may be significantly more expensive than our existing insurance coverage or coverage may be reduced or unavailable. Instability in the financial markets as a result of terrorism or war could also affect our ability to raise capital.

We face opposition to operation and expansion of our pipelines and facilities from various individuals and groups.

We have experienced, and we anticipate that we will encounter from time to time, opposition to the operation and expansion of our pipelines and facilities from governmental officials, non-governmental environmental organizations and groups, landowners, tribal groups, local groups and other advocates. In some instances, we encounter opposition which disfavors hydrocarbon-based energy supplies regardless of practical implementation or financial considerations. Opposition to our operation and expansion can take many forms, including the delay, denial or termination of required governmental permits or approvals, organized protests, attempts to block or sabotage our operations, intervention in regulatory or administrative proceedings involving our assets or lawsuits or other actions designed to prevent, disrupt, delay or terminate the operation or expansion of our assets and business. In addition, destructive forms of protest or opposition by activists, including acts of sabotage or eco terrorism could cause significant damage or injury to people, property or the environment or lead to extended interruptions of our operations. Any such event that restricts, delays or prevents the expansion of our business, interrupts the revenues generated by our operations or causes us to make significant expenditures not covered by insurance could adversely affect our business, results of operations, and financial condition.

We are subject to cyber security risks. A cyber incident could occur and result in information theft, data corruption, operational disruption and/or financial loss.

The oil and natural gas industry has become increasingly dependent on digital technologies to conduct business. For example, we depend on digital technologies to operate our facilities, serve our customers and record financial data. At the same time, cyber incidents, including deliberate attacks, have increased. The U.S. government has issued public warnings that indicate that energy assets might be specific targets of cyber security threats. Our technologies, systems and networks, and those of our vendors, suppliers, customers and other business partners, may become the target of cyberattacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or could adversely disrupt our business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period. Our systems for protecting against cyber security risks may not be sufficient. As cyber incidents continue to evolve, we will likely be required to expend additional resources to enhance our security posture and cybersecurity defenses or to investigate and remediate any vulnerability to or consequences of cyber incidents. Our insurance coverages for cyberattacks may not be sufficient to cover all the losses we may experience as a result of a cyber incident.

We are or may become subject to cybersecurity and data privacy laws, regulations, litigation and directives relating to our processing of personal information.

The jurisdictions in which we operate (including the United States) may have laws governing how we must respond to a cyber incident that results in the unauthorized access, disclosure, or loss of personal information. Additionally, new laws and regulations governing data privacy and unauthorized disclosure of confidential information, including recent California legislation (which, among other things, provides for a private right of action), pose increasingly complex compliance challenges and could potentially elevate our costs over time. Although our business does not involve large-scale processing of personal information, our business does involve collection, use, and other processing of personal information of our employees, investors, contractors, suppliers, and customer contacts. As legislation continues to develop and cyber incidents continue to evolve, we will likely be required to expend significant resources to continue to modify or enhance our protective measures to comply with such legislation and to detect, investigate and remediate vulnerabilities to cyber incidents. Any failure by us, or a company we acquire, to comply with such laws and regulations could result in reputational harm, loss of goodwill, penalties, liabilities, and/or mandated changes in our business practices.

Risks Related to Our Structure

Targa owns and controls our general partner, which has sole responsibility for conducting our business and managing our operations. Targa has conflicts of interest with us and may favor its own interests to your detriment.

All of our general partner’s directors and all of its executive officers are directors or officers of Targa. Therefore, conflicts of interest may arise between Targa, including our general partner, on the one hand, and us and our limited partners, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests over the interests of our limited partners. These conflicts include, among others, the following situations:

- neither our partnership agreement nor any other agreement requires Targa to pursue a business strategy that favors us. Targa’s directors and officers have a fiduciary duty to make decisions in the best interests of the owners of Targa, which may be contrary to our interests; and

- our general partner is allowed to take into account the interests of parties other than us, such as Targa or its owners, in resolving conflicts of interest.

Targa is not limited in its ability to compete with us and is under no obligation to offer assets it may acquire to us, which could limit our ability to acquire additional assets or businesses.

Our partnership agreement does not prohibit Targa from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, Targa may acquire, construct or dispose of additional midstream or other assets in the future, without any obligation to offer us the opportunity to purchase or construct any of those assets. As a result, competition from Targa could adversely impact our results of operations and cash available for distribution.

The credit and business risk profile of our general partner could adversely affect our credit ratings and profile.

The credit and business risk profiles of our general partner may be factors in credit evaluations of us. This is because our general partner can exercise significant influence over our business, including our cash distribution and acquisition strategy and business risk profile. Another factor that may be considered is the financial condition of our general partner, including the degree of its financial leverage and its dependence on cash flow from us to service its indebtedness.

Targa, the owner of our general partner and all of our common units, is dependent on the cash distributions from its indirect general partner and limited partner equity interests in us to provide working capital. Any distributions by us to such entities will be made only after satisfying our then-current obligations to our creditors. Our credit ratings and business risk profile could be adversely affected if the ratings and risk profiles of the entities that control our general partner were viewed as substantially lower or more risky than ours.

Our partnership agreement limits our general partner's fiduciary duties to our limited partners and restricts the remedies available to limited partners for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

The directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner beneficial to its owner, Targa. Our partnership agreement contains provisions that reduce the standards to which our general partner would otherwise be held by state fiduciary duty laws. For example, our partnership agreement:

- permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of or factors affecting us;

- provides that our general partner does not have any liability to us or our limited partners for decisions made in its capacity as a general partner so long as it acted in good faith, meaning it believed the decision was in the best interests of our partnership;

- generally provides that affiliated transactions and resolutions of conflicts of interest not approved by the conflicts committee of the board of directors of our general partner acting in good faith and not involving a vote of limited partners must be on terms no less favorable to us than those generally being provided to or available from unrelated third parties, or must be "fair and reasonable" to us, as determined by our general partner in good faith, and that, in determining whether a transaction or resolution is "fair and reasonable," our general partner may consider the totality of the relationships between the parties involved, including other transactions that may be particularly advantageous or beneficial to us;

- provides that our general partner and its officers and directors are not liable for monetary damages to us, our limited partners or assignees for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our general partner or those other persons acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal; and

- provides that in resolving conflicts of interest, it is presumed that in making its decision our general partner acted in good faith, and in any proceeding brought by or on behalf of any limited partner or us, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Your liability may not be limited if a court finds that limited partner action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to our general partner. Our partnership is organized under Delaware law and we conduct business in Louisiana, Texas, Oklahoma and North Dakota as well as other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the states in which we do business. You could be liable for any and all of our obligations as if you were a general partner if a court or government agency determined that we were conducting business in a state but had not complied with that particular state's partnership statute; or that your right to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitute "control" of our business.

Limited partners may have liability to repay distributions that were wrongfully distributed to them.

Under certain circumstances, limited partners may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act, we may not make a distribution to limited partners if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of the impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Substituted limited partners are liable for the obligations of the assignor to make contributions to the partnership that are known to the substituted limited partner at the time it became a limited partner and for unknown obligations if the liabilities could be determined from the partnership agreement. Liabilities to partners on account of their partnership interest and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

Risks Related to the Preferred Units

We cannot assure you that we will be able to pay distributions on our Preferred Units regularly, and the agreements governing our indebtedness may limit the cash available to make distributions on the Preferred Units.

Subject to the limitations on restricted payments contained in our indentures and in our senior secured credit agreement, we distribute all of our "available cash" each quarter to our limited partners and our general partner. "Available cash" is defined in our partnership agreement and described below under "Item 5. Market for Registrant's Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities—Distributions of Available Cash—Definition of Available Cash." As a result, we do not expect to accumulate significant amounts of cash. Depending on the timing and amount of our cash distributions, these distributions could significantly reduce the cash available to us in subsequent periods to make payments on the Preferred Units.

The Preferred Units are subordinated to our existing and future debt obligations, and could be diluted by the issuance of additional units, including additional Preferred Units, and by other transactions.

The Preferred Units are subordinated to all of our existing and future indebtedness (including indebtedness outstanding under our senior secured credit facility, our existing senior notes and indebtedness outstanding under our Securitization Facility). The payment of principal and interest on our debt reduces cash available for distribution to us and on our units, including the Preferred Units. The issuance of additional units pari passu with or senior to the Preferred Units would dilute the interests of the holders of the Preferred Units, and any issuance of Senior Securities or Parity Securities (each as defined in our partnership agreement) or additional indebtedness could affect our ability to pay distributions on, redeem or pay the liquidation preference on the Preferred Units.

Our ability to issue parity securities in the future could adversely affect the rights of holders of our Preferred Units.

We are allowed to issue additional Preferred Units and parity securities without any vote of the holders of the Preferred Units, except where the cumulative distributions on the Preferred Units or any parity securities are in arrears. The issuance of additional Preferred Units or any parity securities would have the effect of reducing the amounts available to the holders of the outstanding Preferred Units upon our liquidation, dissolution or winding up if we do not have sufficient funds to pay all liquidation preferences of the Preferred Units and parity securities in full. It also would reduce amounts available to make distributions on the outstanding Preferred Units if we do not have sufficient funds to pay distributions on all outstanding Preferred Units and parity securities.

In addition, although holders of Preferred Units are entitled to limited voting rights, with respect to certain matters the Preferred Units will generally vote separately as a class along with all other series of our parity securities that we may issue upon which like voting rights have been conferred and are exercisable. As a result, the voting rights of holders of Preferred Units may be significantly diluted, and the holders of such other series of Parity Securities that we may issue may be able to control or significantly influence the outcome of any vote. Future issuances and sales of parity securities, or the perception that such issuances and sales could occur, may cause prevailing market prices for the Preferred Units to decline and may adversely affect our ability to raise additional capital in the financial markets at times and prices favorable to us.

Tax Risks to Holders of Preferred Units

Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes as well as our not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service ("IRS") were to treat us as a corporation for U.S. federal income tax purposes or if we were to become subject to a material amount of entity-level taxation for state tax purposes, then our cash available for distribution to you may be substantially reduced.

A publicly traded partnership such as us may be treated as a corporation for U.S. federal income tax purposes unless it satisfies the "qualifying income" requirement within Section 7704(d)(1)(E) of the Internal Revenue Code. Based on our current operations and current Treasury Regulations, we believe that we satisfy the qualifying income requirement and will be treated as a partnership. Failing to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for U.S.

federal income tax purposes or otherwise subject us to taxation as an entity. We have not requested, and do not plan to request, a ruling from the IRS with respect to our treatment as a partnership for U.S. federal income tax purposes.

If we were treated as a corporation for U.S. federal income tax purposes, we would pay U.S. federal income tax on our taxable income at the corporate tax rate, which is 21% for tax years beginning after December 31, 2017, and would likely pay state income tax at varying rates. Distributions to you would generally be taxed again as corporate distributions instead of as guaranteed payments for the use of capital, as described further below. Because a tax would be imposed upon us as a corporation, our cash available for distribution to you may be substantially reduced. Therefore, the treatment of us as a corporation may result in a material reduction in the anticipated cash flow.

At the state level, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income and franchise taxes and other forms of taxation. For example, we are subject to the Texas franchise tax at a maximum effective rate of 0.75% of our gross income apportioned to Texas in the prior year.

Holders of Preferred Units should consult their tax advisor with respect to the consequences of owning our Preferred Units.

The tax treatment of publicly traded partnerships or an investment in our Preferred Units could be subject to potential legislative, judicial or administrative changes or differing interpretations, possibly applied on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in us, may be modified by administrative, legislative or judicial changes or differing interpretations at any time. From time to time, members of Congress propose and consider such substantive changes to the existing U.S. federal income tax laws that would affect publicly traded partnerships, including elimination of partnership tax treatment for certain publicly traded partnerships. For example, the "Clean Energy for America Act," which is similar to legislation that was commonly proposed during the Obama Administration, was introduced in the U.S. Senate on May 2, 2019. If enacted, this proposal would, among other things, repeal the qualifying income exception within Section 7704(d)(1)(E) of the Internal Revenue Code upon which we rely for our treatment as a partnership for U.S. federal income tax purposes. In addition, the Treasury Department has issued, and in the future may issue, regulations interpreting those laws that affect publicly traded partnerships. There can be no assurance that there will not be further changes to U.S. federal income tax laws or the Treasury Department's interpretation of the qualifying income rules in a manner that could impact our ability to qualify as a partnership for U.S. federal income tax purposes in the future.

Any modification to the U.S. federal income tax laws or interpretations thereof may be applied retroactively and could make it more difficult or impossible for us to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Any such future changes could negatively impact the value of an investment in us. You are urged to consult with your own tax advisor with respect to the status of regulatory, legislative or administrative developments and proposals and their potential effect on your investment in our Preferred Units.

The tax treatment of income attributable to distributions on our Preferred Units as guaranteed payments for the use of capital is uncertain and such distributions will not be eligible for the 20% deduction.

The tax treatment of distributions on our Preferred Units is uncertain. We will treat the holders of Preferred Units as partners for tax purposes and will treat income attributable to distributions on the Preferred Units as guaranteed payments for the use of capital that will generally be taxable to the holders of Preferred Units as ordinary income. We anticipate accruing and making guaranteed payment distributions on a monthly basis. However, the accrual of such a guaranteed payment is not contingent upon a cash distribution, and holders of Preferred Units will recognize taxable income from such accrual even in the absence of a contemporaneous cash distribution. Otherwise, the holders of Preferred Units are generally neither anticipated to share in our items of income, gain, loss or deduction, nor be allocated any share of our nonrecourse liabilities. If the Preferred Units were treated as payments on indebtedness for tax purposes, rather than as guaranteed payments for the use of capital, distributions likely would be treated as payments of interest by us to the holders of Preferred Units.

Recently issued final Treasury Regulations provide that income attributable to a guaranteed payment for the use of capital is not eligible for the 20% deduction. As a result income attributable to a guaranteed payment for use of capital recognized by holders of our Preferred Units is not eligible for the 20% deduction.

Tax-exempt entities and non-U.S. persons face unique tax issues from owning our Preferred Units that may result in adverse tax consequences to them.

Investment in the Preferred Units by tax-exempt investors, such as employee benefit plans and individual retirement accounts ("IRAs"), and non-U.S. persons raises issues unique to them. Although the issue is not free from doubt, we will treat distributions to non-U.S. holders of the Preferred Units as "effectively connected income" (which will subject holders to U.S. net income taxation and possibly the branch profits tax) that are subject to withholding taxes imposed at the highest effective tax rate applicable to such non-U.S. holders. If the amount of withholding exceeds the amount of U.S. federal income tax actually due, non-U.S. holders may be required to file U.S. federal income tax returns in order to seek a refund of such excess. Non-U.S. holders of Preferred Units who sell or otherwise dispose of a Preferred Unit will also be subject to U.S. federal income tax on the gain realized from the sale or disposition of that Preferred Unit. The transferee of an interest in a partnership that is engaged in a U.S. trade or business is generally required to withhold 10% of the amount realized by the transferor unless the transferor certifies that it is not a foreign person, and we are required to deduct and withhold from the transferee amounts that should have been withheld by the transferees but were not withheld. However, pending the issuance of final regulations, the IRS has suspended the application of this withholding rule to transfers of publicly traded interests in publicly traded partnerships. If recently promulgated regulations are finalized as proposed, such regulations would provide, with respect to transfers of publicly traded interests in publicly traded partnerships effected through a broker, that the obligation to withhold is imposed on the transferor's broker. However, it is not clear when such regulations will be finalized and if they will be finalized in their current form.

Furthermore, the treatment of guaranteed payments for the use of capital to tax-exempt investors is not certain and such payments may be treated as unrelated business taxable income, or UBTI, for federal income tax purposes. With respect to taxable years beginning after December 31, 2017, subject to the proposed aggregation rules for certain similarly situated businesses or activities issued by the Treasury Department, a tax-exempt entity with more than one unrelated trade or business (including by attribution from investment in a partnership such as ours) is required to compute the unrelated business taxable income of such tax-exempt entity separately with respect to each such trade or business (including for purposes of determining any net operating loss deduction). As a result, for years beginning after December 31, 2017, it may not be possible for tax-exempt entities to utilize losses from an investment in our partnership to offset unrelated business taxable income from another unrelated trade or business and vice versa.

If you are a tax-exempt entity or a non-U.S. person, you should consult your tax advisor with respect to the consequences of owning our Preferred Units.

If the IRS contests the U.S. federal income tax positions we take, the market for our Preferred Units may be adversely affected and the cost of any contest will reduce our cash available for distribution to you. The Bipartisan Budget Act of 2015 alters the procedures for assessing and collecting taxes due for taxable years beginning after December 31, 2017, in a manner that could substantially reduce cash available for distribution to you.

We have not requested, and do not plan to request, a ruling from the IRS with respect to our treatment as a partnership for U.S. federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our Preferred Units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our partners because the costs will reduce our cash available for distribution.

The Bipartisan Budget Act of 2015, which is applicable to us for taxable years beginning after December 31, 2017, alters the procedures for auditing large partnerships and also alters the procedures for assessing and collecting taxes due (including applicable penalties and interest) as a result of an audit. Unless we are eligible to (and choose to) elect to issue revised information statements to our partners with respect to an audited and adjusted return, the IRS may assess and collect taxes (including any applicable penalties and interest) directly from us in the year in which the audit is completed under the new rules. If we are required to pay taxes, penalties and interest as the result of audit adjustments, cash available for distribution to our partners may be substantially reduced. In addition, because payment would be due for the taxable year in which the audit is completed, partners during that taxable year would bear the expense of the adjustment even if they were not unitholders during the audited taxable year.

A holder of Preferred Units whose units are the subject of a securities loan (e.g., a loan to cover a short sale of units) may be considered to have disposed of those units. If so, such holder of Preferred Units may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and could recognize gain or loss from the disposition.

Because there are no specific rules governing the federal tax consequences of loaning a partnership interest, a holder of Preferred Units whose units are the subject of a securities loan may be considered to have disposed of the loaned units. In that case the holder may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan, and the holder may recognize gain or loss from such disposition. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan of their units are urged to consult a tax advisor to determine whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

You may be subject to state and local taxes and return filing requirements in jurisdictions where you do not live as a result of investing in our Preferred Units.

In addition to federal income taxes, holders of Preferred Units may be subject to return filing requirements and other taxes, including state, local and non-U.S. income taxes, unincorporated business taxes, and estate, inheritance or intangible taxes that may be imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if they do not live in any of those jurisdictions. Moreover, we may also own property or do business in other states in the future that impose income or similar taxes on nonresident individuals. You may be subject to penalties for failure to comply with return filing requirements. It is your responsibility to file all U.S. federal, foreign, state and local tax returns and pay any taxes due in these jurisdictions. You should consult with your own tax advisors regarding the filing of such tax returns, the payment of such taxes, and the deductibility of any taxes paid.

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

A description of our properties is contained in “Item 1. Business” in this Annual Report.

Our principal executive offices are located at 811 Louisiana Street, Suite 2100, Houston, Texas 77002 and our telephone number is 713-584-1000.

Item 3. 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 II, Item 8 of this Annual Report, which is incorporated by reference into this item.

Item 4. Mine Safety Disclosures.

Not applicable.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

Market Information

On February 17, 2016, TRC completed the TRC/TRP Merger, pursuant to which TRC acquired indirectly all of our outstanding common units that TRC and its subsidiaries did not already own. Pursuant to the TRC/TRP Merger Agreement, TRC agreed to cause our common units under the symbol "NGLS" to be delisted from the NYSE and deregistered under the Exchange Act. As a result of the completion of the TRC/TRP Merger, our common units are no longer publicly traded. The Preferred Units remain outstanding as limited partner interests in us and continue to trade on the NYSE under the symbol "NGLS/PA."

There is no established trading market for the 5,629,136 general partner units held only by our general partner.

Distributions of Available Cash

General

As a result of the TRC/TRP Merger, Targa owns all of our outstanding common units. We have discretion under the Third A&R Partnership Agreement as to whether to distribute all available cash for any period. See Note 10 – Debt Obligations and Note 13 – Partnership Units and Related Matters of the "Consolidated Financial Statements" included in this Annual Report.

Definition of Available Cash

Under the partnership agreement, the term "available cash," is defined, for any quarter or month, as applicable, as the sum of all cash and cash equivalents on hand at the end of that quarter or month, as applicable, and all additional cash and cash equivalents on hand immediately prior to the date of the distribution of available cash resulting from borrowings for working capital purposes subsequent to the end of that quarter or month, as applicable, less the amount of any cash reserves established by our general partner to:

- provide for the proper conduct of our business (including reserves for future capital expenditures and for anticipated future credit needs);
- comply with applicable law or any loan agreements, security agreements, mortgages, debt instruments or other agreements;
- provide funds for distributions on and redemptions with respect to the Preferred Units; or
- provide funds for further distributions.

The amount of distributions paid under our policy and the decision to make any distribution is determined by our general partner, taking into consideration the terms of our partnership agreement. The board of directors of our general partner has broad discretion to establish cash reserves that it determines are necessary or appropriate to properly conduct our business, including reserves to provide funds for distributions on and redemptions with respect to the Preferred Units. These can also include cash reserves for future capital and maintenance expenditures, reserves to stabilize distributions of cash to our unitholders, reserves to reduce debt or, as necessary, reserves to comply with the terms of any of our agreements or obligations. We will be prohibited from making any distributions to unitholders if it would cause an event of default or if an event of default exists under our credit agreement or indentures.

Preferred Units

Distributions on the Preferred Units are cumulative from the date of original issue 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 our general partner. Distributions on the Preferred Units will be paid out of amounts legally available therefor to, but not including, November 1, 2020, 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%. For the year ended December 31, 2019, we have paid $11.3 million in distributions to the holders of our Preferred Units. See Note 13 - Partnership Units and Related Matters of the "Consolidated Financial Statements" included in this Annual Report.

Recent Sales of Unregistered Equity Securities

There were no sales of unregistered equity securities for the year ended December 31, 2019.

Repurchase of Equity by Targa Resources Partners LP or Affiliated Purchasers

None.

Item 6. Selected Financial Data.

The following table presents selected historical consolidated financial and operating data of Targa Resources Partners LP for the periods ended, and as of, the dates indicated. We derived this information from our historical "Consolidated Financial Statements" and accompanying notes. The information in the table below should be read together with, and is qualified in its entirety by reference to, those financial statements and notes in this Annual Report.

	2019	2018	2017	2016	2015
	(In millions, except per unit amounts)				
Statement of operations data:					
Revenues (1)	$ 8,671.1	$ 10,484.0	$ 8,814.9	$ 6,690.9	$ 6,658.6
Income (loss) from operations	206.1	253.6	(109.4)	66.0	167.4
Net income (loss)	(15.6)	98.6	(250.6)	(228.7)	(59.3)
Balance sheet data (at end of period):					
Total assets (2)	$ 18,744.5	$ 16,890.1	$ 14,359.0	$ 12,744.9	$ 13,126.8
Long-term debt (2)	7,005.2	5,197.4	4,268.0	4,177.0	5,125.7
Other:					
Distributions declared per unit	(3)	(3)	(3)	(3)	$ 3.3000

(1) Revenues for 2019 and 2018 include the impact of the adoption of ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)*. See "Item 7. Management's Discussion and Analysis of Financial Condition of Results of Operations" for a discussion of the impact of adoption of the revenue standard on our financial statements and results of operations.
(2) Total assets and long-term debt include the impact of the adoption of ASU 2016-02, Leases (Topic 842). See Note 12 – Leases.
(3) Distributions declared per unit are no longer relevant after the TRC/TRP Merger.

Item 7. 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 our consolidated financial statements and the notes included in Part IV of this Annual Report. Additional sections in this Annual Report should be helpful to the reading of our discussion and analysis and include the following: (i) a description of our business strategy found in "Item 1. Business–Overview"; (ii) a description of recent developments, found in "Item 1. Business–Recent Developments"; and (iii) a description of risk factors affecting us and our business, found in "Item 1A. Risk Factors."

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)*. The amendments in this update supersede the revenue recognition requirements in Topic 605, Revenue Recognition, and most industry-specific guidance. We adopted Topic 606 on January 1, 2018 by applying the modified retrospective transition approach to contracts which were not completed as of the date of adoption. The adoption of Topic 606 did not result in an impact to our operating or gross margin. However, the adoption did have an impact on the classification between components of operating margin and gross margin, "Fees from midstream services" and "Product purchases," as well as the reporting of gross versus net revenues.

Overview

Targa Resources Partners LP is a Delaware limited partnership formed in October 2006 by TRC. Our common units were listed on the NYSE under the symbol "NGLS" prior to TRC's acquisition on February 17, 2016 of all our outstanding common units that it and its subsidiaries did not already own. Our 9.00% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Preferred Units") remain outstanding as preferred limited partner interests in us and continue to trade on the NYSE under the symbol "NGLS/PA."

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.

Factors That Significantly Affect Our Results

Our results of operations are impacted by a number of factors, including the volumes that move through our gathering, processing and logistics assets, contract terms, changes in commodity prices, the impact of hedging activities and the cost to operate and support assets.

Commodity Prices

The following table presents selected average annual and quarterly industry index prices for natural gas, selected NGL products and crude oil for the periods presented:

	Natural Gas $/MMBtu (1)		Illustrative Targa NGL $/gal (2)		Crude Oil $/Bbl (3)	
2019						
4th Quarter	$	2.50	$	0.49	$	56.96
3rd Quarter		2.23		0.42		56.45
2nd Quarter		2.64		0.50		59.83
1st Quarter		3.16		0.60		54.90
2019 Average		2.63		0.51		57.03
2018						
4th Quarter	$	3.66	$	0.69	$	58.83
3rd Quarter		2.91		0.88		69.50
2nd Quarter		2.80		0.75		67.90
1st Quarter		2.99		0.71		62.89
2018 Average		3.09		0.76		64.78
2017						
4th Quarter	$	2.93	$	0.74	$	55.39
3rd Quarter		2.99		0.63		48.19
2nd Quarter		3.19		0.55		48.29
1st Quarter		3.31		0.61		51.86
2017 Average		3.11		0.63		50.93

(1) Natural gas prices are based on average first of month prices from Henry Hub Inside FERC commercial index prices.
(2) "Illustrative Targa NGL" pricing is weighted using average quarterly prices from Mont Belvieu Non-TET monthly commercial index and represents the following composition for the periods noted:
2019: 38% ethane, 34% propane, 12% normal butane, 5% isobutane and 11% natural gasoline
2018: 38% ethane, 34% propane, 12% normal butane, 5% isobutane and 11% natural gasoline
2017: 38% ethane, 34% propane, 13% normal butane, 5% isobutane and 10% natural gasoline
(3) Crude oil prices are based on average quarterly prices of West Texas Intermediate crude oil as measured on the NYMEX.

Volumes

In our gathering and processing operations, plant inlet volumes, crude oil volumes and capacity utilization rates generally are driven by wellhead production and our competitive and contractual position on a regional basis and more broadly by the impact of prices for crude oil, natural gas and NGLs on exploration and production activity in the areas of our operations. The factors that impact the gathering and processing volumes also impact the total volumes that flow to our Downstream Business. In addition, fractionation volumes are also affected by the location of the resulting mixed NGLs, available pipeline capacity to transport NGLs to our fractionators and our competitive and contractual position relative to other fractionators.

Contract Terms, Contract Mix and the Impact of Commodity Prices

With the potential for volatility of commodity prices, the contract mix of our Gathering and Processing segment (other than fee-based contracts in certain gathering and processing business units and gathering and processing services), can have a significant impact on our profitability, especially those percent-of-proceeds contracts that create direct exposure to changes in energy prices by paying us for gathering and processing services with a portion of proceeds from the commodities handled ("equity volumes").

Contract terms in the Gathering and Processing segment are based upon a variety of factors, including natural gas and crude quality, geographic location, competitive dynamics and the pricing environment at the time the contract is executed, and customer requirements. Our gathering and processing contract mix and, accordingly, our exposure to crude, natural gas and NGL prices may change as a result of producer preferences, competition and changes in production as wells decline at different rates or are added, our expansion into regions where different types of contracts are more common and other market factors.

The contract terms and contract mix of our Downstream Business can also have a significant impact on our results of operations. Transportation and fractionation services are supported by fee-based contracts whose rates and terms are driven by NGL supply and transportation and fractionation capacity. Export services are supported by fee-based contracts whose rates and terms are driven by global LPG supply and demand fundamentals. The Logistics and Transportation segment includes primarily fee-based contracts.

Impact of Our Commodity Price Hedging Activities

We have hedged the commodity price risk associated with a portion of our expected natural gas, NGL and condensate equity volumes, future commodity purchases and sales, and transportation basis risk by entering into financially settled derivative transactions. These transactions include swaps, futures, and purchased puts (or floors) and calls (or caps) to hedge additional expected equity commodity volumes without creating volumetric risk. We intend to continue managing our exposure to commodity prices in the future by entering into derivative transactions. We actively manage the Downstream Business product inventory and other working capital levels to reduce exposure to changing prices. For additional information regarding our hedging activities, see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk–Commodity Price Risk."

Operating Expenses

Variable costs such as fuel, utilities, power, service and repairs can impact our results. The fuel and power costs are pass-through elements in many of our logistics contracts, which mitigates their impact on our results. Continued expansion of existing assets will also give rise to additional operating expenses, which will affect our results. The employees supporting our operations are employees of Targa Resources LLC, a Delaware limited liability company, and an indirect wholly-owned subsidiary of Targa. We reimburse Targa for the payment of certain operating expenses, including compensation and benefits of operating personnel assigned to our assets.

General and Administrative Expenses

Our partnership agreement with Targa, our general partner, addresses the reimbursement of costs incurred on our behalf and indemnification matters. Targa performs centralized corporate functions for us, such as legal, accounting, treasury, insurance, risk management, health, safety, environmental, information technology, human resources, credit, payroll, internal audit, taxes, engineering and marketing. Other than Targa's direct costs of being a separate public reporting company, we reimburse these costs. See "Item 13. Certain Relationships and Related Transactions, and Director Independence."

General Trends and Outlook

We expect the midstream energy business environment to continue to be affected by the following key trends: demand for our products and services, commodity prices, volatile capital markets, competition and increased regulation. These expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about or interpretations of available information prove to be incorrect, our actual results may vary materially from our expected results.

Demand for Our Services

Fluctuations in energy prices can greatly affect production rates and investments by third parties in the development and production of new oil and natural gas reserves. Our operations are affected by the level of crude, natural gas and NGL prices, the relationship among these prices and related activity levels from our customers. Drilling and production activity generally decreases as crude oil and natural gas prices decrease below commercially acceptable levels. Producers generally focus their drilling activity on certain basins depending on commodity price fundamentals. As a result, our asset systems are predominately located in some of the most economic basins in the United States. Accordingly, increased producer activity will drive demand for our midstream services and may result in incremental growth capital expenditures. Demand for our transportation, fractionation and other fee-based services is largely correlated with producer activity levels. Demand for our international export, storage and terminaling services has remained relatively constant during recent commodity price volatility, as demand for these services is based on a number of domestic and international factors.

Commodity Prices

There has been, and we believe there will continue to be, volatility in commodity prices and in the relationships among NGL, crude oil and natural gas prices. In addition, the volatility and uncertainty of natural gas, crude oil and NGL prices impact drilling, completion and other investment decisions by producers and ultimately supply to our systems. Global oil and natural gas commodity prices, particularly crude oil, have declined substantially as compared to mid-2014 and remain volatile. See “Item 1A. Risk Factors – Our cash flow is affected by supply and demand for natural gas and NGL products and by natural gas, NGL, crude oil and condensate prices, and decreases in these prices could adversely affect our results of operations and financial condition.”

Our operating income generally improves in an environment of higher natural gas, NGL and condensate prices, and where the spread between NGL prices and natural gas prices widens primarily as a result of our percent-of-proceeds contracts. Our processing profitability is largely dependent upon pricing and the supply of and market demand for natural gas, NGLs and condensate. Pricing and supply are beyond our control and have been volatile. In a declining commodity price environment, without taking into account our hedges, we will realize a reduction in cash flows under our percent-of-proceeds contracts proportionate to average price declines. Due to the volatility in commodity prices, we are uncertain of what pricing and market demand for oil, condensate, NGLs and natural gas will be throughout 2020, and as a result demand for the services that we provide may decrease. Across our operations, and particularly in our Downstream Business, we benefit from long-term fee-based arrangements for our services, regardless of the actual volumes processed or delivered. The significant level of margin we derive from fee-based arrangements combined with our hedging arrangements helps to mitigate our exposure to commodity price movements. For additional information regarding our hedging activities, see “Item 7A. Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk.”

Volatile Capital Markets and Competition

We continuously consider and enter into discussions regarding potential acquisitions and growth projects and identify appropriate private and public capital sources for funding potential acquisitions and growth projects. Any limitations on our access to capital may impair our ability to execute this strategy. If the cost of such capital becomes too expensive, our ability to develop or acquire strategic and accretive assets may be limited. We may not be able to raise the necessary funds on satisfactory terms, if at all. The primary factors influencing our cost of borrowing include interest rates, credit spreads, covenants, underwriting or loan origination fees and similar charges we pay to lenders. These factors may impair our ability to execute our acquisition and growth strategy.

In addition, we are experiencing increased competition for the types of assets we contemplate purchasing or developing. Current economic conditions and competition for asset purchases and development opportunities could limit our ability to fully execute our growth strategy.

Increased Regulation

Additional regulation in various areas has the potential to materially impact our operations and financial condition. For example, increased regulation of hydraulic fracturing used by producers and increased GHG emission regulations may cause reductions in supplies of natural gas, NGLs and crude oil from producers. Please read "Laws and regulations regarding hydraulic fracturing could result in restrictions, delays or cancellations in drilling and completing new oil and natural gas wells by our customers, which could adversely impact our revenues by decreasing the volumes of natural gas, NGLs or crude oil through our facilities and reducing the utilization of our assets" and "The adoption and implementation of climate change legislation or regulations restricting emissions of GHGs could result in increased operating costs and reduced demand for the products and services we provide" under Item 1A of this Annual Report. Similarly, the forthcoming rules and regulations of the CFTC may limit our ability or increase the cost to use derivatives, which could create more volatility and less predictability in our results of operations.

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 and gathering and processing assets underpinned by fee-based margin, expansion of our downstream facilities, continued focus on adding fee-based margin to our existing and future gathering and processing contracts, 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 gathering and processing, transportation, 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, and Adjusted EBITDA.

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 and our NGL pipelines. 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, other natural gas and crude oil purchases, and our equity volumes hedge settlements; and
- service fees related to natural gas and crude oil gathering, treating and processing.

Logistics and Transportation 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, third-party transportation costs and the net inventory change.

The gross margin impacts of mark-to-market hedge unrealized changes in fair value 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 TRP. 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 TRP 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 make distributions to holders of our equity interests.

Adjusted EBITDA is a non-GAAP financial measure. The GAAP measure most directly comparable to Adjusted EBITDA is net income (loss) attributable to TRP. 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.

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.

	2019	2018	2017
		(In millions)	
Reconciliation of Net Income (Loss) to Operating Margin and Gross Margin			
Net income (loss)	$ (15.6)	$ 98.6	$ (250.6)
Depreciation and amortization expense	971.7	815.9	809.5
General and administrative expense	267.5	240.8	190.5
Impairment of property, plant and equipment	243.2	—	378.0
Impairment of goodwill	—	210.0	—
Interest (income) expense, net	320.8	170.0	217.8
Equity (earnings) loss	(39.0)	(7.3)	17.0
Income tax expense (benefit)	(0.9)	(0.1)	(7.4)
(Gain) loss on sale or disposition of business and assets	71.1	(0.1)	15.9
(Gain) loss from sale of equity-method investment	(69.3)	—	—
(Gain) loss from financing activities	1.4	1.3	10.9
Change in contingent considerations	8.7	(8.8)	(99.6)
Other, net	0.2	3.5	4.0
Operating margin	**1,759.8**	**1,523.8**	**1,286.0**
Operating expenses	792.8	722.0	622.8
Gross margin	**$ 2,552.6**	**$ 2,245.8**	**$ 1,908.8**

	2019	2018	2017
		(In millions)	
Reconciliation of Net Income (Loss) attributable to TRP to Adjusted EBITDA			
Net income (loss) attributable to TRP	$ (254.7)	$ 51.0	$ (289.5)
Interest (income) expense, net (1)	320.8	170.0	217.8
Income tax expense (benefit)	(0.9)	(0.1)	(7.4)
Depreciation and amortization expense	971.7	815.9	809.5
Impairment of property, plant and equipment	243.2	—	378.0
Impairment of goodwill	—	210.0	—
(Gain) loss on sale or disposition of business and assets	71.1	(0.1)	15.9
(Gain) loss from sale of equity-method investment	(69.3)	—	—
(Gain) loss from financing activities (2)	1.4	1.3	10.9
Equity (earnings) loss	(39.0)	(7.3)	17.0
Distributions from unconsolidated affiliates and preferred partner interests, net	61.2	31.5	18.0
Change in contingent considerations	8.7	(8.8)	(99.6)
Transaction costs related to business acquisitions	—	—	5.6
Risk management activities	112.8	8.5	10.0
Noncontrolling interests adjustments (3)	(38.5)	(21.1)	(18.6)
TRP Adjusted EBITDA (4)	**$ 1,388.5**	**$ 1,250.8**	**$ 1,067.6**

(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) Noncontrolling interest portion of depreciation and amortization expense.
(4) Beginning in the second quarter of 2019, we revised our reconciliation of Net Income (Loss) attributable to TRP to Adjusted EBITDA to exclude the Splitter Agreement adjustment previously included in the comparative periods presented herein. For all comparative periods presented, our Adjusted EBITDA measure previously included the Splitter Agreement adjustment, which represented the recognition of the annual cash payment received under the condensate splitter agreement ratably over four quarters. The effect of these revisions reduced TRP's Adjusted EBITDA by $75.2 million and $43.0 million for 2018 and 2017.

Consolidated Results of Operations

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

	Year Ended December 31, 2019	2018	2017	2019 vs. 2018		2018 vs. 2017	
			(In millions)				
Revenues:							
Sales of commodities	$ 7,393.8	$ 9,278.7	$ 7,751.1	$ (1,884.9)	(20%)	$ 1,527.6	20%
Fees from midstream services	1,277.3	1,205.3	1,063.8	72.0	6%	141.5	13%
Total revenues	8,671.1	10,484.0	8,814.9	(1,812.9)	(17%)	1,669.1	19%
Product purchases	6,118.5	8,238.2	6,906.1	(2,119.7)	(26%)	1,332.1	19%
Gross margin (1)	2,552.6	2,245.8	1,908.8	306.8	14%	337.0	18%
Operating expenses	792.8	722.0	622.8	70.8	10%	99.2	16%
Operating margin (1)	1,759.8	1,523.8	1,286.0	236.0	15%	237.8	18%
Depreciation and amortization expense	971.7	815.9	809.5	155.8	19%	6.4	1%
General and administrative expense	267.5	240.8	190.5	26.7	11%	50.3	26%
Impairment of property, plant and equipment	243.2	—	378.0	243.2	—	(378.0)	(100%)
Impairment of goodwill	—	210.0	—	(210.0)	(100%)	210.0	—
Other operating (income) expense	71.3	3.5	17.4	67.8	NM	(13.9)	(80%)
Income (loss) from operations	206.1	253.6	(109.4)	(47.5)	(19%)	363.0	NM
Interest expense, net	(320.8)	(170.0)	(217.8)	(150.8)	(89%)	47.8	22%
Equity earnings (loss)	39.0	7.3	(17.0)	31.7	NM	24.3	143%
Gain (loss) from financing activities	(1.4)	(1.3)	(10.9)	(0.1)	(8%)	9.6	88%
Gain (loss) from sale of equity-method investment	69.3	—	—	69.3	—	—	—
Change in contingent considerations	(8.7)	8.8	99.6	(17.5)	(199%)	(90.8)	(91%)
Other income (expense), net	—	0.1	(2.5)	(0.1)	(100%)	2.6	104%
Income tax (expense) benefit	0.9	0.1	7.4	0.8	NM	(7.3)	(99%)
Net income (loss)	(15.6)	98.6	(250.6)	(114.2)	(116%)	349.2	139%
Less: Net income (loss) attributable to noncontrolling interests	239.1	47.6	38.9	191.5	NM	8.7	22%
Net income (loss) attributable to Targa Resources Partners LP	$ (254.7)	$ 51.0	$ (289.5)	$ (305.7)	NM	$ 340.5	118%
Financial data:							
Adjusted EBITDA (1)	$ 1,388.5	$ 1,250.8	$ 1,067.6	$ 137.7	11%	$ 183.2	17%
Growth capital expenditures (2)	2,566.8	3,192.7	1,405.7	(625.9)	(20%)	1,787.0	127%
Maintenance capital expenditures (3)	141.7	135.0	100.8	6.7	5%	34.2	34%
Business acquisition (4)	—	—	987.1	—	—	(987.1)	(100%)

(1) Gross margin, operating margin, and Adjusted EBITDA 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 interests, were $2,201.7 million, $2,612.8 million and $1,342.4 million for the years ended December 31, 2019, 2018 and 2017. Net contributions to investments in unconsolidated affiliates were $80.0 million, $113.4 million and $9.5 million for the years ended December 31, 2019, 2018 and 2017.
(3) Maintenance capital expenditures, net of contributions from noncontrolling interests, were $134.9 million, $127.9 million and $99.1 million for the years ended December 31, 2019, 2018 and 2017.
(4) Includes the $416.3 million acquisition date fair value of the potential earn-out payments. The final earn-out payment of $317.1 million was made in May 2019.
NM Due to a low denominator, the noted percentage change is disproportionately high and as a result, considered not meaningful.

2019 Compared to 2018

The decrease in commodity sales reflects lower NGL and natural gas prices ($3,296.9 million) and lower petroleum products volumes due to the sale of certain Petroleum Logistics terminals in the fourth quarter of 2018 ($63.8 million), partially offset by higher NGL, crude marketing, natural gas, and condensate volumes ($1,433.4 million) and the favorable impact of hedges ($68.0 million). Fees from midstream services increased primarily due to higher export and crude gathering fees.

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

Higher operating margin and gross margin in 2019 reflect increased segment results for both Gathering and Processing and Logistics and Transportation. 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 additional processing plants and associated infrastructure in the Permian Basin and Grand Prix.

General and administrative expense increased primarily due to higher compensation and benefits costs and higher information technology costs resulting from increased staffing levels, and higher insurance costs.

Our impairment of property, plant and equipment in 2019 included a partial impairment of gas processing facilities and gathering systems associated with the North Texas and Coastal operations in our Gathering and Processing segment, and an asset write-down associated with certain treating units within the same segment. The impairment resulted from the continuing decline in natural gas production across the Barnett Shale in North Texas and Gulf of Mexico due to the sustained low commodity price environment. We did not recognize any impairments of property, plant and equipment in 2018.

We did not record any goodwill impairment charges for the year ended December 31, 2019, as the fair values of all reporting units exceeded their accounting carrying values. We recognized impairments of goodwill totaling $210.0 million during 2018 related to the remaining goodwill associated with the acquisition of Atlas Energy L.P. and Atlas Pipeline Partners L.P. in 2015 (collectively the "Atlas mergers").

Other operating (income) expense in 2019 consisted primarily of a loss associated with the sale of our crude gathering and storage business in Permian Delaware. The 2018 expense consisted primarily of the loss on sale of certain Petroleum Logistics terminals and the loss on disposal of the benzene saturation component of our LSNG hydrotreater, partially offset by the gain on sale of our inland marine barge business and the gain on an exchange of a portion of our Versado gathering system.

Higher interest expense, net, in 2019 was primarily due to 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.

Equity earnings increased in 2019 primarily due to earnings from GCX and Little Missouri 4, resulting from the commencement of operations of GCX Pipeline and LM4 Plant in the third quarter.

During 2019, we closed on the sale of an equity-method investment that resulted in a gain of $69.3 million.

In 2019, we recorded expense of $8.7 million resulting from an increase in the value of the Permian Acquisition contingent consideration liability. The increase was primarily attributable to the elimination of discounting and an increase in actual gross margin through the end of the earn-out period. The earn-out period ended and resulted in a final payment in May 2019. During 2018 we recorded income of $8.8 million resulting from the decrease in fair value of the contingent consideration. The decrease was primarily attributable to lower forecasted volumes for the remainder of the earn-out period, partially offset by a shorter discount period.

Net income attributable to noncontrolling interests was higher in 2019 due to the sale of ownership interests in Targa Badlands and increased earnings allocated to interests holders in Grand Prix, GCX, and Train 6.

2018 Compared to 2017

The increase in commodity sales reflects increased NGL, natural gas, petroleum and condensate volumes ($1,606.0 million) and higher NGL and condensate prices ($742.2 million), partially offset by lower natural gas prices ($465.7 million) and the impact of hedges ($22.4 million). Fees from midstream services increased primarily due to higher gas processing and crude gathering fees.

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

The prospective adoption of the revenue recognition accounting standard as set forth in Topic 606 in 2018 resulted in lower commodity sales ($333.2 million) and lower fee revenue ($39.6 million) with a corresponding net reduction in product purchases, resulting in no impact on operating margin or gross margin.

The higher operating margin and gross margin in 2018 reflect increased segment results for both Gathering and Processing and Logistics and Transportation. 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 due to higher depreciation related to our growth investments, partially offset by lower depreciation for our North Texas system, which incurred an impairment write-down in 2017, lower scheduled amortization of Badlands intangibles and lower depreciation on our inland marine barge business sold in the second quarter of 2018.

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

In conjunction with our required annual goodwill assessments, we recognized impairments of goodwill totaling $210.0 million during 2018 related to the remaining goodwill from the Atlas mergers. There was no impairment of goodwill in 2017 as the fair values of affected reporting units exceeded their accounting carrying values.

Other operating (income) expense in 2018 was comprised primarily of the loss on sale of certain Petroleum Logistics terminals, the loss on disposal of the benzene saturation component of our LSNG hydrotreater and the loss for abandoned project development costs, partially offset by the gain on sale of our inland marine barge business and the gain on an exchange of a portion of our Versado gathering system. In 2017, other operating (income) expense included the loss on sale of our 100% ownership interest in the Venice gathering system.

Lower interest expense, net, in 2018 was primarily due to higher non-cash interest income related to a lower valuation of the mandatorily redeemable preferred interests liability and higher capitalized interest related to our major growth investments. These factors more than offset the impact of higher average outstanding borrowings during 2018.

Equity earnings increased in 2018 primarily due to decreased losses of the T2 Joint Ventures, increased earnings resulting from the commencement of operations at Cayenne and increased earnings at Gulf Coast Fractionators. Equity losses of the T2 Joint Ventures in 2017 included a $12.0 million impairment of our investment in the T2 EF Cogen joint venture.

In 2018, we recorded a loss from financing activities of $1.3 million associated with amendments of our revolving credit facility, which resulted in a write-off of debt issuance costs. In 2017, we recorded a loss from financing activities of $10.9 million upon the redemption of outstanding 6⅜% Senior Notes.

The decrease in fair value of the contingent consideration in 2018 was primarily attributable to lower forecasted volumes for the remainder of the earn-out period, partially offset by a shorter discount period. The decrease in fair value of the contingent consideration in 2017 was primarily related to reductions in forecasted volumes and gross margin as a result of changes in producers' drilling activity in the region.

We recorded an income tax benefit in 2017 primarily due to a Texas Margin Tax refund.

Net income attributable to noncontrolling interests was higher in 2018 due to increased earnings at the Carnero Joint Venture, Centrahoma, Cedar Bayou Fractionators and Venice Energy Services Company, L.L.C.

Results of Operations—By Reportable Segment

Our operating margins by reportable segment are:

	Gathering and Processing	Logistics and Transportation	Other	Consolidated Operating Margin
	(In millions)			
2019	$ 1,006.5	$ 867.2	$ (113.9)	$ 1,759.8
2018	939.2	592.5	(7.9)	1,523.8
2017	776.4	511.8	(2.2)	1,286.0

Gathering and Processing Segment

	Year Ended December 31,							
	2019	2018	2017	2019 vs. 2018		2018 vs. 2017	
Gross margin	$ 1,496.1	$ 1,377.5	$ 1,138.1	$ 118.6	9%	$ 239.4	21%
Operating expenses	489.6	438.3	361.7	51.3	12%	76.6	21%
Operating margin	$ 1,006.5	$ 939.2	$ 776.4	$ 67.3	7%	$ 162.8	21%
Operating statistics (1):							
Plant natural gas inlet, MMcf/d (2),(3)							
Permian Midland (4)	1,489.1	1,141.2	893.5	347.9	30%	247.7	28%
Permian Delaware	599.7	443.9	381.8	155.8	35%	62.1	16%
Total Permian	2,088.8	1,585.1	1,275.3	503.7		309.8	
SouthTX (5)	321.2	389.6	273.2	(68.4)	(18%)	116.4	43%
North Texas	226.9	244.1	268.1	(17.2)	(7%)	(24.0)	(9%)
SouthOK (6)	606.1	555.7	494.0	50.4	9%	61.7	12%
WestOK	330.2	351.6	377.7	(21.4)	(6%)	(26.1)	(7%)
Total Central	1,484.4	1,541.0	1,413.0	(56.6)		128.0	
Badlands (7), (8)	116.7	85.1	56.5	31.6	37%	28.6	51%
Total Field	3,689.9	3,211.2	2,744.8	478.7		466.4	
Coastal	748.3	726.2	728.8	22.1	3%	(2.6)	-
Total	4,438.2	3,937.4	3,473.6	500.8	13%	463.8	13%
NGL production, MBbl/d (3)							
Permian Midland (4)	209.1	153.4	118.3	55.7	36%	35.1	30%
Permian Delaware	78.6	53.5	43.1	25.1	47%	10.4	24%
Total Permian	287.7	206.9	161.4	80.8		45.5	
SouthTX (5)	41.6	51.1	30.4	(9.5)	(19%)	20.7	68%
North Texas	26.8	28.1	30.2	(1.3)	(5%)	(2.1)	(7%)
SouthOK (6)	67.1	54.7	42.8	12.4	23%	11.9	28%
WestOK	21.6	20.5	21.9	1.1	5%	(1.4)	(6%)
Total Central	157.1	154.4	125.3	2.7		29.1	
Badlands (8)	13.8	10.8	7.9	3.0	28%	2.9	37%
Total Field	458.6	372.1	294.6	86.5		77.5	
Coastal	46.8	43.6	38.6	3.2	7%	5.0	13%
Total	505.4	415.7	333.2	89.7	22%	82.5	25%
Crude oil gathered, Badlands, MBbl/d	172.6	146.8	113.6	25.8	18%	33.2	29%
Crude oil gathered, Permian, MBbl/d (9)	83.3	64.9	29.8	18.4	28%	35.1	118%
Natural gas sales, BBtu/d (3)	2,020.6	1,867.9	1,665.4	152.7	8%	202.5	12%
NGL sales, MBbl/d (3)	391.9	317.6	254.8	74.3	23%	62.8	25%
Condensate sales, MBbl/d	14.7	12.6	11.8	2.1	17%	0.8	7%
Average realized prices - inclusive of hedges (10):							
Natural gas, $/MMBtu	1.35	2.05	2.67	(0.70)	(33%)	(0.62)	(23%)
NGL, $/gal	0.34	0.62	0.54	(0.28)	(50%)	0.08	15%
Condensate, $/Bbl	51.46	51.04	46.77	0.42	1%	4.28	9%

(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 year and the denominator is the number of calendar days during the year.
(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, and includes the Targa-gathered volumes processed at the LM4 Plant.
(8) As of April 3, 2019, Targa owns 55% of Targa Badlands, prior to which we owned a 100% interest. Targa Badlands is a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials.

(9) Permian crude oil gathered volumes reflect the sale of the Delaware crude gathering system, which was effective December 1, 2019.
(10) Average realized prices include the effect of realized commodity hedge gain/loss attributable to our equity volumes, previously shown in Other. The price is calculated using total commodity sales plus the hedge gain/loss as the numerator and total sales volume as the denominator.

The following table presents the realized commodity hedge gain/loss attributable to our equity volumes that are included in the gross margin of Gathering and Processing segment:

	Year Ended December 31, 2019			Year Ended December 31, 2018			Year Ended December 31, 2017		
	(In millions, except volumetric data and price amounts)								
	Volume Settled	Price Spread (1)	Gain (Loss)	Volume Settled	Price Spread (1)	Gain (Loss)	Volume Settled	Price Spread (1)	Gain (Loss)
Natural gas (BBtu)	62.9	$ 1.17	$ 73.7	63.5	$ 0.82	$ 51.9	61.1	$ 0.22	$ 13.5
NGL (MMgal)	369.7	0.10	38.0	367.4	(0.16)	(58.4)	262.9	(0.10)	(26.0)
Crude oil (MBbl)	1.5	(2.29)	(3.5)	2.0	(11.25)	(22.7)	1.3	4.09	5.1
			$ 108.2			$ (29.2)			$ (7.4)

(1) The price spread is the differential between the contracted derivative instrument pricing and the price of the corresponding settled commodity transaction.

2019 Compared to 2018

The increase in gross margin was primarily due to higher volumes in the Permian and Badlands, partially offset by lower Central volumes and realized prices. NGL production and NGL sales increased primarily due to higher inlet volumes and increased NGL recoveries. Natural gas sales increased primarily due to higher inlet volumes. In the Permian, natural gas inlet volumes and NGL production increased due to production from new wells and the addition of the Hopson, Pembrook and Falcon plants in 2019. In the Badlands, natural gas gathered volumes and NGL production increased due to production from new wells and the incremental processing capacity available with the commencement of operations at the LM4 Plant in the third quarter of 2019. Total crude oil gathered volumes increased in both the Permian and the Badlands due to production from new wells.

The increase in operating expenses was primarily driven by gas plant and system expansions in the Permian region.

2018 Compared to 2017

The increase in gross margin was primarily due to higher Permian, Badlands and Central volumes and higher NGL and condensate realized prices, partially offset by the impact of lower realized natural gas prices. NGL production, NGL sales and natural gas sales increased due to higher Field Gathering and Processing inlet volumes and increased NGL recoveries including reduced ethane rejection. Coastal Gathering and Processing had a positive margin impact due to richer gas, increased recoveries and higher realized NGL prices, partially offset by slightly lower inlet volumes. Total crude oil gathered volumes increased in the Permian region due to production from new wells, system expansions and the inclusion of the March 2017 Permian Acquisition for the full year in 2018. In the Badlands, total crude oil gathered volumes and natural gas gathered volumes increased primarily due to production from new wells and system expansions.

Operating expenses increased as a result of higher compensation, contract labor and other costs primarily associated with new plants in the Permian and Central regions and system expansions in the Badlands.

Equity volume hedges

The Gathering and Processing segment contains the results of commodity derivative activities related to hedges of equity volumes that are included in gross margin. 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. See further details of our risk management program in “Item 7A. – Quantitative and Qualitative Disclosures About Market Risk.”

Logistics and Transportation Segment

	Year Ended December 31,									
	2019		2018		2017		2019 vs. 2018		2018 vs. 2017	
	(In millions, except operating statistics and price amounts)									
Gross margin	$	1,173.9	$	876.8	$	773.4	$ 297.1	34%	$ 103.4	13%
Operating expenses		306.7		284.3		261.6	22.4	8%	22.7	9%
Operating margin	$	867.2	$	592.5	$	511.8	$ 274.7	46%	$ 80.7	16%
Operating statistics MBbl/d (1):										
Fractionation volumes (2)		519.0		426.7		354.2	92.3	22%	72.5	20%
Export volumes (3)		237.9		203.4		184.1	34.5	17%	19.3	10%
Pipeline throughput (4)		100.4		-		-	100.4	-	-	-
NGL sales		651.0		537.9		490.0	113.1	21%	47.9	10%
Average realized prices:										
NGL realized price, $/gal	$	0.51	$	0.77	$	0.69	$ (0.26)	(38%)	$ 0.08	12%

(1) Segment operating statistics include intersegment amounts, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume sold during the year and the denominator is the number of calendar days during the year.
(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 Transportation 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 and 2017 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.
(4) Pipeline throughput represents the total quantity of mixed NGLs delivered by Grand Prix, which commenced full operations in the third quarter of 2019, to Mont Belvieu.

2019 Compared to 2018

The increase in Logistics and Transportation gross margin was primarily due to higher NGL transportation and fractionation volumes and higher LPG export volumes. Segment gross margin increased due to higher NGL transportation and fractionation margin, higher marketing margin, and higher LPG export margin, partially offset by the sale of certain Petroleum Logistics terminals in the fourth quarter of 2018. NGL transportation and fractionation margin increased due to volumes delivered on Grand Prix, which began full service into Mont Belvieu during the third quarter of 2019, and higher fractionation volumes as a result of the commencement of operations of Train 6 in the second quarter of 2019, partially offset by fewer short-term high-fee fractionation contracts in 2019 and less favorable system product gains. Marketing margin increased due to optimization of liquids and gas arrangements. LPG export margin increased primarily due to higher volumes.

Operating expenses increased due to higher compensation and benefits and higher taxes primarily attributable to Grand Prix and Train 6 operations that commenced in 2019, higher maintenance, and higher fuel and power costs that are largely passed through to customers.

2018 Compared to 2017

Logistics and Transportation gross margin increased due to higher fractionation margin, higher domestic marketing margin, higher LPG export margin, and higher terminaling and storage throughput, partially offset by lower commercial transportation margin and lower marketing gains. Fractionation margin increased due to higher supply volume and higher fees, partially offset by lower system product gains. Fractionation margin was partially impacted by the variable effects of fuel and power which are largely reflected in operating expenses (see footnote (2) above). Domestic marketing margin increased due to higher terminal volumes and higher unit margins. LPG export margin increased primarily due to higher volumes. Commercial transportation margin decreased primarily due to the sale of the Company’s inland marine barge business in the second quarter of 2018.

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

Other

	Year Ended December 31,				
	2019	2018	2017	2019 vs. 2018	2018 vs. 2017
	(In millions)				
Gross margin	$ (113.9)	$ (7.9)	$ (2.2)	$ (106.0)	$ (5.7)
Operating margin	$ (113.9)	$ (7.9)	$ (2.2)	$ (106.0)	$ (5.7)

Other contains the results of commodity derivative activity mark-to-market gains/losses related to derivative contracts that were not designated as cash flow hedges. We have entered into derivative instruments to hedge the commodity price associated with a portion of our future commodity purchases and sales and natural gas transportation basis risk within our Logistics and Transportation segment. See further details of our risk management program in "Item 7A. – Quantitative and Qualitative Disclosures About Market Risk."

Liquidity and Capital Resources

As of December 31, 2019, we had $291.1 million of "Cash and cash equivalents" on our Consolidated Balance Sheet. We believe our cash flows from operating activities, cash position, and remaining borrowing capacity on our credit facilities (discussed below in "Short-term Liquidity") are adequate to allow us to manage our day-to-day cash requirements and anticipated obligations as discussed further below.

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

Our main sources of liquidity and capital resources are internally generated cash flows from operations, contributions from TRC that are funded through TRC's access to debt and equity markets, borrowings under the TRP Revolver and the Securitization Facility, access to debt markets and joint venture arrangements. We may supplement these sources of liquidity with 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 facility, cash investments, hedging abilities, customer performance risks and counterparty performance risks.

Short-term Liquidity

Our short-term liquidity as of February 14, 2020, was:

		February 14, 2020 (In millions)
Cash on hand		$ 335.7
Total availability under the TRP Revolver		2,200.0
Total availability under the Securitization Facility		400.0
		2,935.7
Less:	Outstanding borrowings under the TRP Revolver	(230.0)
	Outstanding borrowings under the Securitization Facility	(400.0)
	Outstanding letters of credit under the TRP Revolver	(87.9)
	Total liquidity	$ 2,217.8

Other potential capital resources associated with our existing arrangements include:

- 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 December 31, 2019 increased $1,138.7 million compared to December 31, 2018. The increase was primarily attributable to the redemption of our 4⅛% Senior Notes due 2019 and the contingent consideration payment associated with the Permian Acquisition, with funding provided by the issuance of long-term senior notes. The reclassification of long-term Delaware crude gathering and storage assets to current held for sale assets, and cash received from the sale of an equity-method investment also contributed to the increase in working capital.

Based on our anticipated levels of operations and absent any disruptive events, we believe that internally generated cash flow, contributions from TRC, borrowings available under the TRP Revolver and the Securitization Facility and proceeds from debt offerings, as well as joint ventures and/or potential asset sales, should provide sufficient resources to finance our operations, capital expenditures, long-term debt obligations, collateral requirements and cash distributions to Targa for at least the next twelve months.

Long-term Financing

Our long-term financing consists of potentially raising funds through the issuance of preferred units, long-term debt obligations or joint venture arrangements.

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 December 31, 2019, total contributions from Stonepeak to the DevCo JVs were $898.6 million. As of December 31, 2019, total contributions from Blackstone to the Grand Prix Joint Venture were $329.6 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 December 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 $7,005.2 million and $5,632.4 million, respectively.

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 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 December 31, 2019, we did not have any interest rate hedges.

In January 2019, we 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 $1,486.6 million. The net proceeds from the issuance were used to redeem in full our outstanding 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 repayment of borrowings under its credit facilities or other indebtedness. To date, our 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 10 - Debt Obligations to our consolidated financial statements. For information about our interest rate risk, see "Item 3. Quantitative and Qualitative Disclosures About Market Risk—Interest Rate Risk."

In April 2019, we closed on the sale of a 45% interest in Targa Badlands, the entity that holds substantially all of the assets previously wholly owned by Targa 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 and hold majority governance rights. Future growth capital of Targa Badlands is expected to be funded on a pro rata ownership basis. Targa Badlands pays 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. Targa Badlands is a discrete entity and the assets and credit of Targa Badlands are not available to satisfy the debts and other obligations of Targa or its other subsidiaries. As of December 31, 2019, the contributions from Blackstone were $71.3 million.

In the second quarter of 2019, Williams exercised its initial option to acquire a 20% equity interest in Train 7 and subsequently 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. As of December 31, 2019, the contributions from Williams were $23.7 million.

In November 2019, we issued $1.0 billion aggregate principal amount of 5½% Senior Notes due March 2030, resulting in net proceeds of $990.8 million. The net proceeds from the issuance were used to repay borrowings under its credit facilities and for general partnership purposes.

Distributions on our 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 our general partner. Distributions on our 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 our Preferred Units will accumulate at an annual floating rate equal to the one-month LIBOR plus a spread of 7.71%. At any time on or after November 1, 2020, we may redeem the Preferred Units, in whole or in part, from any source of funds legally available for such purpose, by paying $25.00 per unit plus an amount equal to all accumulated and unpaid distributions thereon to the date of redemption, whether or not declared. In addition, we (or a third party with our prior written consent) may redeem the Preferred Units following certain changes of control, as described in our Partnership Agreement. If we do not (or a third party with our prior written consent does not) exercise this option, then the Preferred Unitholders have the option to convert the Preferred Units into a number of common units per Preferred Unit as set forth in our Partnership Agreement.

Compliance with Debt Covenants

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

Cash Flow

Cash Flows from Operating Activities

2019	2018	2017	2019 vs. 2018	2018 vs. 2017
		(In millions)		
$ 1,363.0	$ 1,213.6	$ 857.6	$ 149.4	$ 356.0

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 increased in 2019 compared to 2018 primarily due to the net favorable impact of higher volumes and lower commodity prices, and an increase in cash received from hedging activities resulting from changes in commodity prices, partially offset by an increase in interest payments as a result of higher average borrowings.

Net cash provided by operations increased from 2017 to 2018 primarily due to the impact of higher NGL and condensate prices and volumes, decreased margin calls from futures contracts, partially offset by increases in payments for operating expenses. The rising commodity prices and volumes resulted in higher cash collections from customers, partially offset by higher product purchases. Increases in payments for operating expenses were mainly due to system expansions.

Cash Flows from Investing Activities

2019	2018	2017	2019 vs. 2018	2018 vs. 2017
	(In millions)			
$ (3,071.4)	$ (3,146.1)	$ (1,892.7)	$ 74.7	$ (1,253.4)

Cash used in investing activities decreased slightly in 2019 compared to 2018, primarily due to lower cash outlays for property, plant and equipment, partially offset by lower proceeds from fewer assets and business sales. Our capital expenditures for property, plant and equipment decreased $236.7 million primarily due to lower spending on Grand Prix as it began operations in the third quarter. In 2019, we received proceeds of $85.1 million from asset sales, primarily from the sale of an equity-method investment. In 2018, we received proceeds of $256.9 million from the sale of certain Petroleum Logistics terminals, the sale of our inland marine barge business and the exchange of a portion of our Versado gathering system.

Cash used in investing activities increased in 2018 compared to 2017, primarily due to increased outlays for property, plant and equipment and contributions to unconsolidated affiliates, partially offset by lower outlays for business acquisitions and higher proceeds from the sale of assets. Our capital expenditures for property, plant and equipment increased $1,816.5 million in 2018 primarily related to a large number of capital projects, and our contributions to unconsolidated affiliates increased $272.5 million primarily due to the construction activities of GCX Pipeline and the LM4 Plant. We have made no cash payment for business acquisitions in 2018, whereas in 2017 we paid $570.8 million for the initial cash portion of the Permian Acquisition. In 2018, we received proceeds of $256.9 million from the sale of refined products and crude oil storage and terminaling facilities, the sale of our inland marine barge business and the exchange of a portion of our Versado gathering system.

Cash Flows from Financing Activities

	2019	2018	2017
Source of Financing Activities, net		(In millions)	
Sale of ownership interests in subsidiaries	$ 1,619.7	$ —	$ —
Debt, including financing costs	1,104.4	1,593.8	149.4
Contributions from noncontrolling interests, net	363.6	747.1	93.5
Contributions from TRC and General Partner	200.0	600.1	1,720.0
Distributions	(1,163.7)	(929.8)	(858.6)
Payment of contingent consideration	(317.1)	—	—
Other	(10.7)	(0.1)	(12.5)
Net cash provided by financing activities	$ 1,796.2	$ 2,011.1	$ 1,091.8

In 2019, we realized a net source of cash from financing activities primarily due to the sale of ownership interests in Targa Badlands and Train 7, net increase of debt outstanding and net contributions from noncontrolling interests. The result was partially offset by payments of distributions to TRC, as well as the final contingent consideration payment associated with the Permian Acquisition. During 2019, we issued 6½% Senior Notes due 2027, 6⅞% Senior Notes due January 2029 and 5½% Senior Notes due March 2030, with the use of proceeds to repay TRP Revolver and to redeem 4⅛% Senior Notes due November 2019, resulting in net increases in debt outstanding. We received net contributions from noncontrolling interests primarily from Stonepeak and Blackstone to fund growth projects.

In 2018, we realized a net source of cash from financing activities primarily due to a net increase of debt outstanding and contributions from noncontrolling interests and TRC, partially offset by payments of distributions to TRC. The issuance of 5⅞% Senior Notes due 2026 and increases in net borrowings under TRP Revolver contributed to higher net debt outstanding. The contributions from noncontrolling interests were primarily from Stonepeak and Blackstone to fund growth projects.

In 2017, we realized a net source of cash from financing activities primarily due to contributions from TRC and our General Partner, partially offset by a net reduction of debt borrowings and payments of distributions to TRC. We reduced net debt borrowings through repayments of the TRP Revolver and redemption of our 6⅜% Senior Notes. In October 2017, we issued 5% Senior Notes due 2028 and used a portion of the proceeds to redeem our 5% Senior Notes due 2018. During 2017, we sold a 25% interest in the Grand Prix Joint Venture to Blackstone, which contributed a total of $96.3 million to the joint venture in 2017. The contributions from Blackstone are included in financing activities as contributions from noncontrolling interests.

Distributions

The following table details the distributions declared and/or paid by us for 2019:

Three Months Ended	Date Paid	Total Distributions	Distributions to Targa Resources Corp.
December 31, 2019	February 14, 2020	$ 241.9	$ 239.1
September 30, 2019	November 13, 2019	242.1	239.3
June 30, 2019	August 13, 2019	242.4	239.6
March 31, 2019	April 5, 2019	437.8	435.0

Preferred Units

Distributions on our Preferred Units are declared and paid monthly. As of December 31, 2019, we have 5,000,000 Preferred Units outstanding. For the year ended December 31, 2019, $11.3 million of distributions were paid. We have accrued distributions to Series A Preferred Unitholders of $0.9 million for December, which were paid subsequently on January 15, 2020.

In January and February 2020, the board of directors of our general partner declared a cash distribution of $0.9 million cash each month for $0.1875 per Preferred Unit. The distributions declared in January were paid on February 18, 2020 and the distributions declared in February will be paid on March 16, 2020.

Capital Expenditures

Our capital expenditures are classified as growth capital expenditures, business acquisitions, and maintenance expenditures. Growth capital expenditures are typically related to significant expansions of facilities or pipe, or significant pipeline extensions, and other expenditures that improve the service capability of existing assets, extend asset useful lives, increase capacities from existing levels, add capabilities, reduce costs, or enhance revenues. 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 near completion of their useful life and expenditures to remain in compliance with environmental laws and regulations.

	2019	2018	2017
		(In millions)	
Capital expenditures:			
Consideration for business acquisition	$ —	$ —	$ 987.1
Contingent consideration (1)	—	—	(416.3)
Cash outlay for business acquisition, net of cash acquired	—	—	570.8
Growth (2)	2,566.8	3,192.7	1,405.7
Maintenance (3)	141.7	135.0	100.8
Gross capital expenditures	2,708.5	3,327.7	1,506.5
Transfers of capital expenditures to investment in unconsolidated affiliates	—	16.0	—
Transfers from materials and supplies inventory to property, plant and equipment	(25.1)	(12.7)	(3.6)
Change in capital project payables and accruals	193.9	(217.0)	(205.4)
Cash outlays for capital projects	2,877.3	3,114.0	1,297.5
Total capital outlays	$ 2,877.3	$ 3,114.0	$ 1,868.3

(1) See Note 4 – Joint Ventures, Acquisitions and Divestitures of the "Consolidated Financial Statements." Represents the fair value of contingent consideration at the acquisition date. The final earn-out payment of $317.1 million was made in May 2019.
(2) Growth capital expenditures, net of contributions from noncontrolling interests, were $2,201.7 million, $2,612.8 million and $1,342.4 million for the years ended December 31, 2019, 2018 and 2017. Net contributions to investments in unconsolidated affiliates were $80.0 million, $113.4 million and $9.5 million for the years ended December 31, 2019, 2018 and 2017.
(3) Maintenance capital expenditures, net of contributions from noncontrolling interests, were $134.9 million, $127.9 million and $99.1 million for the years ended December 31, 2019, 2018 and 2017.

During 2019, we invested $2,281.7 million in growth capital expenditures, net of noncontrolling interests (exclusive of outlays for business acquisitions), and net contributions to investments in unconsolidated affiliates ("net growth capital expenditures"). We currently estimate that in 2020 we will invest approximately between $1,200 to $1,300 million in net growth capital expenditures for announced projects. Future growth capital expenditures may vary based on investment opportunities. We expect that 2020 maintenance capital expenditures, net of noncontrolling interests, will be approximately $150 million.

Our growth capital expenditures decreased for the year ended December 31, 2019 as compared to the year ended December 31, 2018, primarily due to lower spending on Grand Prix as it began operations in the third quarter, partially offset by spending related to construction of Train 7 and Train 8, and additional processing plants and associated infrastructure in the Permian Basin. Our maintenance capital expenditures were relatively flat for 2019 as compared to 2018.

Our growth capital expenditures increased for the year ended December 31, 2018 as compared to the year ended December 31, 2017, primarily due to spending related to Grand Prix, additional processing plants and associated infrastructure in the Permian Basin, SouthOK and Badlands, and construction of Train 6. Our maintenance capital expenditures increased for 2018 as compared to 2017, primarily due to our increased asset base and additional infrastructure.

Off-Balance Sheet Arrangements

As of December 31, 2019, there were $54.9 million in surety bonds outstanding related to various performance obligations. These are in place to support various performance obligations as required by (i) statutes within the regulatory jurisdictions where we operate and (ii) counterparty support. Obligations under these surety bonds are not normally called, as we typically comply with the underlying performance requirement.

We have invested in entities that are not consolidated in our financial statements. For information on our obligations with respect to these investments, as well as our obligations with respect to related letters of credit, see Note 8 – Investments in Unconsolidated Affiliates and Note 10 – Debt Obligations.

Contractual Obligations

In addition to disclosures related to debt and lease obligations, contained in our "Consolidated Financial Statements" beginning on page F-1 of this Annual Report, the following is a summary of certain contractual obligations over the next several years:

	Payments Due By Period				
Contractual Obligations	**Total**	**Less Than 1 Year**	**1-3 Years**	**3-5 Years**	**More Than 5 Years**
			(in millions)		
Long-term debt obligations (1)	$ 7,028.2	$ —	$ 6.5	$ 1,771.7	$ 5,250.0
Interest on debt obligations (2)	2,775.8	410.4	800.6	692.1	872.7
Finance leases (3)	40.5	13.4	21.9	5.2	-
Operating leases (4)	26.8	7.4	12.5	6.5	0.4
Land site lease and rights of way (5)	150.4	3.8	8.4	8.8	129.4
Purchase Obligations (6):					
Pipeline capacity and throughput agreements (7)	1,197.7	185.7	337.9	236.3	437.8
Commodities (8)	94.9	81.4	13.5	—	—
Purchase commitments and service contracts (9)	366.3	350.6	6.3	2.4	7.0
Other long-term liabilities (10)	39.2	—	6.6	5.2	27.4
	$ 11,719.8	$ 1,052.7	$ 1,214.2	$ 2,728.2	$ 6,724.7
Commodity Volumetric Commitments					
Natural gas (MMBtu)	20.8	20.8	—	—	—
NGLs (MMgal)	290.1	206.1	84.0	—	—

(1) Represents scheduled future maturities of long-term debt obligations for the periods indicated. See Note 10 - Debt Obligations for more information regarding our debt obligations.
(2) Represents interest expense on debt obligations based on both fixed debt interest rates and prevailing December 31, 2019 rates for floating debt. See Note 10 - Debt Obligations for more information regarding our debt obligations.
(3) Includes minimum payments on finance lease obligations for vehicles and tractors. See Note 12 - Leases for more information regarding our finance leases.
(4) Includes minimum payments on operating lease obligations for office space and railcars. See Note 12 – Leases for more information regarding our operating leases.
(5) Land site lease and rights of way provides for surface and underground access for gathering, processing and distribution assets that are located on property not owned by us. These agreements expire at various dates with varying terms, some of which are perpetual. See Note 17 - Commitments for more information regarding our land site lease and rights of way.
(6) A purchase obligation represents an agreement to purchase goods or services that is enforceable, legally binding and specifies all significant terms, including: fixed minimum or variable prices provisions; and the approximate timing of the transaction.
(7) Consists of pipeline capacity payments for firm transportation and throughput and deficiency agreements.
(8) Includes natural gas and NGL purchase commitments. Contracts that will be settled at future spot prices are valued using prices as of December 31, 2019.
(9) Includes commitments for capital expenditures, operating expenses and service contracts.
(10) Includes long-term liabilities of which we are certain of the amount and timing, including certain arrangements that resulted in deferred revenue. See Note 11 - Other Long-term Liabilities for more information regarding our other long-term liabilities.

Critical Accounting Policies and Estimates

The accounting policies and estimates discussed below are considered by management to be critical to an understanding of our financial statements because their application requires the most significant judgments from management in estimating matters for financial reporting that are inherently uncertain. See the description of our accounting policies in the notes to the financial statements for additional information about our critical accounting policies and estimates.

Depreciation of Property, Plant and Equipment and Amortization of Intangible Assets

Depreciation of our property, plant and equipment is computed using the straight-line method over the estimated useful lives of the assets. Our estimate of depreciation incorporates assumptions regarding the useful economic lives and residual values of our assets. The determination of useful lives of property, plant and equipment requires us to make various assumptions, including our expected use of the asset and the supply of and demand for hydrocarbons in the markets served, normal wear and tear of facilities, and the extent and frequency of maintenance programs.

We amortize the costs of our intangible assets in a manner that closely resembles the expected benefit pattern of the intangible assets or on a straight-line basis, where such pattern is not readily determinable, over the periods in which we benefit from services provided to customers. At the time assets are placed in service or acquired, we believe such assumptions are reasonable; however, circumstances may develop that would cause us to change these assumptions, which would change our depreciation/amortization amounts prospectively.

Impairment of Long-Lived Assets, including Intangible Assets

We evaluate long-lived assets for impairment when events or changes in circumstances indicate our carrying amount of an asset may not be recoverable. Asset recoverability is measured by comparing the carrying value of the asset or asset group with its expected future pre-tax undiscounted cash flows. Individual assets are grouped at the lowest level for which the related identifiable cash flows are largely independent of the cash flows of other assets and liabilities. These cash flow estimates require us to make judgments and assumptions related to operating and cash flow results, economic obsolescence, the business climate, contractual, legal and other factors.

If the carrying amount exceeds the expected future undiscounted cash flows, we recognize an impairment equal to the excess of net book value over fair value as determined by quoted market prices in active markets or present value techniques if quotes are unavailable. The determination of the fair value using present value techniques requires us to make projections and assumptions regarding the probability of a range of outcomes and the rates of interest used in the present value calculations. Any changes we make to these projections and assumptions could result in significant revisions to our evaluation of recoverability of our property, plant and equipment and the recognition of additional impairments.

Price Risk Management (Hedging)

Our net income and cash flows are subject to volatility stemming from changes in commodity prices and interest rates. In an effort to reduce the volatility of our cash flows, we have entered into derivative financial 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.

One of the factors that can affect our operating results each period is the price assumptions used to value our derivative financial instruments, which are reflected at their fair values on the balance sheet. We determine the fair value of our derivative instruments using present value methods or standard option valuation models with assumptions about commodity prices based on those observed in underlying markets. Changes in the methods or assumptions we use to calculate the fair value of our derivative instruments could have a material effect on our consolidated financial statements.

Recent Accounting Pronouncements

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

Item 7A. 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. All of our commodity derivatives are 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 2024. 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 commodities 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 December 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 Transportation segment and (iii) natural gas transportation basis risk in our Logistics and Transportation 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 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 our senior secured indebtedness that ranks equal in right of payment with liens granted in favor of our 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 December 31, 2019:

	Fair Value	Result of 10% Price Decrease	Result of 10% Price Increase
Natural gas	$ (84.0)	$ (35.6)	$ (132.3)
NGLs	78.0	116.1	40.0
Crude oil	(0.1)	21.6	(21.9)
Total	$ (6.1)	$ 102.1	$ (114.2)

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.

During the years ended December 31, 2019, 2018 and 2017, our operating revenues decreased by $4.1 million, $72.2 million, and $49.7 million, respectively, 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 liability position of $6.1 million at December 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. Our mark-to-market losses on transportation basis swaps more than offsets these expected gains, creating this net liability 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 TRP Revolver and the Securitization Facility. As of December 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 TRP Revolver and the Securitization Facility will also increase. As of December 31, 2019, we had $370.0 million in outstanding variable rate borrowings under the TRP Revolver and Securitization Facility. A hypothetical change of 100 basis points in the interest rate of our variable rate debt would impact our annual interest expense by $3.7 million based on our December 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 $21.0 million as of December 31, 2019. The range of losses attributable to our individual counterparties as of December 31, 2019 would be between $0.2 million and $21.8 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 December 31, 2019, our operating income would decrease by $8.6 million in the year of the assessment.

During the years ended December 31, 2019 and 2018, sales of commodities and fees from midstream services provided to Petredec (Europe) Limited comprised approximately 12% and 15% of our consolidated revenues. No customer comprised greater than 10% of our consolidated revenues in the year ended December 31, 2017.

Item 8. Financial Statements and Supplementary Data.

Our “Consolidated Financial Statements,” together with the report of our independent registered public accounting firm, begin on page F-1 in this Annual Report.

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure.

None.

Item 9A. 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 Annual Report. Based on such evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of December 31, 2019, 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.

Internal Control Over Financial Reporting

(a) Management’s Report on Internal Control Over Financial Reporting

Our Management’s Report on Internal Control Over Financial Reporting is included on page F-2 of this Annual Report and is incorporated herein by reference. Management concluded that our internal control over financial reporting was effective as of December 31, 2019.

(b) Changes in Internal Control Over Financial Reporting

There have been no changes in our internal control over financial reporting during our most recent fiscal quarter ended December 31, 2019 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information.

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

We are a limited partnership and, therefore, have no officers or directors. Unless otherwise indicated, references to our officers and directors in Items 10 through 14 of this Annual Report refer to the officers and directors of our general partner.

Management of Targa Resources Partners LP

Targa Resources GP LLC, our general partner, manages our operations and activities. Our general partner is not currently elected by our unitholders and is not subject to re-election on a regular basis in the future. Unitholders are not entitled to elect the directors of our general partner or directly or indirectly participate in our management or operation. Our general partner owes fiduciary duties to our unitholders, but our partnership agreement contains various provisions modifying and restricting its fiduciary duties. Our general partner is liable, as general partner, for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made expressly nonrecourse to it. Our general partner therefore may cause us to incur indebtedness or other obligations that are nonrecourse to it.

The directors of our general partner oversee our operations. Our general partner currently has ten directors. Targa GP Inc. elects all members to the board of directors of our general partner (the “Board”) and our general partner has eight directors that are independent as defined under the independence standards established by the NYSE. The NYSE does not require a listed limited partnership like us to have a majority of independent directors on the Board or to establish a compensation committee or a nominating/corporate governance committee.

The Board has a standing audit committee (the “Audit Committee”) that consists of three directors. The members of our Audit Committee are Mses. Fulton and Bowman and Mr. Redd. Ms. Fulton is the Chairman of this committee. Our board of directors has affirmatively determined that Mses. Fulton and Bowman and Mr. Redd are independent as described in the rules of the NYSE and the Exchange Act. Our board of directors has also determined that, based upon relevant experience, Ms. Fulton is an “audit committee financial expert” as defined in Item 407 of Regulation S-K of the Exchange Act. This committee oversees, reviews, acts on and reports on various auditing and accounting matters to our board of directors, including: the selection of our independent accountants, the scope of our annual audits, fees to be paid to the independent accountants, the performance of our independent accountants and our accounting practices. In addition, the Audit Committee oversees our compliance programs relating to legal and regulatory requirements and our cybersecurity efforts and measures. We have adopted an Audit Committee charter defining the committee’s primary duties in a manner consistent with the rules of the SEC and NYSE or market standards.

The compensation of our general partner’s executive officers is set by Targa, the indirect parent of our general partner, with the Board playing no role in the process. Compensation decisions relating to oversight of the long-term incentive plan described below, however, are made by the Board. While the Board may establish a compensation committee in the future, it has no current plans to do so.

All of our executive management personnel are employees of Targa Resources and devote their time as needed to conduct our and Targa’s business and affairs. These officers of Targa Resources manage the day-to-day affairs of our business. Because Targa’s only cash generating assets are direct and indirect partnership interests in us, we expect that our executive officers will devote a substantial majority of their time to our business. We expect the amount of time that the executive management personnel of our general partner devote to our business in future periods to be driven by the needs and demands of our ongoing business and business development efforts, which are likely to increase as our asset base and operations increase in size. However, depending on how our business develops and the nature of the business development efforts by executive management, the amount of time that the executive management team of our general partner devotes to our business may increase or decrease in future periods. We also utilize a significant number of employees of Targa Resources to operate our business and provide us with general and administrative services. We reimburse Targa for allocated expenses of operational personnel who perform services for our benefit, allocated general and administrative expenses and certain direct expenses. See “Reimbursement of Expenses of Our General Partner” included in this Item 10.

Directors, Executive Officers and Other Officers

Our general partner's directors hold office until the earlier of their death, resignation, removal or disqualification or until their successors have been elected and qualified. Officers serve at the discretion of the Board. There are no family relationships among any of our general partner's directors or executive officers. The following table shows information with respect to the current directors, executive officers and other officers of Targa Resources GP LLC as of February 20, 2020:

Name	Age	Position
Joe Bob Perkins	59	Chief Executive Officer and Director
James W. Whalen	78	Executive Chairman of the Board and Director
Matthew J. Meloy	42	President
Patrick J. McDonie	59	President – Gathering and Processing
D. Scott Pryor	57	President – Logistics and Transportation
Robert M. Muraro	43	Chief Commercial Officer
Jennifer R. Kneale	41	Chief Financial Officer
Paul W. Chung	59	Executive Vice President, General Counsel and Secretary
G. Clark White	60	Executive Vice President – Engineering and Operations
Julie H. Boushka	57	Senior Vice President and Chief Accounting Officer
Rene R. Joyce	72	Director
Charles R. Crisp	72	Director
Chris Tong	63	Director
Ershel C. Redd Jr.	72	Director
Laura C. Fulton	56	Director
Waters S. Davis, IV	66	Director
Robert B. Evans	71	Director
Beth A. Bowman	63	Director

Joe Bob Perkins has served as Chief Executive Officer and a director of the Company and our general partner since January 2012. Effective March 1, 2020, Mr. Perkins will be become Executive Chairman of the Board of the Company and our general partner and will resign from his position as Chief Executive Officer. He previously served as President of the Company between the date of its formation on October 2005 and December 2011. Prior to 2005, Mr. Perkins served predecessor Targa companies as President since their founding in 2003. Prior to that, Mr. Perkins served in various leadership roles within the energy industry across several different companies, had employment experience with companies operating in both the midstream and upstream sectors, and was a management consultant with McKinsey & Company working primarily in energy. Mr. Perkins' intimate knowledge of all facets of the Company, derived from his past services as President, Chief Executive Officer and director, coupled with his broad experience in the energy industry, and specifically in the midstream sector, his engineering and business educational background and his experience with the investment community enable Mr. Perkins to provide a valuable and unique perspective to the board on a range of business and management matters.

James W. Whalen has served as a director of the Company since its formation in October 2005 and of our general partner since February 2007. Mr. Whalen has also served as Executive Chairman of the Board of the Company and our general partner since January 2015. He will resign from his position as Executive Chairman of the Board, effective March 1, 2020. He also served as director of an affiliate of the Company during 2004 and 2005. Mr. Whalen previously served as Advisor to Chairman and CEO of the Company and our general partner between January 2012 and December 2014. He served as Executive Chairman of the Board of the Company between October 2010 and December 2011 and of our general partner between December 2010 and December 2011. He also served as President-Finance and Administration of the Company between January 2006 and October 2010 and our general partner between October 2006 and December 2010 and for various Targa subsidiaries since November 2005. Between October 2002 and October 2005, Mr. Whalen served as the Senior Vice President and Chief Financial Officer of Parker Drilling Company. Between January 2002 and October 2002, he was the Chief Financial Officer of Diversified Diagnostic Products, Inc. He served as Chief Commercial Officer of Coral Energy Holding, L.P. ("Coral") from February 1998 through January 2000. Previously, he served as Chief Financial Officer for Tejas Gas Corporation ("Tejas") from 1992 to 1998. Mr. Whalen brings a breadth and depth of experience as an executive, board member, and audit committee member across several different companies and in energy and other industry areas. His valuable management and financial expertise includes an understanding of the accounting and financial matters that the Company and industry address on a regular basis.

Matthew J. Meloy has served as President of the Company and our general partner since March 2018. Effective March 1, 2020, Mr. Meloy will become Chief Executive Officer and a director of the Company and our general partner and will resign from his position as President. Mr. Meloy previously served as Executive Vice President and Chief Financial Officer of the Company and our general partner between May 2015 and February 2018. He also served as Treasurer of the Company and our general partner until December

2015. He also served as Senior Vice President, Chief Financial Officer and Treasurer of the Company between October 2010 and May 2015 and of our general partner between December 2010 and May 2015. He also served as Vice President—Finance and Treasurer of the Company between April 2008 and October 2010, and as Director, Corporate Development of the Company between March 2006 and March 2008 and of our general partner between March 2006 and March 2008. He has served as Vice President—Finance and Treasurer of our general partner between April 2008 and December 15, 2010. Mr. Meloy was with The Royal Bank of Scotland in the structured finance group, focusing on the energy sector from October 2003 to March 2006.

Patrick J. McDonie has served as President—Gathering and Processing of the Company and our general partner since March 2018. Mr. McDonie previously served as Executive Vice President—Southern Field Gathering and Processing of the Company and our general partner between November 2015 and February 2018. He also served as President of Atlas Pipeline Partners GP LLC (“Atlas”), which was acquired by the Partnership in February 2015, between October 2013 and February 2015. He also served as Chief Operating Officer of Atlas between July 2012 and October 2013 and as Senior Vice President of Atlas between July 2012 and October 2013. He served as President of ONEOK Energy Services Company, a natural gas transportation, storage, supplier and marketing company between May 2008 and July 2012.

D. Scott Pryor has served as President—Logistics and Transportation of the Company and our general partner, since March 2018. Mr. Pryor previously served as Executive Vice President—Logistics and Marketing of the Company and our general partner between November 2015 and February 2018. He also served as Senior Vice President—NGL Logistics & Marketing of Targa Resources Operating LLC (“Targa Operating”) and various other subsidiaries of the Partnership between June 2014 and November 2015. He also served as Vice President of Targa Operating between July 2011 and May 2014 and has held officer positions with other Partnership subsidiaries since 2005.

Robert M. Muraro has served as Chief Commercial Officer of the Company and our general partner since March 2018. Mr. Muraro previously served as Executive Vice President—Commercial of the Company and our general partner between February 2017 and February 2018. He also served as Senior Vice President—Commercial and Business Development of Targa Midstream Services LLC (“Targa Midstream”) and various other subsidiaries of the Partnership between March 2016 and February 2017. He also served as Vice President—Commercial Development of Targa Midstream and various other subsidiaries of the Partnership between January 2013 and March 2016. He held the position of Director of Business Development between August 2004 and January 2013.

Jennifer R. Kneale has served as Chief Financial Officer of the Company and our general partner since March 2018. Ms. Kneale previously served as Vice President—Finance of the Company and our general partner between December 2015 and February 2018. She also served as Senior Director, Finance of the Company and our general partner between March 2015 and December 2015. She also served as Director, Finance of the Company and our general partner between May 2013 and February 2015. Ms. Kneale was with Tudor, Pickering, Holt & Co. in its energy private equity group, TPH Partners, from September 2011 to May 2013, most recently serving as Director of Investor Relations.

Paul W. Chung has served as Executive Vice President, General Counsel and Secretary of the Company since its formation in October 2005 and of our general partner since October 2006. He also served as an officer of an affiliate of the Company during 2004 and 2005. Mr. Chung served as Executive Vice President and General Counsel of Coral from 1999 to April 2004; Shell Trading North America Company, a subsidiary of Shell Oil Company (“Shell”), from 2001 to April 2004; and Coral Energy, LLC from 1999 to 2001. In these positions, he was responsible for all legal and regulatory affairs. He served as Vice President and Assistant General Counsel of Tejas from 1996 to 1999. Prior to 1996, Mr. Chung held a number of legal positions with different companies, including the law firm of Vinson & Elkins L.L.P.

G. Clark White has served as Executive Vice President—Engineering and Operations of the Company and our general partner since November 2015. Mr. White previously served as Senior Vice President—Field G&P of Targa Operating and various other subsidiaries of the Partnership between June 2014 and November 2015. He also served as Vice President of Targa Operating between July 2011 and May 2014 and has held officer positions with other Partnership subsidiaries since 2003.

Julie H. Boushka has served as Senior Vice President and Chief Accounting Officer of the Company and our general partner since March 2019. Ms. Boushka previously served as Vice President—Controller of the Company, our general partner and various subsidiaries of the Company between February 2017 and February 2019. She also served as Assistant Controller—Financial Accounting of the Company and our general partner between November 2016 and February 2017. Ms. Boushka served as a Senior Vice President for Financial Planning and the Chief Risk Officer for Columbia Pipeline Group (“CPG”) between June 2015 and August 2016, where she was responsible for the financial planning function and managing enterprise risk. She also served as the Business Unit Chief Financial Officer of CPG between May 2013 and June 2015, where she was responsible for the accounting and financial planning functions. Prior to that, Ms. Boushka spent approximately 18 years in various roles at El Paso Corporation (and its predecessor, Tenneco, Inc.), including accounting, financial reporting and business development.

Rene R. Joyce has served as a director of the Company since its formation in October 2005 and of our general partner since October 2006. Mr. Joyce previously served as Executive Chairman of the Board of the Company and our general partner between January 2012 and December 2014. He also served as Chief Executive Officer of the Company between October 2005 and December 2011 and our general partner between October 2006 and December 2011. He also served as an officer and director of an affiliate of the Company during 2004 and 2005 and was a consultant for the affiliate during 2003. Mr. Joyce is a director of Apache Corporation. Mr. Joyce served as a consultant in the energy industry from 2000 through 2003 providing advice to various energy companies and investors regarding their operations, acquisitions and dispositions. Mr. Joyce served as President of onshore pipeline operations of Coral Energy, LLC, a subsidiary of Shell from 1998 through 1999 and President of energy services of Coral, a subsidiary of Shell which was the gas and power marketing joint venture between Shell and Tejas, during 1999. Mr. Joyce served as President of various operating subsidiaries of Tejas, a natural gas pipeline company, from 1990 until 1998 when Tejas was acquired by Shell. As the founding Chief Executive Officer of the Company, Mr. Joyce brings deep experience in the midstream business, expansive knowledge of the oil and gas industry, as well as relationships with chief executives and other senior management at peer companies, customers and other oil and natural gas companies throughout the world. His experience and industry knowledge, complemented by an engineering and legal educational background, enable Mr. Joyce to provide the board with executive counsel on the full range of business, technical, and professional matters.

Charles R. Crisp has served as a director of the Company since its formation in October 2005 and of our general partner since March 2016. He also served as a director of an affiliate of the Company during 2004 and 2005. Mr. Crisp was President and Chief Executive Officer of Coral Energy, LLC, a subsidiary of Shell Oil Company from 1999 until his retirement in November 2000, and was President and Chief Operating Officer of Coral from January 1998 through February 1999. Prior to this, Mr. Crisp served as President of the power generation group of Houston Industries and, between 1988 and 1996, as President and Chief Operating Officer of Tejas. Mr. Crisp is also a director of Southern Company Gas (formerly known as AGL Resources Inc.), a subsidiary of The Southern Company, EOG Resources Inc. and Intercontinental Exchange Inc. Mr. Crisp brings extensive energy experience, a vast understanding of many aspects of our industry and experience serving on the boards of other public companies in the energy industry. His leadership and business experience and deep knowledge of various sectors of the energy industry bring a crucial insight to the board of directors.

Chris Tong has served as a director of the Company since January 2006 and of our general partner since March 2016. Mr. Tong served as a director of Kosmos Energy Ltd. from 2011 until September 2019. He served as Senior Vice President and Chief Financial Officer of Noble Energy, Inc. from January 2005 until August 2009. He also served as Senior Vice President and Chief Financial Officer for Magnum Hunter Resources, Inc. from August 1997 until December 2004. Prior thereto, he was Senior Vice President of Finance of Tejas Acadian Holding Company and its subsidiaries, including Tejas Gas Corp., Acadian Gas Corporation and Transok, Inc., all of which were wholly-owned subsidiaries of Tejas Gas Corporation. Mr. Tong held these positions from August 1996 until August 1997, and had served in other treasury positions with Tejas since August 1989. Mr. Tong brings a breadth and depth of experience as a chief financial officer in the energy industry, a financial executive, a director of other public companies and a member of other audit committees. He brings significant financial, capital markets and energy industry experience to the board.

Ershel C. Redd Jr. has served as a director of the Company since February 2011 and of our general partner since March 2016. Mr. Redd has served as a consultant in the energy industry since 2008 providing advice to various energy companies and investors regarding their operations, acquisitions and dispositions. Mr. Redd was President and Chief Executive Officer of El Paso Electric Company, a public utility company, from May 2007 until March 2008. Prior to this, Mr. Redd served in various positions with NRG Energy, Inc., a wholesale energy company, including as Executive Vice President—Commercial Operations from October 2002 through July 2006, as President—Western Region from February 2004 through July 2006, and as a director between May 2003 and December 2003. Mr. Redd served as Vice President of Business Development for Xcel Energy Markets, a unit of Xcel Energy Inc., from 2000 through 2002, and as President and Chief Operating Officer for New Century Energy's (predecessor to Xcel Energy Inc.) subsidiary, Texas Ohio Gas Company, from 1997 through 2000. Mr. Redd brings to the Company extensive energy industry experience, a vast understanding of varied aspects of the energy industry and experience in corporate performance, marketing and trading of natural gas and natural gas liquids, risk management, finance, acquisitions and divestitures, business development, regulatory relations and strategic planning. His leadership and business experience and deep knowledge of various sectors of the energy industry bring a crucial insight to the board of directors.

Laura C. Fulton has served as a director of the Company since February 2013 and of our general partner since March 2016. Ms. Fulton has served as the Vice President Finance of the American Bureau of Shipping since January 2020. Ms. Fulton served as the Chief Financial Officer of Hi-Crush Proppants LLC from April 2012 until December 2019 and Hi-Crush GP LLC, the general partner of Hi-Crush Partners LP, from May 2012 until May 2019 and its successor, Hi-Crush Inc., from May 2019 to December 2019. From March 2008 to October 2011, Ms. Fulton served as Executive Vice President, Accounting and then Executive Vice President, Chief Financial Officer of AEI Services, LLC ("AEI"), an owner and operator of essential energy infrastructure assets in emerging markets. Prior to AEI, Ms. Fulton spent 12 years with Lyondell Chemical Company in various capacities, including as general auditor responsible for internal audit and the Sarbanes-Oxley certification process, and as the assistant controller. Prior to that, she spent 11 years with Deloitte & Touche in public accounting, with a focus on audit and assurance. As a chief financial officer, general auditor and external auditor, Ms. Fulton brings to the company extensive financial, accounting and compliance process experience. Ms. Fulton's experience as a financial executive in the energy industry, including her positions with a publicly-traded company and master limited partnership, also brings industry and capital markets experience to the board.

Waters S. Davis, IV has served as director of the Company since July 2015 and of our general partner since March 2016. Mr. Davis has served as President of National Christian Foundation, Houston since July 2014. Mr. Davis was Executive Vice President of NuDevco LLC from December 2009 to December 2013. Prior to his employment with NuDevco, he served as President of Reliant Energy Retail Services from June 1999 to January 2002 and as Executive Vice President of Spark Energy from April 2007 to November 2009. He previously served as a senior executive at a number of private companies and as an advisor to a private equity firm, providing operational and strategic guidance. Mr. Davis also serves as a director of Milacron Holdings Corp. Mr. Davis brings expertise in the retail energy, midstream and services industries, which enhances his contributions to the board of directors.

Robert B. Evans has served as a director of the Company since March 2016 and of our general partner since February 2007. Mr. Evans is also a director of New Jersey Resources Corporation and One Gas, Inc. Mr. Evans was a director of Sprague Resources GP LLC until October 2018. Mr. Evans was the President and Chief Executive Officer of Duke Energy Americas, a business unit of Duke Energy Corp., from January 2004 until his retirement in March 2006. Mr. Evans served as the transition executive for Energy Services, a business unit of Duke Energy, during 2003. Mr. Evans also served as President of Duke Energy Gas Transmission beginning in 1998 and was named President and Chief Executive Officer in 2002. Prior to his employment at Duke Energy, Mr. Evans served as Vice President of marketing and regulatory affairs for Texas Eastern Transmission and Algonquin Gas Transmission from 1996 to 1998. Mr. Evans' extensive experience in the gas transmission and energy services sectors enhances the knowledge of the board in these areas of the oil and gas industry. As a former President and CEO of various operating companies, his breadth of executive experiences is applicable to many of the matters routinely facing the Partnership.

Beth A. Bowman has served as a director of the Company and our general partner since September 2018. Ms. Bowman has served as a director of Sprague Resources GP LLC, the general partner of Sprague Resources LP ("Sprague"), since October 2014, and she currently serves on the Audit Committee of Sprague. Ms. Bowman held management positions at Shell Energy North America (US) L.P. ("Shell") for 17 years until her retirement in September 2015. While at Shell, she held the roles of Senior Vice President of the West and Mexico and later as the Senior Vice President of Sales and Origination for Shell's North America business. Prior to joining Shell, Ms. Bowman held management positions at Sempra Energy Trading and Sempra's San Diego Gas & Electric utility in various areas including trading and marketing, risk management, fuel and power supply, regulatory, finance and engineering. Ms. Bowman also served on the board of the California Power Exchange and the board of the California Foundation of Energy and Environment from 2004 until 2015. Ms. Bowman's extensive energy industry background, including her experience in origination, commodities markets and risk management enhances the knowledge of the board in these areas of the oil and gas industry.

Reimbursement of Expenses of Our General Partner

Under the terms of our Partnership Agreement, we reimburse Targa for all direct and indirect expenses, as well as expenses otherwise allocable to us in connection with the operation of our business, incurred on our behalf, which includes certain operating and direct expenses, including compensation and benefits of operating personnel, and for the provision of various general and administrative services for our benefit. Targa performs centralized corporate functions for us, such as legal, accounting, treasury, insurance, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes, engineering and marketing. We reimburse Targa for the direct expenses to provide these services as well as other direct expenses it incurs on our behalf, such as compensation of operational personnel performing services for our benefit and the cost of their employee benefits, including 401(k), pension and health insurance benefits. Other than Targa's direct costs of being a public reporting company, substantially all of Targa's general and administrative costs have been, so long as Targa's only cash-generating assets consist of its interest in us, and will continue to be allocated to us. See "Item 13. Certain Relationships and Related Transactions, and Director Independence."

Board of Directors

Our general partner's board of directors consists of ten members. The general partner's board reviewed the independence of our directors using the independence standards of the NYSE and, based on this review, determined that Messrs. Joyce, Crisp, Evans, Redd, Tong and Davis and Mses. Fulton and Bowman are independent within the meaning of the NYSE listing standards currently in effect.

Corporate Governance

Code of Business Conduct and Ethics

Our general partner has adopted a Code of Ethics For Chief Executive Officer and Senior Financial Officers (the "Code of Ethics"), which applies to our general partner's Chief Executive Officer, Chief Financial Officer, Chief Accounting Officer, Controllers and all of our other senior financial and accounting officers, and our Code of Conduct (the "Code of Conduct"), which applies to officers, directors and employees of the Company and its subsidiaries, including our general partner. In accordance with the disclosure requirements of applicable law or regulation, we intend to disclose any amendment to, or waiver from, any provision of the Code of Ethics or Code of Conduct under Item 5.05 of a current report on Form 8-K.

Available Information

We make available, free of charge within the "Corporate Governance" section of our website at *http://www.targaresources.com* and in print to any unitholder who so requests, our Corporate Governance Guidelines, Code of Ethics, Code of Conduct and the Audit Committee Charter. Requests for print copies may be directed to: Investor Relations, Targa Resources Partners LP, 811 Louisiana, Suite 2100, Houston, Texas 77002 or made by telephone by calling (713) 584-1000. The information contained on or connected to our internet website is not incorporated by reference into this Annual Report and should not be considered part of this or any other report that we file with or furnish to the SEC.

Corporate Governance Guidelines

Our general partner's board of directors has adopted corporate governance guidelines in accordance with the corporate governance rules of the NYSE.

Executive Sessions of Non-Management Directors

Our non-management directors meet in executive session without management participation at regularly scheduled executive sessions. These meetings are chaired by Mr. Crisp.

Interested parties may communicate directly with our non-management directors by writing to: Non-Management Directors, Targa Resources Partners LP, 811 Louisiana, Suite 2100, Houston, Texas 77002.

Item 11. Executive Compensation.

COMPENSATION DISCUSSION AND ANALYSIS

EXECUTIVE COMPENSATION

Overview

Neither we nor our general partner directly employ any of the persons responsible for managing our business. Any compensation decisions that are required to be made by our general partner will be made by the board of directors of our general partner, which does not have a compensation committee. All of our general partner's executive officers are also employees of Targa.

The following Compensation Discussion and Analysis (CD&A) is presented from the perspective of the compensation committee (the "Compensation Committee") of the Targa board of directors and discusses our general partner's named executive officers in their roles as officers of Targa. The elements of compensation and the Compensation Committee's decisions with respect to determination on payments are not subject to approval by the board of directors of our general partner or the board of directors of Targa. All members of the board of directors of our general partner are members of the Targa board of directors. As used in this CD&A (other than in this "Overview"), references to "our," "we," "us," the "Company," and similar terms refer to Targa, references to the "Board" or "Board of Directors" refers to the Targa board of directors.

2019 CD&A At-A-Glance

This year's CD&A reviews the objectives and elements of Targa's executive compensation program and discusses the 2019 compensation earned by our Named Executive Officers (NEOs). It also explains the actions the Compensation Committee took based on its ongoing commitment to consider shareholder feedback and to ensure our senior leadership team remains focused on the seamless execution of our business strategy and delivering shareholder value over the long-term. During 2019 and early 2020, we:

✓Conducted a major shareholder outreach campaign, with a significant focus on executive compensation matters	•Reached out to each of our top 50 shareholders, representing more than 80% of shares outstanding
✓Continued our senior leadership transition plan, which is part of our comprehensive, ongoing multi-year succession planning strategy overseen by our Board of Directors	•Announced the transitions of Mr. Perkins, 2019 CEO, to Executive Chairman (succeeding Mr. Whalen) and Mr. Meloy, 2019 President, to CEO (succeeding Mr. Perkins)
✓Did not grant any special, one-time equity awards	•Reinforced that special, one-time equity award grants are not a regular feature of our program and are not expected to be a material feature of our program going forward
✓Engaged a new independent compensation consulting firm	•Retained Pearl Meyer to gain further insight on current pay practices to ensure that our program effectively balances competitive market practices, investor expectations, best-practice governance standards and our business strategy
✓Updated the compensation peer group to better align with market	•Reduced number of peer companies by consolidating to a simplified, single group
✓Implemented a simplified, single, three-year performance period for long-term equity incentives	•PSUs are earned and vest at the end of a three-year performance period based on relative Total Shareholder Return (TSR)
✓Set target payout under our long-term incentive plan at 55th percentile	•PSUs are not earned at target unless we beat the median of our performance peers

✓Adopted a formal, comprehensive clawback policy that better aligns with best practices	•All performance-based incentive awards or payments (both short term cash and long-term equity) for our Section 16 officers may be subject to clawback in the event of restatement of financial results or other events that negatively impact our company
✓Improved our compensation disclosure with respect to annual incentives	•Provided clearer, simplified, more transparent and shareholder-friendly communication about how annual incentives are determined
✓Eliminated single-trigger equity vesting upon a change-in-control (CIC) for our NEOs	•All equity incentive awards to our NEOs starting in 2020 will have double-trigger vesting following a CIC

More details about our shareholder outreach efforts, our 2019 business achievements and the resulting compensation actions taken by the Compensation Committee are in the following pages of our CD&A.

2019 Named Executive Officers

Name	Position as of December 31, 2019
Joe Bob Perkins	Chief Executive Officer (CEO)
Matthew J. Meloy	President
Jennifer R. Kneale	Chief Financial Officer (CFO)
Patrick J. McDonie	President – Gathering and Processing
D. Scott Pryor	President – Logistics and Transportation
Robert M. Muraro	Chief Commercial Officer

Leadership Transition

As part of a leadership transition plan announced in July 2019, Matthew J. Meloy will become our Chief Executive Officer effective March 1, 2020 at which time Joe Bob Perkins, our former Chief Executive Officer, will become Executive Chairman of our Board of Directors.

Some of the changes discussed in this CD&A regarding compensation opportunities for 2020 reflect this leadership transition and continued work by the Committee to ensure that compensation opportunities truly reflect market median practice for each of our NEOs.

BOARD RESPONSIVENESS TO SHAREHOLDER FEEDBACK

We regularly meet with our shareholders to discuss business topics, seek feedback on our performance, and address other matters such as executive compensation. We increased the focus and intensity of our stockholder engagement as a result of our most recent say-on-pay vote, which yielded approximately 60% support for our executive compensation program. With a desire to broaden our perspective and improve our communications related to executive compensation programs and decisions, governance, sustainability and other related matters, we plan to engage in annual outreach with our largest shareholders specifically focused on those topics. As part of this annual outreach in 2019 we contacted our 50 largest stockholders, representing more than 80% of our outstanding shares as of June 30, 2019. We held discussions with 25 shareholders aggregating to more than 60% of our outstanding shares. These discussions typically included some combination of our lead independent director (who is also a member of the Compensation Committee), our CEO, CFO, and Senior Director of Finance and Investor Relations. Insights from these meetings were shared with our full Board. Through these exchanges, we gained greater appreciation for our shareholder’s views on how we are managing our programs, where we can strengthen our plan designs, and where we can be clearer in our disclosures about how certain aspects of our compensation programs work.

In the third quarter of 2019 the Compensation Committee retained Pearl Meyer, a leading independent compensation consulting firm, to gain further insight on current pay practices and to help ensure that our approach going forward effectively balances competitive market practices, stockholder expectations, best-practice governance standards, and our business strategy. Pearl Meyer was involved in our preparations for the shareholder outreach discussed above, and they were also involved in assessing the feedback gathered from those discussions.

The result of these efforts includes changes to our programs that more closely align with market best practices and reflect shareholder feedback. We executed on an aggressive, yet thoughtful, implementation timeline to respond to our stakeholders’ priorities, while mitigating any avoidable disruption to the business. We believe those efforts are well summarized in the table below, which includes an overview of feedback from our key stakeholders, and our response to that feedback:

What We Heard	How We Responded
Concern regarding large one-time grant during 2018	These types of awards are not part of our regular practice. No such one-time awards were granted to any executive officer during 2019 and are not expected to be a material feature of our program going forward.
Annual incentives are discretionary and difficult to understand	In this CD&A, we have improved and simplified the description of how annual incentives work and have provided more clarity around the design, rigor and administration of the 2019 annual incentive plan. We have also applied formal weights to specific performance categories, with an emphasis on enterprise-wide financial performance, in order to improve transparency.
Including multiple annual performance periods in the assessment of performance for our long-term performance share unit (PSU) plan was viewed by some observers as partially short term	Starting with awards granted after January 1, 2020, PSUs under the long-term equity incentive plan will vest based on Total Shareholder Return (TSR) relative to a performance peer group at the end of a single three-year performance measurement period.
There needs to be a sufficiently robust market-based clawback policy	Effective December 5, 2019, our Board adopted a market-based clawback policy such that all performance-based incentive awards or payments (both short term cash and long term equity) for our Section 16 officers may be subject to clawback in the event of a material restatement of financial results or conduct by a Section 16 officer that materially and negatively impacts our stock or financial performance
Using multiple peer groups for compensation comparisons seems overly complicated	For 2020, we developed a simplified Compensation Peer Group to more closely align with our industry and operations, and to provide a more focused market reference point with a better overall correlation to our organization.
Single-trigger vesting of equity upon a CIC is no longer typical market practice	Beginning with 2020 grants, all equity incentive awards to our NEOs will have double-trigger vesting in the context of a CIC

2019 EXECUTIVE COMPENSATION PROGRAM SNAPSHOT

Compensation Philosophy and Guiding Principles

The philosophy underlying our executive compensation program is to employ the best leaders in our industry to ensure we execute on our business goals, promote both short-and long-term profitable growth of the Company and create long-term shareholder value. As such, our program is grounded in the following principles:

- ***Competition with Peers.*** Our executive compensation program should enable us to attract and retain key executives by providing a total compensation program that is competitive with the market in which we compete for executive talent, which encompasses not only diversified midstream companies but also other companies in the energy industry.

- ***Accountability for Performance***. Our executive compensation program should ensure an alignment between our strategic, operational and financial performance and the total compensation received by our NEOs. This includes providing compensation for performance that reflects individual and company performance both in absolute terms and relative to our Peer Group.

- ***Alignment with Shareholder Interests***. Our executive compensation program should ensure a balance between short-term and long-term compensation while emphasizing at-risk or variable compensation. Providing compensation that is based on our performance acts as a valuable means of supporting our strategic goals and business objectives and aligning the interests of our NEOs with those of our shareholders.

Elements of Pay

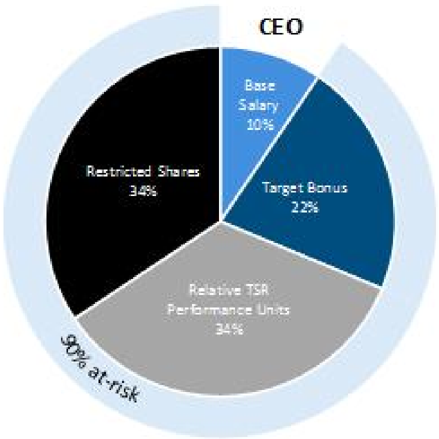
Our compensation philosophy is supported by the following principal pay elements:

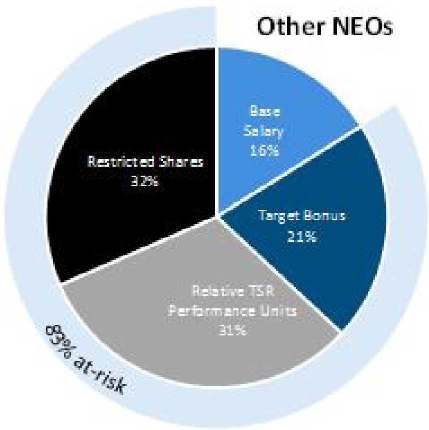
Element	Key Characteristics	Grounding Principles		
		Competition	Accountability	Shareholder Alignment
Base Salary	•Annual fixed cash compensation •Critical factor in attracting and retaining qualified talent	✓		
Annual Incentives	•Annual variable cash award •Awards are tied to achievement of key financial, operational, and strategic objectives •Based upon a rigorous, holistic evaluation of performance, ultimately subject to Compensation Committee business judgement	✓	✓	✓
Long-Term Incentives	•Provided through a combination of: •50% Performance share units (PSUs) •50% Restricted stock units (RSUs) •Promotes alignment with shareholders by tying a majority of NEO compensation to creation of long-term value and by encouraging NEOs to build meaningful equity ownership stakes	✓	✓	✓

Pay Mix

We remain committed to our emphasis on at-risk, incentive-based pay – with payouts tied to our performance against several strategic and financial objectives including relative TSR, and realizable pay heavily dependent upon our ability to grow shareholder value. The charts below show the mix of total direct compensation of our CEO and our other NEOs for 2019. These charts illustrate that a majority of NEO total direct compensation is at-risk (90% for our CEO and an average of 84% for our other NEOs).

TARGET TOTAL DIRECT COMPENSATION MIX

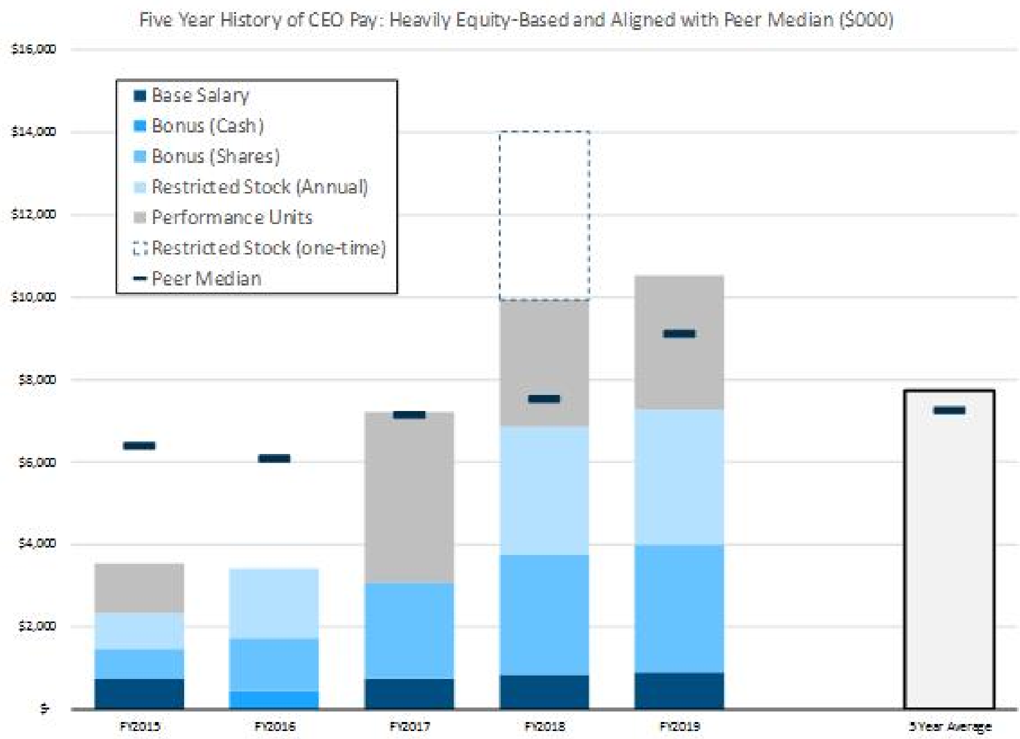




CEO Compensation at a Glance

Movement toward better alignment with market.

The chart below provides a five-year comparison of CEO actual total compensation to peer group median levels of CEO compensation. As shown, CEO compensation has historically been heavily equity-based, including bonuses typically taken in the form of equity. The pattern of CEO pay shown on the chart reflects in part the Compensation Committee's efforts over time to better align compensation opportunities for our CEO with the market median.



The market median reference points shown on the chart reflect peer group compensation data provided to the Compensation Committee in each year by the Committee's independent consultant.

The Compensation Committee generally desires to be competitive at the market median for total compensation opportunities. Changes to pay levels discussed in this CD&A reflect in part the Committee's efforts to align NEO compensation more closely with the market median.

Good Governance Foundation

The following practices and policies in our executive compensation program promote sound compensation governance and align the interests of our shareholders and executives:

What We Do	What We Don't Do
✓Compare total CEO compensation to industry peers ✓Pay a majority of NEO compensation in the form of long-term incentives ✓Tie performance-based units to relative TSR ✓Maintain a comprehensive clawback policy aligned with industry norms* ✓Complete an annual compensation risk assessment ✓Maintain executive and director share ownership guidelines ✓Retain an independent consultant to advise the Committee	•No employee contracts •No single-trigger change-in-control severance arrangements •No single-trigger change-in-control vesting for NEO equity awards* •No excise tax gross-ups •No perquisites or supplemental benefits not generally available to other employees •No hedging or purchasing of Company stock on margin •No executive compensation practices that promote excessive risk

*New for 2020

Sustainability and ESG

As an energy infrastructure company focused on the transportation and storage of energy products, our operations are essential to the delivery of energy efficiently, safely, and reliably across the United States. At Targa, we have invested billions of dollars each year to build new and expanded assets to deliver energy products that sustain and enhance the quality of life of our citizenry.

We strive to conduct our business safely and with integrity, creating lasting benefits to our stakeholders, including our investors, lenders, customers, employees, business partners, regulators and the communities in which we live and work. The Company's performance on sustainability factors played a role in 2019 compensation decisions and will continue to play a role in the Compensation Committee's evaluation of annual incentive compensation.

Throughout our organization, *from the top down*, we are committed to maintaining and operating our assets safely, efficiently, and in an environmentally responsible manner. This is a commitment that starts with and is maintained by our Board of Directors, where the full Board of Directors is committed to holding the senior management team accountable for upholding commitments to continued efforts around sustainability and ESG, including through administration of the Company's annual incentive program.

We invite you to review our Sustainability Report, which is available on the Company's website at http://www.targaresources.com/sustainability/sustainability-report.

WHAT GUIDES OUR PROGRAM

The Decision Making Process

The Role of the Compensation Committee. The Compensation Committee oversees the executive compensation program for our NEOs. The Compensation Committee is comprised of independent, non-employee members of the Board. The Compensation Committee works very closely with its independent consultant and senior management to examine the effectiveness of the Company's executive compensation program throughout the year. Details of the Compensation Committee's authority and responsibilities are specified in the Compensation Committee's charter, which may be accessed at our website, www.targaresources.com, by clicking "Investors," and then "Corporate Governance."

The Role of Senior Management. Members of our senior management team attend regular meetings where executive compensation, Company and individual performance, and competitive compensation levels and practices are discussed and evaluated. Only the Compensation Committee members are allowed to vote on decisions regarding NEO compensation.

The CEO and President review their recommendations pertaining to NEO pay with the Compensation Committee providing transparency and oversight. Decisions on non-NEO pay are made by the CEO and President. The CEO and President do not participate in the deliberations of the Compensation Committee regarding their own compensation. The members of the Compensation Committee make all final determinations regarding CEO and NEO compensation.

The Role of the Independent Consultant. The Compensation Committee has the authority to engage and retain an independent compensation consultant to provide independent counsel and advice. At least annually, the Compensation Committee formally conducts an evaluation as to the effectiveness of the independent compensation consultant and periodically requests proposals from other potential consulting firms to ensure the independent compensation consultant is meeting its needs. For 2019, the Compensation Committee continued its engagement with BDO USA, LLP ("BDO") as its independent compensation consultant for matters related to executive and non-management director compensation. BDO's engagement ended in July 2019, and then the Compensation Committee retained the services of Pearl Meyer as its independent compensation consultant in September 2019 for the remainder of 2019 and for 2020.

Pearl Meyer was engaged in part to support the Compensation Committee's efforts to conduct a comprehensive analysis of the current executive compensation program, which was in direct response to shareholder feedback following the Company's 2019 Annual Meeting of Stockholders. Pearl Meyer was selected as the independent consultant after an extensive review process conducted by the Compensation Committee.

The Compensation Committee assessed the independence of BDO in 2018 and Pearl Meyer in 2019, as required under NYSE listing rules. The Compensation Committee has also considered and assessed all relevant factors, including but not limited to those set forth in Rule 10C-1(b)(4)(i) through (vi) under the Exchange Act, that could give rise to a potential conflict of interest with respect to the compensation consultants described above. Based on this review, we are not aware of any conflicts of interest raised by the work performed by BDO or Pearl Meyer that would prevent the consultants from serving as an independent advisor to the Compensation Committee.

The Role of Market References in Setting Compensation

2019 Compensation Peer Group. For purposes of setting compensation levels for 2019, the Compensation Committee worked with its independent compensation consultant, BDO, to review market surveys for similarly-sized companies and the compensation peer group compiled from public filings data to provide a reference and framework for decisions about the base salary and target annual and long-term incentives to be provided to each NEO. The Compensation Committee considers this information carefully and generally desires to be competitive at the market median for total compensation opportunities. However, in setting pay levels of our NEOs, the Committee considers a variety of additional factors, including individual performance, competencies, skills, future potential, prior experience, scope of responsibility and accountability within the organization.

Consistent with our historic practices, the 2019 compensation peer group used a combination of three comparator groups: (1) midstream companies, (2) exploration and production companies (E&Ps), and (3) energy utilities. These types of companies provided relevant reference points because they have similar or related operations, compete in the same or similar markets, face similar regulatory challenges and require similar skills, knowledge and experience of their executive officers as we require of our NEOs.

2019 Compensation Peer Group Companies

Midstream Companies	E&Ps	Energy Utilities
Buckeye Partners, L.P.	Apache Corporation	Ameren Corporation
Enable Midstream Partners, L.P.	Cabot Oil & Gas Corporation	Atmos Energy Corporation
Enbridge Energy Partners, L.P.	Chesapeake Energy Corporation	CenterPoint Energy, Inc.
Energy Transfer Equity, L.P.	Cimarex Energy Company	DTE Energy Company
EnLink Midstream Partners, L.P.	Concho Resources, Inc.	Enbridge Inc.
Enterprise Products Partners L.P.	Continental Resources, Inc.	Entergy Corporation
Genesis Energy, L.P.	Devon Energy Corporation	EQT Corporation
Kinder Morgan, Inc.	Diamondback Energy, Inc.	MDU Resources Group, Inc.
Magellan Midstream Partners, L.P.	EOG Resources, Inc.	National Fuel Gas Company
NuStar Energy L.P.	Hess Corporation	NiSource Inc.
ONEOK, Inc.	Marathon Oil Corporation	Public Service Enterprise Group, Inc.
Plains GP Holdings, L.P.	Murphy Oil Corporation	Sempra Energy
Tallgrass Energy Partners, LP	Newfield Exploration Company	The Southern Company
Williams Companies, Inc.	Noble Energy, Inc.	TransCanada Corporation
	Parsley Energy, Inc.	Xcel Energy Inc.
	Pioneer Natural Resources Company	
	QEP Resources, Inc.	
	Range Resources Corporation	
	SM Energy Company	
	Southwestern Energy Company	
	WPX Energy, Inc.	

2020 Compensation Peer Group. For purposes of setting compensation levels for 2020 and in connection with our goal to improve our compensation programs, during 2019 the Compensation Committee worked closely with Pearl Meyer and senior management to develop a new peer group. This revised compensation peer group is more closely aligned with the Company's industry classification and provides a single comparator group with an industry composition that is better correlated to our organization.

The 2020 compensation peer group consists of a mix of 18 midstream companies and E&Ps.

2020 Compensation Peer Group	
Buckeye Partners, L.P.	Magellan Midstream Partners, L.P.
Cheniere Energy, Inc.	Marathon Oil Corporation
Concho Resources, Inc.	Noble Energy, Inc.
Crestwood Equity Partners, L.P.	NuStar Energy L.P.
Devon Energy Corporation	ONEOK, Inc.
Energy Transfer Equity, L.P.	Parsley Energy, Inc.
Enterprise Products Partners L.P.	Pioneer Natural Resources Company
EnLink Midstream Partners, L.P.	Plains All American Pipeline, L.P.
Kinder Morgan, Inc.	Williams Companies, Inc.

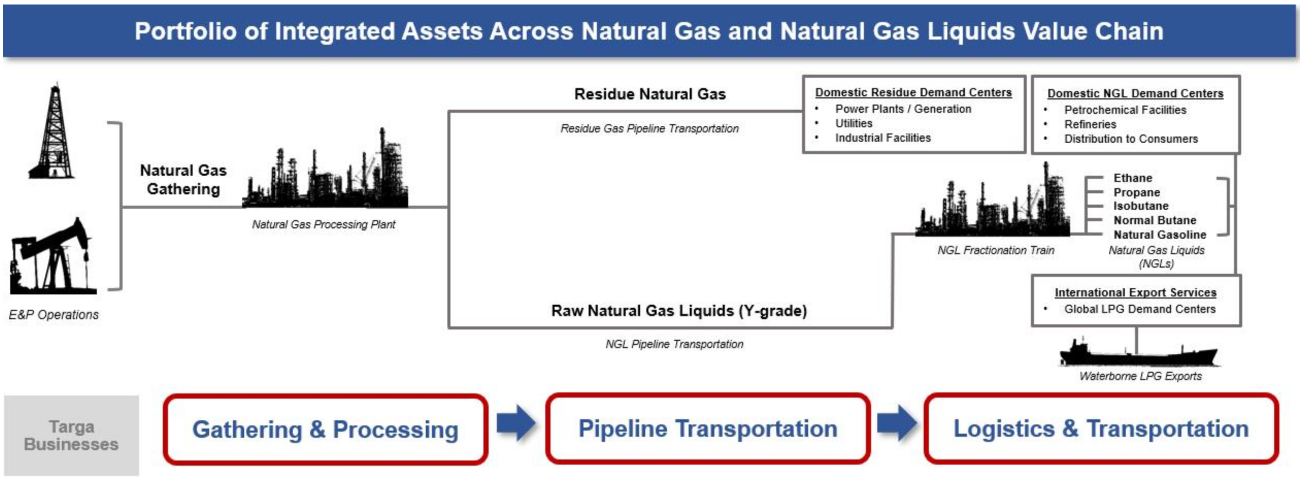
2020 Peer Data ($M) – Key Measures (1)			
	Revenue	*Assets*	*Total Enterprise Value*
75th Percentile	$10,822	$32,868	$45,600
50th Percentile	$7,236	$20,581	$21,748
25th Percentile	$4,117	$10,005	$12,163
Targa	$8,980	$17,569	$18,242
Percentile Rank	63rd	60th	41st

(1) As presented to the Compensation Committee in September 2019. Source: S&P Capital IQ

2019 BUSINESS OVERVIEW

The transition of Targa into a fully integrated midstream company with scale and asset diversity is largely complete, with 2019 representing the key inflection point in our corporate life cycle. Since early 2017, we placed in-service approximately $4 billion of projects, including Grand Prix, one of the most strategic projects since our inception, which directly links much of our Gathering and Processing business with other parts of our Downstream business. Grand Prix had a gross cost of approximately $2 billion and is the single largest project in our history, placed in-service largely on-time and on-budget, with significant volumes flowing immediately.

As we look forward, the next phase for Targa is to optimize our existing asset base, and to continue to invest along our core value chain.



2019 EXECUTIVE COMPENSATION PROGRAM IN DETAIL

Base Salary

Base salary represents annual fixed compensation and is a standard element of compensation necessary to attract and retain executive leadership talent. In making base salary decisions, the Compensation Committee considers the CEO's and President's recommendations, as well as each NEO's position and level of responsibility within the Company. The Compensation Committee takes into account factors such as relevant market data as well as individual performance and contributions.

For 2019, the Compensation Committee authorized base salary increases for all of the NEOs in order to align the total direct compensation of these individuals more closely with the total direct compensation provided to similarly situated executives at companies within our 2019 Peer Group, considering company size, and to reflect professional growth and the assumption of additional responsibilities. The 2019 base salary rates for our NEOs were as follows:

NEO	Prior Salary	Base Salary Effective March 1, 2019	Percent Increase (Approximate)
Joe Bob Perkins	$850,000	$900,000	6%
Matthew J. Meloy	525,000	600,000	14%
Jennifer R. Kneale	350,000	400,000	14%
Patrick J. McDonie	475,000	500,000	5%
D. Scott Pryor	475,000	500,000	5%
Robert M. Muraro	450,000	500,000	11%

Changes in base salary for 2020 are largely reflective of change in role as part of our leadership transition, and a desire to ensure that total compensation opportunities for 2020 are better aligned with market median practice for each of our NEOs. The March 1, 2020 base salary rates for our current NEOs are as follows:

NEO	Position as of March 1, 2020	Base Salary Effective March 1, 2020	Percent Increase/ (Decrease)
Matthew J. Meloy	CEO	$875,000 (1)	46%
Joe Bob Perkins	Executive Chairman	750,000 (2)	(17%)
Jennifer R. Kneale	CFO	575,000 (3)	44%
Patrick J. McDonie	President — G&P	525,000	5%
D. Scott Pryor	President — Downstream	525,000	5%
Robert M. Muraro	Chief Commercial Officer	525,000	5%

(1) Mr. Meloy's base salary increase reflects the significant expansion of responsibilities that he will take on as the CEO following March 1, 2020.

(2) Mr. Perkins' base salary decrease reflects his transition to the Executive Chairman role effective March 1, 2020.

(3) Ms. Kneale's base salary increase reflects the multi-year transition of her compensation to a level closer to similarly situated officers in connection with her appointment as Chief Financial Officer on March 1, 2018 and reflects the continued expansion of her responsibilities.

Annual Incentives

For 2019, our NEOs were eligible to receive annual incentive awards under the 2019 Annual Incentive Compensation Plan (the "2019 Bonus Plan"), which was approved by the Compensation Committee in January 2019. The funding of the bonus pool and the payment of individual bonuses to executive management, including our NEOs, are subject to the business judgement of the Compensation Committee (following recommendations from our CEO) and will generally be determined near or following the end of the year to which the bonus relates.

Target Bonus Amounts. Target bonus opportunities are expressed as a percentage of base salary and were established based on the NEO's level of responsibility and ability to impact overall results. The Compensation Committee also considers market data in setting target bonus amounts. The 2019 target bonus opportunities were as follows:

NEO	2019 Target Bonus (as a % of Base Salary)	2019 Target Bonus ($)	2020 Target Bonus (as a % of Salary)
Joe Bob Perkins	230%	$2,070,000	125%
Matthew J. Meloy	200%	1,200,000	200%
Jennifer R. Kneale	100%	400,000	100%
Patrick J. McDonie	100%	500,000	100%
D. Scott Pryor	100%	500,000	100%
Robert M. Muraro	100%	500,000	100%

2019 Bonus Plan Funding Levels. Annual bonus awards are based upon a rigorous evaluation of results across a variety of financial, operational and strategic categories. Performance was measured against a combination of pre-established goals and key strategic business priorities within these categories and assessed based on a holistic evaluation by the Compensation Committee that reflects the complexity of our business and our desire to ensure that decision-making over the short-term remains focused on producing sustainable growth over the long term.

Success levels are evaluated based on past norms, expectations for growth, and unanticipated obstacles or opportunities that arise. Each of the categories in the plan are now given specific weightings: financial (60%), operational (30%), and sustainability (10%).

At the end of the performance year, the Compensation Committee determines the total amount to be allocated to the bonus pool based on its assessment of the Executive Management team's achievements relative to the pre-established goals and our overall results for the year.

Evaluation of 2019 Performance

Our evaluation of performance in the annual incentive program includes consideration of performance on multiple factors within three general categories and with a safety category overlay:

Category	What it includes	Why it is important
Financial Performance	•Adjusted EBITDA •Balance sheet management	Adjusted EBITDA and balance sheet management together emphasize the importance of profitable growth grounded in prudent fiscal management
Operational Performance	•Volume growth •Commercial execution •Capital discipline •Project execution	Stresses the importance of operational excellence and optimization of asset utilization through increasing volumes, while focused on commercial execution and capital discipline – key drivers of value creation
Sustainability	•Talent management and development •Environmental, social and governance (ESG)	Promotes focus on investment in human capital and on incorporating the interests of all key stakeholders in the execution of our business strategy to help ensure that annual performance leads to sustainable long-term growth
Safety	•A holistic scorecard including quantitative and qualitative evaluation of incident rates, severity, process improvement, etc. •Operates outside plan as a modifier that can reduce plan payout if performance is below expectations	Stresses critical nature of safe operations and reinforces philosophy that strong safety performance is an expectation and not a justification for increased incentive compensation

The table below provides the more specific items within the first three general categories that our Compensation Committee utilized when setting and determining the 2019 bonuses.

Category	Priorities/Goals	Achievements	Level of Performance
Financial Performance (60%)	**EBITDA Goal:** **$1,300 million**	•$1,436 million adjusted EBITDA achievement, despite 15% drop in natural gas and 33% drop in NGL prices during year •Highest EBITDA in Targa's history	Far Exceeds
	Balance Sheet Management: •Minimize external public equity needs •Maintain adequate liquidity to fund ongoing growth program	•Raised $1.7 billion of capital at accretive values (higher than comparable trading multiples) from (i) sale of a 45% interest in Badlands and (ii) sale of an equity method investment •No equity issued for 2019, self-funded for equity capital •Raised $2.5 billion from two senior notes offering at attractive terms in volatile market	Exceeds
Operational Performance (30%)	**Volume Growth Goal:** •20% Permian •10% total Field G&P Grand Prix •Exceed initial expectations for volumes	•Permian: 29% increase in 2019 •Total Field G&P: 12% increase in 2019 •Grand Prix volumes for 2019 were substantially higher than initial expectations	Far Exceeds
	Capital Spending Growth Capital: •$2.3 - $2.4 billion of growth capex •Improve oversight, process on efficiency of capital spending	•Growth capex of just under $2.3 billion •New planning/budgeting approach focused on capital allocation •Implemented new internal processes to provide top-down oversight on spending	Meets
	Commercial Execution: Focus on deals that leverage our integrated platform and increase our fee-based margin	•Successfully executed additional third-party transportation and fractionation contracts of significant size and value •Fee based margin increased from 70% in 2018 to 80% in 2019	Exceeds
	Commercial Execution: Complete 2019 growth program safely and on time	•Placed in service over $4 billion of new projects within budget expectations in the aggregate with strong timing and budgetary execution despite regulatory and other challenges	Meets
Sustainability (10%)	**Talent management and development** **Environmental impact**	•Maintained necessary staffing levels and held turnover at 12% flat despite tight labor market •Added over 150 additional headcount for new facilities •Completed Targa's initial sustainability ESG report	Meets

***2019 Bonus Plan Payouts*.** Based on the assessment described above for 2019, the Compensation Committee arrived at an annual bonus pool equal to 1.6 times the target level under the 2019 Bonus Plan**.** The Compensation Committee considered the Company's safety performance as part of their overall evaluation. Our safety performance for 2019 included improvements in process and communication and reduction in overall incident rate, but also included an increase in severity. As a result of their review of safety performance, the Compensation Committee did not apply a factor to the calculated 1.6 payout shown in the table below.

	Consolidated Performance	Payout Factor	Weight	Weighted Factor
Financial	Far Exceeds	1.8	60%	1.1
Operational	Exceeds	1.4	30%	0.4
Sustainability	Meets	1.0	10%	0.1
TOTAL CALCULATED PAYOUT				**1.60**

***Individual Performance Multiplier*.** The Compensation Committee also evaluated the executive group and each officer's individual performance for the year and determined that there were no special circumstances that would be quantified applicable to any named executive officer's performance for 2019. As a result, the Compensation Committee determined that a performance multiplier of 1.0x should be applied to each named executive officer for 2019 based on the officer's individual performance and performance as part of the executive team.

***Settlement of 2019 Bonus Awards*.** The following table reflects the actual awards received by our NEOs under the 2019 Bonus Plan:

NEO	Target Bonus ($)	Individual Performance Factor	Company Performance Factor	Actual Bonus Paid (Cash)	Actual Bonus Paid (Shares)(1)
Joe Bob Perkins	$2,070,000	1.00	1.6	$ —	$3,312,000
Matthew J. Meloy	1,200,000	1.00	1.6	1,920,000	—
Jennifer R. Kneale	400,000	1.00	1.6	640,000	—
Patrick J. McDonie	500,000	1.00	1.6	800,000	—
D. Scott Pryor	500,000	1.00	1.6	800,000	—
Robert M. Muraro	500,000	1.00	1.6	800,000	—

(1) Mr. Perkins took 100% of this approved 2019 bonus in the form of restricted stock units that vest one year from the date of grant.

***2020 Target Bonus Opportunities*.** The table below summarizes target bonus opportunities for our NEOs for 2020.

NEO	Position as of March 1, 2020	2020 Target Bonus (as a % of Base Salary)	2020 Target Bonus ($)
Matthew J. Meloy	CEO	200%	$1,750,000
Joe Bob Perkins	Executive Chairman	125%	937,500
Jennifer R. Kneale	CFO	100%	575,000
Patrick J. McDonie	President — G&P	100%	525,000
D. Scott Pryor	President — Downstream	100%	525,000
Robert M. Muraro	Chief Commercial Officer	100%	525,000

Long-Term Equity Incentives

Equity compensation directly aligns the interests of the NEOs with those of our stockholders. In 2019, the Company granted equity compensation under our Stock Incentive Plan as follows:

Type of Equity Award	Weight	Description
Performance Share Units (PSUs)	50%	Vest at the end of three years contingent on the achievement of the Company's total shareholder return (TSR) relative to the TSR of a specified comparator group of publicly-traded midstream companies (the "LTIP Peer Group") measured over designated periods
Restricted Stock Units (RSUs)	50%	Vest in full at the end of a three-year period based solely on continued service; RSUs help to secure and retain executives and instill an ownership mentality

Target long-term equity incentive awards are expressed as a total dollar value based on a percentage of the NEO's base salary. For awards granted in 2019, the specified percentage of each NEO's base salary used for purposes of determining the amount of long-term equity incentive awards granted and the corresponding dollar values are set forth in the following table:

NEO	Target Award (as a % of Base Salary)	Target Award ($ Value)	Number of RSUs Granted (#)	Number of PSUs Granted (#)
Joe Bob Perkins	725%	$6,525,000	79,496	79,496
Matthew J. Meloy	500%	3,000,000	36,550	36,550
Jennifer R. Kneale	400%	1,600,000	19,493	19,493
Patrick J. McDonie	325%	1,625,000	19,798	19,798
D. Scott Pryor	325%	1,625,000	19,798	19,798
Robert M. Muraro	325%	1,625,000	19,798	19,798

The number of shares subject to each award is determined by dividing the total dollar value allocated to the award by the ten-day average closing price of the shares measured over a period prior to the date of grant.

2019 PSU Plan Design

PSUs vest dependent on the satisfaction of certain service-related conditions and the Company's TSR relative to the TSR of the members of the LTIP Peer Group measured over designated periods. For the 2019 PSUs, the LTIP Peer Group was composed of the following companies as of the date of grant:

2019 LTIP Peer Group	
Buckeye Partners, L.P.	NuStar Energy, L.P.
Crestwood Equity Partners LP	ONEOK, Inc.
DCP Midstream Partners L.P.	Plains GP Holdings, L.P.
Enable Midstream Partners L.P.	Tallgrass Energy, L.P.
EnLink Midstream Partners L.P.	Williams Companies, Inc.
Genesis Energy, L.P.	

The LTIP Peer Group is a subset of the midstream companies included in the 2019 compensation peer group. The LTIP Peer Group is designed to include only those midstream oil & gas companies closest in size to the Company for purpose of the TSR comparison. The Compensation Committee has the ability to modify the LTIP Peer Group in the event a company listed above ceases to be publicly traded or another significant event occurs and a company is determined to no longer be one of the Company's peers. The Compensation Committee made a modification to the 2019 LTIP Peer Group due to an acquisition of one of the peer companies that occurred during 2019.

The overall performance period for the 2019 PSUs begins on January 1, 2019 and ends on December 31, 2021. The TSR performance factor is determined by the Compensation Committee at the end of the overall performance period based on relative TSR performance over the designated weighting periods as follows:

Weighting Period	Percent of Award
Annual relative TSR for Year 1	25%
Annual relative TSR for Year 2	25%
Annual relative TSR for Year 3	25%
Cumulative relative TSR over the three-year performance period	25%
	100%

With respect to each weighting period, the Compensation Committee determines the "guideline performance percentage," which could range from 0% to 250%, based upon the Company's relative TSR performance for the applicable period compared to the LTIP Peer Group as follows:

Relative TSR Attainment	Guideline Performance Percentage* (% of target)
Below 25th percentile	0%
25th percentile	50%
50th Percentile	100%
75th percentile or higher	250%

**** Payout for performance between threshold and target or between target and maximum will be calculated using straight line interpolation.***

Overall TSR performance results will be calculated by averaging the guideline performance percentage for each weighting period. The average performance percentage may then be decreased or increased by the Compensation Committee in order to address factors such as changes to the performance peers, anomalies in trading during the selected trading days or other business performance matters. For these purposes, TSR performance is typically calculated as follows, using a 10-day average stock price at the beginning and following the end of each performance period:

$$\text{TSR} = \frac{\text{Average closing price at end of period + dividends paid over period}}{\text{Average closing price at beginning of period}}$$

Provided the NEO remains continuously employed through the end of 2021, then vesting will occur, as soon as practicable following December 31, 2021, when the Compensation Committee determines applicable performance levels. The NEO will receive PSUs equal to the target number awarded multiplied by the final Compensation Committee determined TSR performance factor. Vested PSUs will be settled by the issuance of Company common stock.

In addition, at the time the PSUs are settled, the NEOs would also receive a cash payment equal to the amount of cash dividends accrued with respect to a share of common stock over the three-year period, times the number of shares earned.

2017 – 2019 PSU Plan Payout

The PSUs granted to our NEOs in 2017 were structured similarly to the 2019 PSUs described above and had an aggregate performance period that ended on December 31, 2019. On January 16, 2020, our Compensation Committee determined that the overall vesting percentage that was earned for the 2017 PSUs was 120% of target grant amounts, and the corresponding shares became vested.

Performance Period	Targa Percentile Rank	Weight	Percent of Target Earned
Year 1 TSR	45th	25%	92%
Year 2 TSR	56th	25%	130%
Year 3 TSR	56th	25%	130%
Cumulative 3 year TSR	56th	25%	130%
Weighted Average			**120%**

Due to the fact that vesting did not occur until our Compensation Committee determined the achievement of applicable performance goals at the beginning of 2020, these awards were still deemed to be "outstanding" as of December 31, 2019 for purposes of the compensation tables that follow this CD&A.

2020 – 2022 PSU Plan Design

In January 2020 we granted PSU awards to our NEOs that contained certain differences from the PSUs granted in prior years. The 2020 PSUs will measure performance over a single three-year performance period. We also made a change to our performance peer group, with TSR measured relative to the companies that make up the Alerian US Midstream Index (AMUS), using the following payout schedule:

Relative TSR Attainment vs. Companies in the Alerian US Midstream Index	Guideline Performance Percentage (% of target)
Below 25th percentile	0%
25th percentile	50%
55th percentile	100%
75th percentile or higher	250%

As shown in the table, we also shifted our target payout to 55th percentile to ensure that a target payout requires performance above the median of our performance peers. Payout for performance between threshold and target or between target and maximum will be calculated using straight line interpolation.

OTHER EXECUTIVE COMPENSATION PRACTICES AND POLICIES

Stock Ownership Guidelines

In May 2017, our Compensation Committee adopted Stock Ownership Guidelines for our independent directors and officers. We believe that our Stock Ownership Guidelines align the interests of our named executive officers and independent directors with the interests of our stockholders. The guidelines below were established with advice from the Compensation Consultant and are believed to follow market standards.

	Ownership Requirement
Chief Executive Officer	5.0 x base salary
Other NEOs	3.0 x base salary
Nonemployee Directors	5.0 x annual cash retainer

The CEO, executive officers and directors have five years from the date first subject to the guidelines to meet the applicable ownership levels. Stock owned directly by an officer or independent director as well as unvested restricted stock units will count for purposes of determining stock ownership levels.

Anti-Hedging and Anti-Margining Policy

All of our officers, employees and directors are subject to our Insider Trading Policy, which, among other things, prohibits officers, employees and directors from engaging in certain short-term or speculative transactions involving our securities. Specifically, the policy provides that officers, employees and directors may not engage in the following transactions: (i) the purchase of our common stock on margin, (ii) short sales of our common stock, or (iii) the purchase or sale of options of any kind, whether puts or calls, or other derivative securities, relating to our common stock.

Recoupment Clawback Policy

In December 2019, our Board adopted an executive compensation clawback policy which provides that performance-based incentive compensation paid to our officers who are subject to Section 16 of the Exchange Act may be recovered by us in the event of a restatement of the Company's financial results or under certain other circumstances, such as an officer’s misconduct that results in an adverse impact on the Company’s financial performance. In connection with such events, the Compensation Committee will have the right to require the reimbursement or forfeiture of any performance-based incentive payments, including payments under the annual incentive plan and performance-based PSUs, paid to the officer to the extent permitted by applicable law. The clawback policy will apply to all performance-based incentive compensation granted following the adoption of the clawback policy.

In addition, the Company will take action to modify the clawback policy to comply with Section 954 of the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010 should the SEC determine and implement final rules. Furthermore, restricted stock, restricted stock unit and performance share unit agreements covering awards made to our named executive officers and other applicable employees include language providing that any compensation, payments or benefits provided under such an award (including profits realized from the sale of earned shares) are subject to clawback to the extent required by applicable law.

Compensation Risk Assessment

The Compensation Committee reviews the relationship between our risk management policies and compensation policies and practices each year and, for 2019, has concluded that we do not have any compensation policies or practices that expose us to excessive or unnecessary risks that are reasonably likely to have a material adverse effect on us. Because our Compensation Committee retains the sole discretion for determining the actual amount paid to executives pursuant to our annual incentive bonus program, our Compensation Committee is able to assess the actual behavior of our executives as it relates to risk-taking in awarding bonus amounts. In addition, the performance objectives applicable to our annual bonus program consist of diverse company-wide and business unit goals, including commercial, operational and financial goals to support our business plan and priorities, which we believe lessens the potential incentive to focus on meeting certain short-term goals at the expense of longer-term risk. Further, our use of long-term equity incentive compensation for 2019 with three-year vesting periods in combination with meaningful ownership requirements serves our executive compensation program's goal of aligning the interests of executives and shareholders, thereby reducing the incentives to unnecessary risk-taking.

Retirement, Health and Welfare, and Other Benefits

Employees are eligible to participate in a section 401(k) tax-qualified, defined contribution plan (the "401(k) Plan"), which helps employees save for retirement through a tax-advantaged combination of employee and company contributions and directly manage their retirement plan assets through a variety of investment options. Under the plan, participants may elect to defer up to 30% of their eligible compensation on a pre-tax basis (or on a post-tax basis via a Roth contribution), subject to certain limitations under the Internal Revenue Code of 1986, as amended (the "Code"). In addition, we make the following contributions to the 401(k) Plan for the benefit of our employees, including our NEOs: (i) 3% of the employee's eligible compensation, and (ii) an amount equal to the employee's contributions to the 401(k) Plan up to 5% of the employee's eligible compensation. In addition, we may also make discretionary contributions to the 401(k) Plan for the benefit of employees depending on our performance. Company contributions to the 401(k) Plan may be subject to certain limitations under the Code for certain employees. We do not maintain a defined benefit pension plan or a nonqualified deferred compensation plan for our NEOs or other employees.

All full-time employees, including our NEOs, may participate in our health and welfare benefit programs, including medical, life insurance, dental coverage and disability insurance. It is the Compensation Committee's policy not to pay for perquisites for any of our NEOs, other than minimal parking subsidies.

Change in Control and Severance Benefits

Our ability to build the exceptional leadership team we have today was due in large part to our having the full complement of compensation tools available to us and the flexibility to use them. This includes the ability to leverage change in control and severance benefits.

The Compensation Committee believes that together, our change in control and severance benefits, which are guided by our governance practices and policies, are well-aligned with those of our peers. More importantly, they foster stability and focus within the senior leadership team by helping to ensure that personal concerns regarding job security do not get in the way of mergers, reorganizations or other transactions that may be in the best interest of shareholders.

Please see "Executive Compensation—Potential Payments Upon Termination or Change in Control" below for further information.

Accounting Considerations

We account for the equity compensation expense for our employees, including our named executive officers, under the rules of Financial Accounting Standards Board ("FASB"), Accounting Standards Codification ("ASC") Topic 718, which requires us to record an expense for each award of long-term equity incentive compensation over the vesting period of the award based on the fair value at the grant date. Accounting rules also require us to record cash compensation as an expense at the time the obligation is accrued.

Tax Considerations

We consider the impact of various tax rules in implementing our compensation program. Section 162(m) of the Code ("Section 162(m)") generally limits the deductibility by a corporation of compensation in excess of $1,000,000 paid to certain executive officers. Due to the fact that our executive officers provide services to both us and to certain non-corporate subsidiaries, we have historically designed incentive awards that are not subject to the deduction limitations of Section 162(m). However, during the 2019 year, new proposed regulations were published with respect to Section 162(m) that will alter the way that compensation is allocated between services to us and our subsidiaries, and certain compensation granted to our covered executive officers may become subject to the deductibility restrictions of 162(m). Our Compensation Committee believes that its primary responsibility is to provide a compensation program that is consistent with its compensation philosophy and supports the achievement of its compensation objectives. Therefore the Compensation Committee has retained the authority to grant appropriate compensation items or awards to our service providers notwithstanding an adverse tax or accounting treatment for that compensation.

Compensation Committee Report

In fulfilling its oversight responsibilities, the board of directors of our general partner has reviewed and discussed with management the Compensation Discussion and Analysis contained in our Annual Report on Form 10-K for the year ended December 31, 2019. Based on these reviews and discussions, the board of directors of our general partner recommended that the Compensation Discussion and Analysis be included in our Annual Report on Form 10-K for the year ended December 31, 2019 for filing with the SEC.

The information contained in this report shall not be deemed to be “soliciting material” or to be “filed” with the SEC, nor shall such information be incorporated by reference into any future filings with the SEC, or subject to the liabilities of Section 18 of the Exchange Act, except to the extent that we specifically incorporate it by reference into a document filed under the Securities Act of 1933, as amended (the “Securities Act”), or the Exchange Act.

The board of directors of our general partner:

Joe Bob Perkins	James W. Whalen	Charles R. Crisp
Waters S. Davis, IV	Robert B. Evans	Laura C. Fulton
Ershel C. Redd Jr.	Chris Tong	Rene R. Joyce
Beth A. Bowman		

EXECUTIVE COMPENSATION

Summary Compensation Table for 2019

The following Summary Compensation Table sets forth the compensation of our named executive officers for 2019, 2018 and 2017. Additional details regarding the applicable elements of compensation in the Summary Compensation Table are provided in the footnotes following the table.

Name and Principal Position	Year	Salary	Bonus (1)	Stock Awards ($) (2) (3)	All Other Compensation (4)	Total
Joe Bob Perkins	2019	$ 891,667	—	$ 11,545,172	$ 23,710	$12,460,549
Chief Executive Officer	2018	833,333	—	12,624,959	23,310	13,481,602
	2017	745,833	—	4,552,878	23,184	5,321,895
Matthew J. Meloy	2019	$ 587,500	$ 1,920,000	$ 3,921,450	$ 23,710	$ 6,452,660
President	2018	516,667	1,115,625	3,914,716	23,037	5,570,045
	2017	472,500	418,800	4,901,220	22,814	5,815,334
Jennifer R. Kneale	2019	$ 391,667	$ 640,000	$ 2,091,404	$ 23,274	$ 3,146,345
Chief Financial Officer	2018	332,500	446,250	1,166,427	22,535	1,967,712
Patrick J. McDonie	2019	$ 495,833	$ 800,000	$ 2,124,127	$ 23,492	$ 3,443,452
President – Gathering and Processing	2018	466,667	807,500	1,803,674	22,928	3,100,769
	2017	422,633	221,000	3,977,300	22,685	4,643,618
D. Scott Pryor	2019	$ 495,833	$ 800,000	$ 2,124,127	$ 23,492	$ 3,443,452
President - Logistics and Marketing	2018	466,667	807,500	1,803,674	22,928	3,100,769
	2017	419,167	221,000	3,969,916	22,630	4,632,713
Robert M. Muraro	2019	$ 491,667	$ 800,000	$ 2,124,127	$ 23,492	$ 3,439,286
Chief Commercial Officer	2018	433,333	765,000	1,666,299	22,764	2,887,396
	2017	331,667	168,000	6,037,998	22,234	6,559,899

(1) For 2019, amounts reported in the "Bonus" column represents the portion of the bonus awarded pursuant to our 2019 Bonus Plan that was paid to the named executive officers in cash. The Compensation Committee approved settlement of the 2019 bonuses in a combination of cash and restricted stock unit awards. Specifically, the Compensation Committee determined that 100% of our Chief Executive Officer's total bonus would be settled in the form of restricted stock unit awards, resulting in the Chief Executive Officer receiving restricted stock unit awards with a grant date value corresponding to approximately 160% of his target bonus amounts under the 2019 Bonus Plan. The Compensation Committee also determined that each other named executive officer's total bonus amount would be settled in cash. The restricted stock unit awards granted to the Chief Executive Officer will vest in full one year after the date of award, subject to continued employment of the Chief Executive Officer through that date. These awards were granted on January 16, 2020 and will therefore be reported as equity award compensation in the Summary Compensation Table for 2020 in accordance with SEC rules. Please see "Compensation Discussion and Analysis—Components of Executive Compensation Program for Fiscal 2019—Annual Incentive Bonus." As discussed above, payments pursuant to our Bonus Plan are discretionary and not based on specific objective performance measures.

(2) Amounts reported in the "Stock Awards" column for 2019 represent the aggregate grant date fair value of restricted stock unit and performance share unit awards granted under our Stock Incentive Plan in 2019 (including restricted stock unit awards granted on January 17, 2019 in connection with 100% of the bonus for the Chief Executive Officer under the 2018 Bonus Plan that we granted in the form of restricted stock units) computed in accordance with FASB ASC Topic 718, disregarding the estimate of forfeitures. Assumptions used in the calculation of these amounts are included in Note 24—Compensation Plans to our "Consolidated Financial Statements" included in our Annual Report on Form 10-K for fiscal year 2019. Detailed information about the value attributable to specific awards is reported in the table under "—Grants of Plan-Based Awards for 2019" below. The grant date fair value of each restricted stock unit subject to the restricted stock unit awards granted on January 17, 2019, assuming vesting will occur, is $42.83. The grant date fair value of each performance share unit subject to the performance share unit awards granted on January 17, 2019, assuming vesting will occur, is $64.46, which is the per unit fair value determined using a Monte Carlo Simulation valuation methodology in accordance with FASB ASC Topic 718. Assuming, instead, a payout percentage for these performance unit awards of 250%, which is the maximum payout percentage under the awards, the aggregate grant date fair value of the equity-settled performance unit awards granted on January 17, 2019 for each named executive officer is as follows: Mr. Perkins – $12,810,780; Mr. Meloy – $5,890,033; Ms. Kneale – $3,141,297; Mr. McDonie – $3,190,448; Mr. Pryor – $3,190,448; and Mr. Muraro – $3,190,448. For 2018, the Compensation Committee provided that bonuses to our named executive officers under the 2018 Bonus Plan would be (i) 100% restricted stock unit awards equal to the Chief Executive Officer's total bonus amount and (ii) cash equal to each of the other named executive officer's total bonus amount. The restricted stock unit award will vest in full three years after the date of award, subject to continued employment of the Chief Executive Officer through that date. Because this award was granted on January 17, 2019, it is

reported as compensation in the Summary Compensation Table for 2019 in accordance with SEC rules. For 2017, the Compensation Committee provided that bonuses to our named executive officers under the 2017 Bonus Plan would be (i) 100% restricted stock unit awards equal to the Chief Executive Officer's total bonus amount and (ii) a combination of cash equal to 50% of each of the other named executive officer's total bonus amount and restricted stock unit awards equal to each other named executive officer's total bonus amount. These restricted stock unit awards will vest in full three years after the date of award, subject to continued employment of the officers through that date. Because these awards were granted on January 17, 2018, they are reported as compensation in the Summary Compensation Table for 2018 in accordance with SEC rules.

(3) On January 12, 2018, the Compensation Committee awarded a special performance/retention award to Mr. Perkins. The special performance/retention award consisting of 80,000 units was granted in the form of restricted stock units that vested 50% on December 31, 2018 and 50% on December 31, 2019.

(4) For 2019, "All Other Compensation" includes (i) the aggregate value of all employer-provided contributions to our 401(k) plan and (ii) the dollar value of life insurance premiums paid by the Company with respect to life insurance for the benefit of each named executive officer.

Name	401(k) and Profit Sharing Plan	Dollar Value of Life Insurance Premiums	Total
Joe Bob Perkins	$ 22,400	$ 1,310	$ 23,710
Matthew J. Meloy	22,400	1,310	23,710
Jennifer R. Kneale	22,400	874	23,274
Patrick J. McDonie	22,400	1,092	23,492
D. Scott Pryor	22,400	1,092	23,492
Robert M. Muraro	22,400	1,092	23,492

Grants of Plan-Based Awards for 2019

The following table and the footnotes thereto provide information regarding grants of plan-based equity awards made to the named executive officers during 2019:

		Estimated Future Payouts Under Performance Share Unit Awards				
Name	Grant Date	Threshold (#)	Target (#)	Maximum (#)	Equity Awards: Number of Units	Grant Date Fair Value of Equity Awards (3)
Mr. Perkins	01/17/19 (1)	39,748	79,496	198,740	79,496	$ 8,529,126
	01/17/19 (2)				70,419	3,016,046
Mr. Meloy	01/17/19 (1)	18,275	36,550	91,375	36,550	3,921,450
Ms. Kneale	01/17/19 (1)	9,747	19,493	48,733	19,493	2,091,404
Mr. McDonie	01/17/19 (1)	9,899	19,798	49,495	19,798	2,142,127
Mr. Pryor	01/17/19 (1)	9,899	19,798	49,495	19,798	2,124,127
Mr. Muraro	01/17/19 (1)	9,899	19,798	49,495	19,798	2,124,127

(1) The grants on January 17, 2019 are the annual long-term equity incentive awards for 2019 granted to our named executive officers in the form of restricted stock unit and performance share unit awards granted under our Stock Incentive Plan. For a detailed description of how performance achievements will be determined for performance share units, see "Compensation Discussion and Analysis – 2019 Components of Executive Compensation Program In Detail – 2019 PSU Plan Design."

(2) The grant on January 17, 2019 is a restricted stock unit award granted to Mr. Perkins in lieu of 100% of the cash payments under the 2018 Bonus Plan. The restricted stock unit awards that will be granted to Mr. Perkins with respect to the 2019 Bonus Plan were not granted until January 2020, therefore are not reflected within this table.

(3) The value within the "Grant Date Fair Value of Equity Awards" column was determined by multiplying the shares awarded by the grant date fair value per share computed in accordance with FASB ASC Topic 718: $42.83 for the January 17, 2019 restricted stock unit awards; and $64.46 for the January 17, 2019 performance share units.

Narrative Disclosure to Summary Compensation Table and Grants of Plan Based Awards Table

A discussion of 2019 salaries, bonuses, incentive plans and awards is set forth in "Compensation Discussion and Analysis," including a discussion of the material terms and conditions of the 2019 restricted stock unit and performance share unit awards under our Stock Incentive Plan. Further discussion regarding restricted stock units granted in January 2019 in lieu of a cash payment under our 2018 Bonus Plan are described in our proxy statement for our 2019 annual meeting of stockholders, filed with the Securities and Exchange Commission on March 29, 2019.

Outstanding Equity Awards at 2019 Fiscal Year-End

The following table and the footnotes related thereto provide information regarding equity-based awards outstanding as of December 31, 2019 for each of our named executive officers. None of our named executive officers held any outstanding stock option awards as of December 31, 2019.

	Stock Awards			
Name	**Number of Shares That Have Not Vested (1)**	**Market Value of Shares That Have Not Vested (2)**	**Performance Share Units: Number of Unearned Units That Have Not Vested (3)**	**Performance Share Units: Market or Payout Value of Unearned Units That Have Not Vested (4)**
Joe Bob Perkins	307,042	$ 12,536,525	139,891	$ 5,711,750
Matthew J. Meloy	148,136	6,048,393	69,814	2,850,506
Jennifer R. Kneale	77,572	3,167,265	30,154	1,231,188
Patrick J. McDonie	99,029	4,043,354	35,107	1,433,422
D. Scott Pryor	98,897	4,037,965	35,107	1,433,422
Robert M. Muraro	136,956	5,591,913	34,385	1,403,942

(1) Represents the following shares of restricted stock units (and earned performance units) under our Stock Incentive Plan held by our named executive officers:

	Joe Bob Perkins	Matthew J. Meloy	Jennifer R. Kneale	Patrick J. McDonie	D. Scott Pryor	Robert M. Muraro
January 6, 2016 Award (a)	—	—	10,000	—	—	—
January 20, 2017 Award (b)	25,742	10,190	—	6,929	6,929	7,500
January 20, 2017 Award (c)	—	50,000	30,000	45,000	45,000	60,000
January 20, 2017 Award (d)	30,891	12,228	—	8,315	8,315	9,000
February 28, 2017 Award (e)	7,676	4,383	720	2,610	2,478	974
July 23, 2017 Award (f)	—	—	—	—	—	25,000
August 1, 2017 Award (g)	—	—	7,080	—	—	—
January 17, 2018 Award (h)	46,987	26,383	7,915	11,935	11,935	11,307
January 17, 2018 Award (i)	45,831	8,402	2,364	4,442	4,442	3,377
January 17, 2019 Award (j)	79,496	36,550	19,493	19,798	19,798	19,798
January 17, 2019 Award (k)	70,419	—	—	—	—	—
Total	307,042	148,136	77,572	99,029	98,897	136,956

(a) The restricted stock units awarded January 6, 2016 vest: (i) 50% on January 6, 2020 and 50% on January 6, 2021, contingent upon continuous employment through the end of the vesting period. The underlying shares of stock are not issued until vesting at the end of the vesting period.

(b) The restricted stock units awarded January 20, 2017 are subject to the following vesting schedule: 100% of the restricted stock units vest on January 20, 2020, contingent upon continuous employment or the satisfaction of certain other service-related conditions upon the executive's retirement, in either case, through the end of the vesting period. The underlying shares of stock are not issued until vesting at the end of the vesting period.

(c) The restricted stock units awarded January 20, 2017 as a retention grant vest (i) 30% on January 20, 2021, (ii) 30% on January 20, 2022 and (iii) 40% on January 20, 2023, contingent upon continuous employment through the end of the performance period. The underlying shares of stock are not issued until vesting at the end of the vesting period.

(d) The awards in this row originally related to performance share units granted in 2017, but for which the performance period ended on December 31, 2019. Because the awards were no longer subject to performance conditions, but would not be deemed "vested" until the Compensation Committee determined performance levels in early 2020, they are still deemed to be outstanding for purposes of this table, subject only to time-based vesting requirements. The target awards were multiplied by 120%, the actual adjustment factor applied to the awards upon determination of performance levels in 2020.

(e) The restricted stock units awarded February 28, 2017 in partial settlement of awards under the 2016 Bonus Plan are subject to the following vesting schedule: 100% of the restricted stock units vest February 28, 2020, contingent upon continuous employment or the satisfaction of certain other service-related conditions upon the executive's retirement, in either case, through the end of the vesting period. The underlying shares of stock are not issued until vesting at the end of the vesting period.

(f) The restricted stock units awarded July 23, 2017 as a retention grant vest on July 23, 2020, contingent upon continuous employment through the end of the performance period. The underlying shares of stock are not issued until vesting at the end of the vesting period.

(g) The restricted stock units awarded August 1, 2017 are subject to the following vesting schedule: 100% of the restricted stock units vest on August 1, 2020, contingent upon continuous employment or the satisfaction of certain other service-related conditions upon the executive's retirement, in either case, through the end of the vesting period. The underlying shares of stock are not issued until vesting at the end of the vesting period.

(h) The restricted stock units awarded January 17, 2018 are subject to the following vesting schedule: 100% of the restricted stock units vest on January 17, 2021, contingent upon continuous employment or the satisfaction of certain other service-related conditions upon the executive's retirement, in either case, through the end of the vesting period. The underlying shares of stock are not issued until vesting at the end of the vesting period.

(i) The restricted stock units awarded January 17, 2018 in settlement (with respect to our Chief Executive Officer) and in partial settlement (with respect to the other named executive officers) of awards under the 2017 Bonus Plan are subject to the following vesting schedule: 100% of the restricted stock units vest January 17, 2021, contingent upon continuous employment or the satisfaction of certain other service-related conditions upon the executive's retirement, in either case, through the end of the vesting period. The underlying shares of stock are not issued until vesting at the end of the vesting period.

(j) The restricted stock units awarded January 17, 2019 are subject to the following vesting schedule: 100% of the restricted stock units vest on January 17, 2022, contingent upon continuous employment or the satisfaction of certain other service-related conditions upon the executive's retirement, in either case, through the end of the vesting period. The underlying shares of stock are not issued until vesting at the end of the vesting period.

(k) The restricted stock units awarded January 17, 2019 in settlement of an award under the 2018 Bonus Plan are subject to the following vesting schedule: 100% of the restricted stock units vest January 17, 2022, contingent upon continuous employment or the satisfaction of certain other service-related conditions upon the executive's retirement, in either case, through the end of the vesting period. The underlying shares of stock are not issued until vesting at the end of the vesting period.

The treatment of the outstanding restricted stock unit awards upon certain terminations of employment (including retirement) or the occurrence of a change in control is described below under "—Potential Payments Upon Termination or Change in Control."

(2) The dollar amounts shown are determined by multiplying the number of shares of restricted stock units reported in the table by the closing price of a share of our common stock on December 31, 2019 ($40.83), which was the last trading day of fiscal 2019. The amounts do not include any related dividends accrued with respect to the awards.

(3) Represents the following performance share units linked to the performance of the Company's common stock held by our named executive officers:

	January 17, 2018 Award		January 17, 2019 Award	
	Awards Granted	(a) Adjusted for Performance Factor (TSR)	Awards Granted	(b) Adjusted for Performance Factor (TSR)
Joe Bob Perkins	46,987	54,035	79,496	85,856
Matthew J. Meloy	26,383	30,340	36,550	39,474
Jennifer R. Kneale	7,915	9,102	19,493	21,052
Patrick J. McDonie	11,935	13,725	19,798	21,382
D. Scott Pryor	11,935	13,725	19,798	21,382
Robert R. Muraro	11,307	13,003	19,798	21,382

(a) Reflects the target number of performance share units granted to the named executive officers on January 17, 2018 multiplied by a performance percentage of 115%, which in accordance with SEC rules is the next higher performance level under the award that exceeds 2019 performance. Vesting of these awards is contingent upon continuous employment or the satisfaction of certain other service-related conditions upon the executive's retirement, in either case, through the end of the performance period, which ends December 31, 2020, and the Company's performance over the applicable performance period measured against a peer group of companies. The underlying shares of stock are not issued until vesting levels have been determined by the Compensation Committee.

(b) Reflects the target number of performance share units granted to the named executive officers on January 17, 2019 multiplied by a performance percentage of 108%, which in accordance with SEC rules is the next higher performance level under the award that exceeds 2019 performance. Vesting of these awards is contingent upon continuous employment or the satisfaction of certain other service-related conditions upon the executive's retirement, in either case, through the end of the performance period, which ends December 31, 2021, and the Company's performance over the applicable performance period measured against a peer group of companies. The underlying shares of stock are not issued until vesting levels have been determined by the Compensation Committee.

The treatment of the outstanding performance share unit awards upon certain terminations of employment (including retirement) or the occurrence of a change in control is described below under "—Potential Payments Upon Termination or Change in Control."

(4) The dollar amounts shown are determined by multiplying the number of shares of performance share units reported in the table by the closing price of a share of our common stock on December 31, 2019 ($40.83), which was the last trading day of fiscal 2019. The amounts do not include any related dividends accrued with respect to the awards.

Option Exercises and Stock Vested in 2019

The following table provides the amount realized during 2019 by each named executive officer upon the vesting of restricted stock and restricted stock units. None of our named executive officers exercised any option awards during the 2019 year and, currently, there are no options outstanding under any of our plans.

	Stock Awards	
Name	Number of Shares Acquired on Vesting (#)	Value Realized on Vesting (1) ($)
Joe Bob Perkins	170,804	7,230,851
Matthew J. Meloy	47,799	2,038,507
Jennifer R. Kneale	7,905	307,220
Patrick J. McDonie	36,174	1,542,182
D. Scott Pryor	39,068	1,669,658
Robert M. Muraro	10,779	417,761

(1) Computed with respect to the restricted stock awards granted under our Stock Incentive Plan by multiplying the number of shares of stock vesting by the closing price of a share of common stock on the January 19, 2019 vesting date ($43.50), the February 28, 2019 vesting date ($40.24), the August 1, 2019 vesting date ($37.37) and the December 31, 2019 vesting date ($40.83) and does not include associated dividends accrued during the vesting period.

Pension Benefits

Other than our 401(k) Plan, we do not have any plan that provides for payments or other benefits at, following, or in connection with, retirement.

Non-Qualified Deferred Compensation

We do not have any plan that provides for the deferral of compensation on a basis that is not tax qualified.

Potential Payments Upon Termination or Change in Control

Aggregate Payments

The table below reflects the aggregate amount of payments and benefits that we believe our named executive officers would have received under the Change in Control Program (described below) and Stock Incentive Plan upon certain specified termination of employment and/or a change in control events, in each case, had such event occurred on December 31, 2019. Details regarding individual plans and arrangements follow the table. The amounts below constitute estimates of the amounts that would be paid to our named executive officers upon each designated event, and do not include any amounts accrued through fiscal 2019 year-end that would be paid in the normal course of continued employment, such as accrued but unpaid salary and benefits generally available to all salaried employees. The actual amounts to be paid are dependent on various factors, which may or may not exist at the time a named executive officer is actually terminated and/or a change in control actually occurs. Therefore, such amounts and disclosures should be considered “forward-looking statements.”

Name	Change in Control (No Termination)	Qualifying Termination Following Change in Control	Termination by us without Cause	Termination for Death or Disability
Joe Bob Perkins	$ 20,280,865	$ 29,234,591	—	$ 20,280,865
Matthew J. Meloy	10,423,248	15,881,403	—	10,423,248
Jennifer R. Kneale	5,214,049	7,614,049	—	5,214,049
Patrick J. McDonie	6,497,469	9,560,031	—	6,497,469
D. Scott Pryor	6,490,759	9,548,914	—	6,490,759
Robert R. Muraro	8,395,350	11,453,505	—	8,395,350

Executive Officer Change in Control Severance Program

We adopted the Change in Control Program on and effective as of January 12, 2012. Each of our named executive officers was an eligible participant in the Change in Control Program during the 2019 calendar year.

The Change in Control Program is administered by our Senior Vice President—Human Resources. The Change in Control Program provides that if, in connection with or within 18 months after a "Change in Control," a participant suffers a "Qualifying Termination," then the individual will receive a severance payment, paid in a single lump sum cash payment within 60 days following the date of termination, equal to three times (i) the participant's annual salary as of the date of the Change in Control or the date of termination, whichever is greater, and (ii) the amount of the participant's annual salary multiplied by the participant's most recent "target" bonus percentage specified by the Compensation Committee prior to the Change in Control. In addition, the participant (and his eligible dependents, as applicable) will receive the continuation of their medical and dental benefits until the earlier to occur of (a) three years from the date of termination, or (b) the date the participant becomes eligible for coverage under another employer's plan.

For purposes of the Change in Control Program, the following terms will generally have the meanings set forth below:

Cause means discharge of the participant by us on the following grounds: (i) the participant's gross negligence or willful misconduct in the performance of his duties, (ii) the participant's conviction of a felony or other crime involving moral turpitude, (iii) the participant's willful refusal, after 15 days' written notice, to perform his material lawful duties or responsibilities, (iv) the participant's willful and material breach of any corporate policy or code of conduct, or (v) the participant's willfully engaging in conduct that is known or should be known to be materially injurious to us or our subsidiaries.

Change in Control means any of the following events: (i) any person (other than the Partnership) becomes the beneficial owner of more than 20% of the voting interest in us or in the General Partner, (ii) any sale, lease, exchange or other transfer (in one transaction or a series of related transactions) of all or substantially all of the assets of the Company or the General Partner (other than to the Partnership or its affiliates), (iii) a transaction resulting in a person other than Targa Resources GP LLC or an affiliate being the General Partner of the Partnership, (iv) the consummation of any merger, consolidation or reorganization involving us or the General Partner in which less than 51% of the total voting power of outstanding stock of the surviving or resulting entity is beneficially owned by the stockholders of the Company or the General Partner, immediately prior to the consummation of the transaction, or (v) a majority of the members of the Board of Directors or the board of directors of the General Partner is replaced during any 12-month period by directors whose appointment or election is not endorsed by a majority of the members of the applicable Board of Directors before the date of the appointment or election.

Good Reason means: (i) a material reduction in the participant's authority, duties or responsibilities, (ii) a material reduction in the participant's base compensation, or (iii) a material change in the geographical location at which the participant must perform services. The individual must provide notice to us of the alleged Good Reason event within 90 days of its occurrence and we have the opportunity to remedy the alleged Good Reason event within 30 days from receipt of the notice of such allegation.

Qualifying Termination means (i) an involuntary termination of the individual's employment by us without Cause or (ii) a voluntary resignation of the individual's employment for Good Reason.

All payments due under the Change in Control Program will be conditioned on the execution and non-revocation of a release for our benefit and the benefit of our related entities and agents. The Change in Control Program will supersede any other severance program for eligible participants in the event of a Change in Control, but will not affect accelerated vesting of any equity awards under the terms of the plans governing such awards.

If amounts payable to a named executive officer under the Change in Control Program, together with any other amounts that are payable by us as a result of a Change in Control (collectively, the "Payments"), exceed the amount allowed under section 280G of the Code for such individual, thereby subjecting the individual to an excise tax under section 4999 of the Code, then, depending on which method produces the largest net after-tax benefit for the recipient, the Payments shall either be: (i) reduced to the level at which no excise tax applies or (ii) paid in full, which would subject the individual to the excise tax.

The following table reflects payments that would have been made to each of the named executive officers under the Change in Control Program in the event there was a Change in Control and the officer incurred a Qualifying Termination, in each case as of December 31, 2019.

Name	Qualifying Termination Following Change in Control (1)
Joe Bob Perkins	$8,953,726
Matthew J. Meloy	5,458,155
Jennifer R. Kneale	2,400,000
Patrick J. McDonie	3,062,562
D. Scott Pryor	3,058,155
Robert R. Muraro	3,058,155

(1) Includes 3 years' worth of continued participation in our medical and dental plans, calculated based on the monthly employer-paid portion of the premiums for our medical and dental plans as of December 31, 2019 for each named executive officer and the officer's eligible dependents in the following amounts: (a) Mr. Perkins – $43,726, (b) Mr. Meloy – $58,155, (c) Ms. Kneale– 0, (d) Mr. McDonie – $62,562, (e) Mr. Pryor – $58,155, and (f) Mr. Muraro—$58,155.

Stock Incentive Plan

Our named executive officers held outstanding restricted stock units under our form of restricted stock unit agreement (the "Stock Agreement"), and performance share units under our form of performance share unit agreement (the "Performance Agreement") and the Stock Incentive Plan as of December 31, 2019. If a "Change in Control" occurs and the named executive officer has (i) remained continuously employed by us from the date of grant to the date upon which such Change in Control occurs or (ii) retired following the date of grant and either performed consulting services for us or refrained from working for one of our competitors or in a similar role for another company (however, directorships at non-competitors are permitted), through the date of the Change in Control, then, in either case, (a) the restricted stock units granted to the officer under the Stock Agreement, and related dividends then credited to the officer, will fully vest on the date upon which such Change in Control occurs, and (b) the performance share units granted to the officer under the Performance Agreement and related dividends credited to the officer will vest based on a performance factor as of the date of the Change in Control determined by the Compensation Committee. The 2019 performance share units have four separate performance periods: (1) the 2019 calendar year, (2) the 2020 calendar year, (3) the 2021 calendar year, and (4) the entirety of the performance period between January 1, 2019 and December 31, 2021. Upon a Change in Control transaction, the Compensation Committee will take into account the average of the performance level achieved for each of the four performance periods, using the actual performance level achieved with respect to any completed period, and a deemed performance percentage of 100% for any performance period that has not been completed. The average percentage may then be decreased or increased by the Compensation Committee in its discretion. The Performance Agreements governing awards granted in 2017 and 2018 vest under the same performance schedules as described above with respect to the 2019 awards, with appropriate adjustments for the years at issue.

Restricted stock units and performance share units granted to a named executive officer under the Stock Agreement and Performance Agreement, and related dividends then credited to the officer, will also fully vest if the named executive officer's employment is terminated by reason of death or a "Disability" (as defined below). If a named executive officer's employment with us is terminated for any reason other than death or Disability, then the officer's unvested restricted stock units and performance share units are forfeited to us for no consideration, except that (other than with respect to retention grants for Mr. Perkins, Mr. Meloy, Ms. Kneale, Mr. McDonie, Mr. Pryor and Mr. Muraro), if a named executive officer retires or otherwise has a voluntary resignation, the officer's awards will continue to vest on the original vesting schedule if, from the date of the officer's retirement or termination through the applicable vesting date, the named executive officer has either performed consulting services for us or refrained from working for one of our competitors or in a similar role for another company (however, directorships at non-competitors are permitted).

The following terms generally have the following meanings for purposes of the Stock Incentive Plan, Stock Agreements and Performance Agreements:

Affiliate means an entity or organization which, directly or indirectly, controls, is controlled by, or is under common control with, us.

Change in Control means the occurrence of one of the following events: (i) any person or group acquires or gains ownership or control (including, without limitation, the power to vote), by way of merger, consolidation, recapitalization, reorganization or otherwise, of more than 50% of the outstanding shares of our voting stock or more than 50% of the combined voting power of the equity interests in the Partnership or the General Partner, (ii) any person, including a group as contemplated by section 13(d)(3) of the Exchange Act, acquires in any twelve-month period (in one transaction or a series of related transactions) ownership, directly or indirectly, of 30% or more of the outstanding shares of our voting stock or of the combined voting power of the equity interests in the Partnership or the General Partner, (iii) the completion of a liquidation or dissolution of us or the approval by the limited partners of the Partnership, in one or a series of transactions, of a plan of complete liquidation of the Partnership, (iv) the sale or other disposition by us of all or substantially all of our assets in one or more transactions to any person other than an Affiliate, (v) the sale or disposition by either the Partnership or the General Partner of all or substantially all of its assets in one or more transactions to any person other than to an Affiliate, (vi) a transaction resulting in a person other than Targa Resources GP LLC or an Affiliate being the General Partner of the Partnership, or (vii) as a result of or in connection with a contested election of directors, the persons who were our directors before such election shall cease to constitute a majority of our Board of Directors.

Disability means a disability that entitles the named executive officer to disability benefits under our long-term disability plan.

The following table reflects amounts that would have been received by each of the named executive officers under the Stock Incentive Plan and related Stock Agreements and Performance Agreements in the event there was a Change in Control or their employment was terminated due to death or Disability, each as of December 31, 2019. The amounts reported below assume that the price per share of our common stock was $40.83, which was the closing price per share of our common stock on December 31, 2019 (the last trading day of fiscal 2019). No amounts are reported assuming retirement as of December 31, 2019, since additional conditions must be met following a named executive officer's retirement in order for any restricted stock awards or restricted stock units to become vested.

Name	Change in Control	Termination for Death or Disability
Joe Bob Perkins	$ 20,280,865(1)	$20,280,865(1)
Matthew J. Meloy	10,423,248(2)	10,423,248(2)
Jennifer R. Kneale	5,214,049(3)	5,214,049(3)
Patrick J. McDonie	6,497,469(4)	6,497,469(4)
D. Scott Pryor	6,490,759(5)	6,490,759(5)
Robert R. Muraro	8,395,350(6)	8,395,350(6)

(1) Of the amount reported under each of the "Change in Control" column and the "Termination for Death or Disability" column:
(a) $1,051,046, and $281,103, respectively, relate to restricted stock units and related dividend rights granted on January 20, 2017, which are scheduled to vest on January 20, 2020;
(b) $1,261,280, and $337,330, respectively, relate to performance share units and related dividend rights granted on January 17, 2017, where the performance period ended on December 31, 2019; however, the awards deemed "earned" were still deemed to be outstanding as of December 31, 2019, therefore a Change in Control or termination due to death or Disability could accelerate the time at which the awards could be settled with the executive;
(c) $313,411, and $76,837, respectively, relate to restricted stock units and related dividend rights granted on February 28, 2017, in partial settlement of an award under the 2016 Bonus Plan, which are scheduled to vest on February 28, 2020;
(d) $1,918,479, and $342,065, respectively, relate to restricted stock units and related dividend rights granted on January 17, 2018, which are scheduled to vest January 17, 2021;
(e) $1,871,280, and $0, respectively, relate to restricted stock units and related dividend rights granted on January 17, 2018, in settlement of an award under the 2017 Bonus Plan, which are scheduled to vest January 17, 2021;
(f) $2,206,249, and $393,375, respectively, relate to performance share units and related dividend rights granted on January 17, 2018, which have an aggregate performance period that will end on December 31, 2020;
(g) $3,245,822, and $289,365, respectively, relate to restricted stock units and related dividend rights granted on January 17, 2019, which are scheduled to vest January 17, 2022;
(h) $2,875,208, and $0, respectively, relate to the restricted stock units and related dividend rights granted on January 17, 2019, in settlement of an award under the 2018 Bonus Plan, which are scheduled to vest January 17, 2022; and
(i) $3,505,500, and $312,515, respectively, relate to performance share units and related dividend rights granted on January 17, 2019, which have an aggregate performance period that will end on December 31, 2021.

(2) Of the amount reported under each of the "Change in Control" column and the "Termination for Death or Disability" column:
(a) $416,058, and $111,275, respectively, relate to restricted stock units and related dividend rights granted on January 20, 2017, which are scheduled to vest on January 20, 2020;
(b) $499,269, and $133,530, respectively, relate to performance share units and related dividend rights granted on January 17, 2017, where the performance period ended on December 31, 2019; however, the awards deemed "earned" were still deemed to be outstanding as of 12/31/2019, therefore a Change in Control or termination due to death or Disability could accelerate the time at which the awards could be settled with the executive;
(c) $2,041,500, and $546,000, respectively, relate to restricted stock units awarded January 20, 2017 as a retention grant which vest (i) 30% on January 20, 2021, (ii) 30% on January 20, 2022 and (iii) 40% on January 20, 2023, contingent upon continuous employment;

(d) $178,958, and $43,874, respectively, relate to restricted stock units and related dividend rights granted on February 28, 2017, in partial settlement of an award under the 2016 Bonus Plan, which are scheduled to vest on February 28, 2020;
(e) $1,077,218, and $192,068 respectively, relate to restricted stock units and related dividend rights granted on January 17, 2018, which are scheduled to vest January 17, 2021;
(f) $343,054, and $0, respectively, relate to restricted stock units and related dividend rights granted on January 17, 2018, in partial settlement of an award under the 2017 Bonus Plan, which are scheduled to vest January 17, 2021;
(g) $1,238,782, and $220,875, respectively, relate to performance share units and related dividend rights granted on January 17, 2018, which have an aggregate performance period that will end on December 31, 2020;
(h) $1,492,337, and $133,042, respectively, relate to restricted stock units and related dividend rights granted on January 17, 2019, which are scheduled to vest January 17, 2022; and
(i) $1,611,723, and $143,685, respectively, relate to performance share units and related dividend rights granted on January 17, 2019, which have an aggregate performance period that will end on December 31, 2021.

(3) Of the amount reported under each of the "Change in Control" column and the "Termination for Death or Disability" column:
(a) $408,300, and $145,600, respectively, relate to restricted stock units and related dividend rights granted on January 6, 2016, which are scheduled to vest (i) 50% on January 6, 2020 and (ii) 50% on January 6, 2021;
(b) $1,224,900, and $327,600, respectively, relate to restricted stock units awarded January 20, 2017 as a retention grant which vest (i) 30% on January 20, 2021, (ii) 30% on January 20, 2022 and (iii) 40% on January 20, 2023, contingent upon continuous employment;
(c) $29,398, and $7,207, respectively, relate to restricted stock units and related dividend rights granted on February 28, 2017, in partial settlement of an award under the 2016 Bonus Plan, which are scheduled to vest on February 28, 2020;
(d) $289,076, and $63,720, respectively, relate to restricted stock units and related dividend rights granted on August 1, 2017, which are scheduled to vest August 1, 2020;
(e) $323,169, and $57,621, respectively, relate to restricted stock units and related dividend rights granted on January 17, 2018, which are scheduled to vest January 17, 2021;
(f) $96,522, and $0, respectively, relate to restricted stock units and related dividend rights granted on January 17, 2018, in partial settlement of an award under the 2017 Bonus Plan which are scheduled to vest January 17, 2021;
(g) $371,635, and $66,265, respectively, relate to performance share units and related dividend rights granted on January 17, 2018, which have an aggregate performance period that will end on December 31, 2020;
(h) $795,899, and $70,955, respectively, relate to restricted stock units and related dividend rights granted on January 17, 2019, which are scheduled to vest January 17, 2022; and
(i) $859,553, and $76,629, respectively, relate to performance share units and related dividend rights granted on January 17, 2019, December 31, 2021.

(4) Of the amount reported under each of the "Change in Control" column and the "Termination for Death or Disability" column:
(a) $282,911, and $75,665, respectively, relate to restricted stock units and related dividend rights granted on January 20, 2017, which are scheduled to vest on January 20, 2020;
(b) $339,501, and $90,798, respectively, relate to performance share units and related dividend rights granted on January 17, 2017, where the performance period ended on December 31, 2019; however, the awards deemed "earned" were still deemed to be outstanding as of 12/31/2019, therefore a Change in Control or termination due to death or Disability could accelerate the time at which the awards could be settled with the executive;
(c) $1,837,350, and $491,400, respectively, relate to restricted stock units awarded January 20, 2017 as a retention grant which vest (i) 30% on January 20, 2021, (ii) 30% on January 20, 2022 and (iii) 40% on January 20, 2023, contingent upon continuous employment;
(d) $106,566, and $26,126, respectively, relate to restricted stock units and related dividend rights granted on February 28, 2017, in partial settlement of an award under the 2016 Bonus Plan, which are scheduled to vest on February 28, 2020;
(e) $487,306, and $86,887, respectively, relate to restricted stock units and related dividend rights granted on January 17, 2018, which are scheduled to vest January 17, 2021;
(f) $181,367, and $0, respectively, relate to restricted stock units and related dividend rights granted on January 17, 2018, in partial settlement of an award under the 2017 Bonus Plan, which are scheduled to vest January 17, 2021;
(g) $560,402, and $99,920, respectively, relate to performance share units and related dividend rights granted on January 17, 2018, which have an aggregate performance period that will end on December 31, 2020;
(h) $808,352, and $72,065, respectively, relate to restricted stock units and related dividend rights granted on January 17, 2019, which are scheduled to vest January 17, 2022; and
(i) $873,021, and $77,830, respectively, relate to performance share units and related dividend rights granted on January 17, 2019, which have an aggregate performance period that will end on December 31, 2021.

(5) Of the amount reported under each of the "Change in Control" column and the "Termination for Death or Disability" column:
(a) $282,911, and $75,665, respectively, relate to restricted stock units and related dividend rights granted on January 20, 2017, which are scheduled to vest on January 20, 2020;
(b) $339, 501, and $90,800, respectively, relate to performance share units and related dividend rights granted on January 17, 2017, where the performance period ended on December 31, 2019; however, the awards deemed "earned" were still deemed to be outstanding as of 12/31/2019, therefore a Change in Control or termination due to death or Disability could accelerate the time at which the awards could be settled with the executive;
(c) $1,837,350, and $491,400, respectively, relate to restricted stock units awarded January 20, 2017 as a retention grant which vest (i) 30% on January 20, 2021, (ii) 30% on January 20, 2022 and (iii) 40% on January 20, 2023, contingent upon continuous employment;
(d) $101,177, and $24,805, respectively, relate to restricted stock units and related dividend rights granted on February 28, 2017, in partial settlement of an award under the 2016 Bonus Plan, which are scheduled to vest on February 28, 2020;
(e) $487,306, and $86,887, respectively, relate to restricted stock units and related dividend rights granted on January 17, 2018, which are scheduled to vest January 17, 2021;
(f) $181,367, and $0, respectively, relate to restricted stock units and related dividend rights granted on January 17, 2018, in partial settlement of an award under the 2017 Bonus Plan, which are scheduled to vest January 17, 2021;
(g) $560,402, and $99,920, respectively, relate to performance share units and related dividend rights granted on January 17, 2018, which have an aggregate performance period that will end on December 31, 2020;
(h) $808,352, and $72,065, respectively, relate to the restricted stock units and related dividend rights granted on January 17, 2019, which are scheduled to vest January 17, 2022; and
(i) $873,021, and $77,830, respectively, relate to performance share units and related dividend rights granted on January 17, 2019, December 31, 2021.

(6) Of the amount reported under each of the "Change in Control" column and the "Termination for Death or Disability" column:
(a) $306,225, and $81,900, respectively, relate to restricted stock units and related dividend rights granted on January 20, 2017, which are scheduled to vest on January 20, 2020;
(b) $367,470, and $98,280, respectively, relate to performance share units and related dividend rights granted on January 17, 2017, where the performance period ended on December 31, 2019; however, the awards deemed "earned" were still deemed to be outstanding as of 12/31/2019, therefore a Change in Control or termination due to death or Disability could accelerate the time at which the awards could be settled with the executive;
(c) $2,449,800, and $655,200, respectively, relate to restricted stock units awarded January 20, 2017 as a retention grant which vest (i) 30% on January 20, 2021, (ii) 30% on January 20, 2022 and (iii) 40% on January 20, 2023, contingent upon continuous employment;
(d) $39,768, and $9,750, respectively, relate to restricted stock units and related dividend rights granted on February 28, 2017, in partial settlement of an award under the 2016 Bonus Plan, which are scheduled to vest on February 28, 2020;
(e) $1,020,750, and $227,500, respectively, relate to the restricted stock units awarded July 23, 2017 as a retention grant, which are scheduled to vest July 23, 2020, contingent upon continuous employment;
(f) $461,665, and $82,314, respectively, relate to restricted stock units and related dividend rights granted on January 17, 2018, which are scheduled to vest January 17, 2021;
(g) $137,883, and $0, respectively, relate to restricted stock units and related dividend rights granted on January 17, 2018, in partial settlement of an award under the 2017 Bonus Plan, which are scheduled to vest January 17, 2021;
(h) $530,915, and $94,662, respectively, relate to performance share units and related dividend rights granted on January 17, 2018, which have an aggregate performance period that will end on December 31, 2020;
(i) $808,352, and $72,065, respectively, relate to restricted stock units and related dividend rights granted on January 17, 2019, which are scheduled to vest January 17, 2022; and
(j) $873,021, and $77,830, respectively, relate to performance share units and related dividend rights granted on January 17, 2019, December 31, 2021.

Director Compensation

The following table sets forth the compensation earned by our non-employee directors for 2019:

Name	Fees Earned or Paid in Cash	Stock Awards (1)	Total Compensation
Charles R. Crisp	$ 145,000	$ 135,685	$280,685
Ershel C. Redd Jr.	107,500	135,685	243,185
Chris Tong	114,375	135,685	250,060
Laura C. Fulton	122,500	135,685	258,185
Waters S. Davis, IV	130,000	135,685	265,685
Rene R. Joyce	107,500	135,685	243,185
Robert B. Evans	125,000	135,685	260,685
Beth A. Bowman	113,125	135,685	248,810

(1) Amounts reported in the "Stock Awards" column represent the aggregate grant date fair value of restricted shares of our common stock with a one-year vesting period awarded to the non-employee directors under our Stock Incentive Plan, computed in accordance with FASB ASC Topic 718, disregarding the estimate of forfeitures. For a discussion of the assumptions and methodologies used to value the awards reported in this column, see the discussion contained in the Notes to Consolidated Financial Statements at Note 24 – Compensation Plans included in our Annual Report on Form 10-K for the year ended December 31, 2019. On January 17, 2019, each director received 3,168 restricted shares of our common stock in connection with their 2019 service on our Board of Directors, and the grant date fair value of each share of common stock computed in accordance with FASB ASC Topic 718 was $42.83. As of December 31, 2019, each of the directors still held the outstanding restricted shares granted to them in 2019, and none of our non-employee directors held any outstanding stock options.

Narrative to Director Compensation Table

For 2019, all non-employee directors received a cash retainer of $100,000. The lead director and the Chairman of the Audit Committee each received an additional annual retainer of $20,000, the Chairman of the Compensation Committee received an additional annual retainer of $15,000 and the Chairman of the Nominating and Governance Committee and the Chairman of the Risk Management Committee each received an additional retainer of $10,000. Each committee member received an additional annual retainer of $7,500 for each committee on which they served. Payment of non-employee director retainers are made quarterly. All non-employee directors are reimbursed for out-of-pocket expenses incurred in attending Board of Director and committee meetings.

A director who is also an employee receives no additional compensation for services as a director. Accordingly, Messrs. Whalen and Perkins have been omitted from the table. Because Mr. Perkins is a named executive officer for 2019, the Summary Compensation Table reflects the total compensation he received for services performed for us and our affiliates. Mr. Whalen, who serves as Executive Chairman of the Board is an executive officer who does not receive any additional compensation for services provided as a director. Due to the fact that Mr. Whalen is not a named executive officers his employee compensation is omitted from the table above and the Summary Compensation Table herein.

Director Long-term Equity Incentives. We granted equity awards in January 2019 to our non-employee directors serving at that time under the Stock Incentive Plan. Each of these directors received an award of 3,168 restricted shares of our common stock with a one-year vesting period. These grants reflect our intent to provide our directors with a target value of approximately $130,000 in annual long-term incentive awards. The awards are intended to align the long-term interests of our directors with those of our shareholders.

Changes for 2020

Director Compensation. For 2020, the annual cash retainer was increased to $115,000, the equity compensation portion of the retainer was increased to $150,000 and the retainer provided to directors for each committee on which they serve was eliminated. The lead director retainer was increased to $25,000 per year, the Audit Committee chair retainer was increased to $25,000 per year, the Compensation Committee chair retainer was increased to $20,000 per year, the Nominating and Governance Committee chair retainer was increased to $15,000 per year and the Risk Management Committee chair retainer was increased to $15,000 per year.

Director Long-term Equity Incentives. In January 2020, each of our non-employee directors received an award of 3,684 restricted shares of our common stock under the Stock Incentive Plan with a one-year vesting period, which reflects our desire to increase the target value of the annual awards to approximately $150,000 per year.

Pay Ratio Disclosures

As required by Section 953(b) of the Dodd-Frank Wall Street Reform and Consumer Protection Act, and Item 402(u) of Regulation S-K, we are providing the following information about the relationship of the annual total compensation of our employees and the annual total compensation of Joe Bob Perkins, our Chief Executive Officer (our “CEO”).

For 2019, our last completed fiscal year:

- The median of the annual total compensation of all employees of our company (other than the CEO) was $114,112,
- The annual total compensation of Mr. Perkins was $12,460,549.
- Based on this information, for 2019 the ratio of the annual total compensation of our CEO to the median of the annual total compensation of all employees (“CEO Pay Ratio”) was reasonably estimated to be 109 to 1.

To calculate the CEO Pay Ratio we must identify the median of the annual total compensation of all our employees, as well as to determine the annual total compensation of our median employee and our CEO. To these ends, we took the following steps:

- We determined that, as of December 31, 2019, our employee population consisted of approximately 2,680 individuals. This population consisted of our full-time and part-time employees, as we do not have temporary or seasonal workers.
- We used a consistently applied compensation measure to identify our median employee of comparing the amount of salary or wages, bonuses, company contributions under our 401(k) plan, and the grant date fair value of equity awards determined under FASB ASC Topic 718. We identified our median employee by consistently applying this compensation measure to all of our employees included in our analysis. For individuals hired after January 1, 2019 that were included in the employee population, we calculated these compensation elements on an annualized basis. We did not make any cost of living adjustments in identifying the median employee
- We combined all of the elements of the median employee’s compensation for the 2019 year in accordance with the requirements of Item 402(c)(2)(x) of Regulation S-K, resulting in annual total compensation of $114,112.
- With respect to the annual total compensation of our CEO, we used the amount reported in the “Total” column of our 2019 Summary Compensation Table included in Item 11 of Part III of this Annual Report.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters.

The following table sets forth information regarding the beneficial ownership of TRC common stock as of February 1, 2020 (unless otherwise indicated) held by:

- each person who beneficially owns 5% or more of TRC’s then outstanding shares of common stock;
- each of TRC’s named executive officers;
- each of TRC’s directors; and
- all of TRC’s executive officers and directors as a group.

TRC owns all of our outstanding common units. As of February 1, 2020, none of TRC’s directors or executive officers owned any preferred shares of TRC or Preferred Units.

Beneficial ownership is determined under the rules of the SEC. In general, these rules attribute beneficial ownership of securities to persons who possess sole or shared voting power and/or investment power with respect to those securities and include, among other things, securities that an individual has the right to acquire within 60 days. Unless otherwise indicated, the stockholders identified in the table below have sole voting and investment power with respect to all securities shown as beneficially owned by them. Percentage ownership calculations for any security holder listed in the table below are based on 233,046,042 shares of TRC's common stock outstanding on February 1, 2020.

	Targa Resources Corp.	
Name of Beneficial Owner (1)	**Common Stock Beneficially Owned**	**Percentage of Common Stock Beneficially Owned**
The Vanguard Group (2)	22,740,318	9.76%
Tortoise Capital Advisors, L.L.C (3)	15,282,387	6.56%
T. Rowe Price Associates, Inc. (4)	13,733,989	5.89%
BlackRock, Inc. (5)	13,662,454	5.86%
Harvest Fund Advisors LLC (6)	10,771,264	4.62%
Joe Bob Perkins (7)	800,974	*
Matthew J. Meloy	69,147	*
Jennifer R. Kneale	10,336	*
Patrick J. McDonie	81,791	*
D. Scott Pryor	51,293	*
Robert M. Muraro	23,973	*
Rene R. Joyce (8)	1,063,187	*
James W. Whalen (9)	699,451	*
Charles R. Crisp	122,123	*
Chris Tong (10)	93,229	*
Robert B. Evans (11)	85,506	*
Ershel C. Redd Jr.	19,962	*
Laura C. Fulton	14,995	*
Waters S. Davis, IV	12,279	*
Beth A. Bowman	5,139	*
All directors and executive officers as a group (18 persons)	3,751,142	1.61%

* Less than 1%.

(1) Unless otherwise indicated, the address for all beneficial owners in this table is 811 Louisiana, Suite 2100, Houston, Texas 77002.

(2) As reported on Schedule 13G/A as of December 31, 2019 and filed with the SEC on February 12, 2020, the business address for The Vanguard Group is 100 Vanguard Blvd. Malvern, PA 19355. The Vanguard Group has sole voting power over 180,370 shares of common stock, shared voting power over 66,068 shares of common stock, sole dispositive power over 22,523,432 shares of common stock and shared dispositive power over 216,886 shares of common stock.

(3) As reported on Schedule 13G as of December 31, 2019 and filed with the SEC on February 14, 2020, the business address for Tortoise Capital Advisors, L.L.C. is 5100 W 115th Place, Leawood, KS 66211. Tortoise Capital Advisors, L.L.C. has sole voting power over 145,209 shares of common stock, shared voting power over 12,865,304 shares of common stock, sole dispositive power over 145,209 shares of common stock and shared dispositive power over 15,137,178 shares of common stock.

(4) As reported on Schedule 13G as of December 31, 2019 and filed with the SEC on February 14, 2020, the business address for T. Rowe Price Associates, Inc. is 100 E. Pratt Street, Baltimore, MD 21202. T. Rowe Price Associates, Inc. has sole voting power over 3,486,752 shares of common stock and sole dispositive power over 13,733,989 shares of common stock.

(5) As reported on Schedule 13G/A as of December 31, 2019 and filed with the SEC on February 6, 2020, the business address for BlackRock, Inc. is 55 East 52nd Street New York, NY 10055. BlackRock, Inc. has sole voting power over 11,923,251 shares of common stock and sole dispositive power over 13,662,454 shares of common stock.

(6) As reported on Schedule 13G/A as of December 31, 2019 and filed with the SEC on February 14, 2020, the business address for Harvest Fund Advisors LLC is s 100 W. Lancaster Avenue, Suite 200, Wayne, PA 19087. Harvest Fund Advisors LLC has sole voting power and sole dispositive power over 10,771,264 shares of common stock.

(7) Shares of common stock beneficially owned by Mr. Perkins include: (i) 402,483 shares issued to the Perkins Blue House Investments Limited Partnership ("PBHILP") and (ii) 93 shares held by Mr. Perkins' wife. Mr. Perkins is the sole member of JBP GP, L.L.C., one of the general partners of the PBHILP.

(8) Shares of common stock beneficially owned by Mr. Joyce include: (i) 223,759 shares issued to The Rene Joyce 2010 Grantor Retained Annuity Trust, of which Mr. Joyce and his wife are co-trustees and have shared voting and investment power; and (ii) 561,292 shares issued to The Kay Joyce 2010 Family Trust, of which Mr. Joyce's wife is trustee and has sole voting and investment power.

(9) Shares of common stock beneficially owned by Mr. Whalen include (i) 345,999 shares issued to the Whalen Family Investments Limited Partnership and (ii) 167,050 shares issued to the Whalen Family Investments Limited Partnership 2.
(10) Shares of common stock beneficially owned by Mr. Tong include 434 shares held by Mr. Tong's wife.
(11) Shares of common stock beneficially owned by Mr. Evans include 27,000 shares held by Mr. Evan's wife.

Securities Authorized for Issuance under Equity Compensation Plans

The following table sets forth certain information as of December 31, 2019 regarding TRC's long-term incentive plans, under which TRC common stock is authorized for issuance to employees, consultants and directors of TRC, our general partner and their affiliates. TRC's sole equity compensation plan, under which it will make equity grants, is its Amended and Restated 2010 Stock Incentive Plan, which was approved by TRC stockholders on May 22, 2017.

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders (1)	-	-	8,172,815

(1) Generally, awards of restricted stock, restricted stock units and performance share units to our officers and employees under the Stock Incentive Plan are subject to vesting over time as determined by the Compensation Committee of TRC and, prior to vesting, are subject to forfeiture. Stock incentive plan awards may vest in other circumstances, as approved by the Compensation Committee and reflected in an award agreement. Restricted stock, restricted stock units and performance share units are issued, subject to vesting, on the date of grant. The Compensation Committee of TRC may provide that dividends on restricted stock, restricted stock units or performance share units are subject to vesting and forfeiture provisions, in which cash such dividends would be held, without interest, until they vest or are forfeited.

Item 13. Certain Relationships and Related Transactions, and Director Independence.

As a result of the TRC/TRP Merger, which was completed on February 17, 2016, Targa owns all of our outstanding common units. In addition, Targa owns a 2% general partner interest in us. Our total outstanding common units as of February 10, 2017 totaled 236,595,048. In addition, Targa owns a 2% general partner interest in us, which is held through a 100% ownership interest in our general partner.

Distributions and Payments to Targa and its Affiliates

The following table summarizes the distributions and payments made and to be made by us to Targa and its affiliates in connection with our ongoing operation and any liquidation of us. These distributions and payments were determined by and among affiliated entities and, consequently, are not the result of arm's-length negotiations.

Operational Stage	
Distributions of available cash to Targa and its affiliates	Please see "Item 5. Market for Registrant's Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities—Distributions of Available Cash."
Payments to Targa and its affiliates	We reimburse Targa for the payment of certain operating expenses and for the provision of various general and administrative services for our benefit. See "Reimbursement of Operating and General and Administrative Expense."
Withdrawal or removal of our general partner	If our general partner withdraws or is removed, its general partner interest will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.
Liquidation Stage	
Liquidation	Upon our liquidation, the partners, including our general partner, will be entitled to receive liquidating distributions according to their respective capital account balances.

Partnership Agreement

Our Partnership Agreement with Targa governs the reimbursement of Targa and its affiliates for costs incurred on our behalf, competition and indemnification matters. The Partnership Agreement provides that Targa and its affiliates are reimbursed for all direct and indirect expenses, as well as expenses otherwise allocable to us in connection with the operation of our business, incurred on our behalf.

Reimbursement of Operating and General and Administrative Expense

Under the terms of our Partnership Agreement, we reimburse Targa for all direct and indirect expenses, as well as expenses otherwise allocable to us in connection with the operation of our business, incurred on our behalf, which includes certain operating and direct expenses, including compensation and benefits of operating personnel, including 401(k), pension and health insurance benefits, and for the provision of various general and administrative services for our benefit. Targa performs centralized corporate functions for us, such as legal, accounting, treasury, insurance, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes, engineering and marketing. Other than Targa's direct costs of being a public reporting company, substantially all of Targa's general and administrative costs have been and will continue to be allocated to us, so long as Targa's only cash-generating assets consist of its interest in us.

Competition

Targa is not restricted under our Partnership Agreement from competing with us. Targa may acquire, construct or dispose of additional midstream energy or other assets in the future without any obligation to offer us the opportunity to purchase or construct those assets.

Indemnification Agreements

Indemnification Agreements with Directors and Officers

We and our general partner have entered into Indemnification Agreements (each, an "Indemnification Agreement") with individuals who were independent directors of Targa Resources GP LLC (each, an "Indemnitee") prior to the TRC/TRP Merger. Each Indemnification Agreement provides that each of us and Targa Resources GP LLC will indemnify and hold harmless each Indemnitee against Expenses (as defined in the Indemnification Agreement) to the fullest extent permitted or authorized by law, including the Delaware Revised Uniform Limited Partnership Act and the Delaware Limited Liability Company Act in effect on the date of the agreement or as such laws may be amended to provide more advantageous rights to the Indemnitee. If such indemnification is unavailable as a result of a court decision and if we or Targa Resources GP LLC are jointly liable in the proceeding with the Indemnitee, we and Targa Resources GP LLC will contribute funds to the Indemnitee for his or her Expenses (as defined in the Indemnification Agreement) in proportion to relative benefit and fault of us or Targa Resources GP LLC on the one hand and Indemnitee on the other in the transaction giving rise to the proceeding.

Each Indemnification Agreement also provides that we and Targa Resources GP LLC will indemnify and hold harmless the Indemnitee against Expenses incurred for actions taken as a director or officer of us or Targa Resources GP LLC or for serving at the request of us or Targa Resources GP LLC as a director or officer or another position at another corporation or enterprise, as the case may be, but only if no final and non-appealable judgment has been entered by a court determining that, in respect of the matter for which the Indemnitee is seeking indemnification, the Indemnitee acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal proceeding, the Indemnitee acted with knowledge that the Indemnitee's conduct was unlawful. Each Indemnification Agreement also provides that we and Targa Resources GP LLC must advance payment of certain Expenses to the Indemnitee, including fees of counsel, subject to receipt of an undertaking from the Indemnitee to return such advance if it is ultimately determined that the Indemnitee is not entitled to indemnification.

Targa Resources Corp., the holder of all of our common units, has entered into Indemnification Agreements (each, a "Parent Indemnification Agreement") with each director and officer of Targa (each, a "Parent Indemnitee"). Each Parent Indemnification Agreement provides that Targa Resources Corp. will indemnify and hold harmless each Parent Indemnitee for Expenses (as defined in the Parent Indemnification Agreements) to the fullest extent permitted or authorized by law, including the Delaware General Corporation Law, in effect on the date of the agreement or as it may be amended to provide more advantageous rights to the Parent Indemnitee. If such indemnification is unavailable as a result of a court decision and if Targa Resources Corp. and the Indemnitee are jointly liable in the proceeding, Targa Resources Corp. will contribute funds to the Parent Indemnitee for his or her expenses in proportion to relative benefit and fault of Targa Resources Corp. and Parent Indemnitee in the transaction giving rise to the proceeding.

Each Indemnification Agreement also provides that Targa Resources Corp. will indemnify the Parent Indemnitee for monetary damages for actions taken as a director or officer of Targa Resources Corp. or for serving at Targa's request as a director or officer or another position at another corporation or enterprise, as the case may be but only if (i) the Parent Indemnitee acted in good faith and, in the case of conduct in his or her official capacity, in a manner he reasonably believed to be in the best interests of Targa Resources Corp. and, in all other cases, not opposed to the best interests of Targa Resources Corp. and (ii) in the case of a criminal proceeding, the Parent Indemnitee must have had no reasonable cause to believe that his or her conduct was unlawful. Each Parent Indemnification Agreement also provides that Targa Resources Corp. must advance payment of certain Expenses to the Parent Indemnitee, including fees of counsel, subject to receipt of an undertaking from the Parent Indemnitee to return such advance if it is ultimately determined that the Parent Indemnitee is not entitled to indemnification.

Transactions with Related Persons

Relationship with Sajet Resources LLC

In December 2010, immediately prior to Targa's initial public offering, Sajet Resources LLC ("Sajet") was spun-off from Targa. At the time, Rene Joyce, James Whalen and Joe Bob Perkins, directors of Targa, were also directors of Sajet. Joe Bob Perkins, James Whalen, Michael Heim, Jeffrey McParland, Paul Chung, and Matthew Meloy, executive officers of Targa at the time, were also executive officers of Sajet. The current directors of Sajet are Paul Chung, Jennifer Kneale, Chris McEwan and Matthew Meloy. The current executive officers of Sajet are Joe Bob Perkins, Matthew Meloy, Robert Muraro, Jennifer Kneale, Paul Chung and Julie Boushka. The primary assets of Sajet are real property. Sajet also holds (i) an ownership interest in Floridian Natural Gas Storage Company, LLC through a December 2016 merger with Tesla Resources LLC and (ii) an ownership interest in Allied CNG Ventures LLC. Former holders of our pre-IPO common equity, including certain of our current and former executives, managers and directors collectively own an 18% interest in Sajet. We hold three outstanding promissory notes from Sajet in the amounts of $9.9 million, $0.5 million and $0.2 million. The interest rate on each of the promissory notes accrues at the prime rate plus six percent annum.
Since March 2018, Sajet has been accounted for on a consolidated basis in our consolidated financial statements.

Relationship with Apache Corp.

Rene R. Joyce, a director of Targa and of our general partner, is also a director of Apache Corporation ("Apache") with whom we purchase and sell natural gas and NGLs and engage in construction services. During 2019, we made sales to Apache of $0.5 million and purchases of $102.8 million from Apache.

Relationship with Kansas Gas Service and NJR Energy Services Company

Robert B. Evans, a director of Targa and our general partner, is also a director of ONE Gas, Inc. ("ONE"). We have commercial arrangements with Kansas Gas Service ("Kansas Gas"), a division of ONE. During 2019, we transacted sales of $22.2 million with Kansas Gas.

Mr. Evans also serves as a director New Jersey Resources Corporation ("NJR"). We have gas purchase and sale arrangements with NJR Energy Services Company ("NJR Services"), a subsidiary of NJR. During 2019, we made sales of $9.1 million to NJR Services and purchases of $29.7 million from NJR Services.

Relationships with Southern Company Gas, EOG Resources Inc., and Intercontinental Exchange, Inc.

Charles R. Crisp, a director of the Company and of our general partner, is a director of Southern Company Gas, parent company of Sequent Energy Management, LP ("Sequent") and Northern Illinois Gas Company d/b/a NICOR Energy ("NICOR"). We purchase and sell natural gas and NGL products from and to Sequent and sell natural gas products to NICOR. In addition, we purchase electricity from Mississippi Power ("MS Power"), an affiliate of Southern Company, parent company of Southern Company Gas. Mr. Crisp also serves as a director of EOG Resources, Inc. ("EOG"), from whom we purchase natural gas and from whom, together with EOG's subsidiary EOG Resources Marketing, Inc. ("EOG Marketing"), we purchase crude oil. We also bill EOG and EOG Marketing for well connections to our gathering systems and associated equipment, and for services to operate certain EOG and jointly owned gas and crude oil gathering facilities. Mr. Crisp is also a director of Intercontinental Exchange, Inc. ("ICE Group"), parent company of ICE US OTC Commodity Markets LLC from whom we purchase brokerage services, NYSE Market Inc. and ICE NGX Canada Inc., which provide platform services utilized by us for the purchase and sale of physical gas and natural gas liquids with third parties. The following table shows our transactions with each of these entities during 2019:

Entity	Sales	Purchases
	(In millions)	
Sequent	$ 57.9	$ 7.0
NICOR	0.5	—
MS Power	—	0.5
EOG	20.9	7.7
ICE Group	11.8	12.9

Relationship with Southwest Energy LP

Ershel C. Redd Jr., a director of Targa and of our general partner, has an immediate family member who is an officer and part owner of Southwest Energy LP ("Southwest Energy") from and to whom we purchase and sell natural gas and NGL products. During 2019, we made sales to Southwest Energy of $16.9 million and purchases of $3.5 million from Southwest Energy.

Relationship with Intercontinental Exchange, Inc.

Jennifer R. Kneale, Chief Financial Officer of Targa and of our general partner, has an immediate family member who is an officer of ICE Group. During 2019, we made sales to ICE Group of $11.8 million and purchases of $12.9 million from ICE Group.

Relationship with Kosmos Energy Gulf of Mexico Operations

Chris Tong, a director of Targa and of our general partner, was also a director of Kosmos Energy Ltd. ("Kosmos") from 2011 until September 2019. We have gas purchase and sale arrangements with Kosmos Energy Gulf of Mexico Operations ("Kosmos Energy"), a subsidiary of Kosmos. During 2019, we made purchases of $0.5 million from Kosmos Energy.

These transactions were at market prices consistent with similar transactions with other nonaffiliated entities.

Conflicts of Interest

Conflicts of interest exist and may arise in the future as a result of the relationships between our general partner and its affiliates (including Targa) on the one hand and our partnership and our limited partners, on the other hand. The directors and officers of Targa Resources GP LLC have fiduciary duties to manage Targa and our general partner in a manner beneficial to its owners. At the same time, our general partner has a fiduciary duty to manage our partnership in a manner beneficial to us and our unitholders.

Whenever a conflict arises between our general partner and its affiliates on the one hand and us or any other partner on the other hand, our general partner will resolve that conflict. Our partnership agreement contains provisions that modify and limit our general partner's fiduciary duties to our unitholders. Our partnership agreement also restricts the remedies available to unitholders for actions taken that, without those limitations, might constitute breaches of fiduciary duty.

Our general partner will not be in breach of its obligations under the partnership agreement or its duties to us or our unitholders if the resolution of the conflict is:

- approved by the conflicts committee, although our general partner is not obligated to seek such approval;
- approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner or any of its affiliates;
- on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or
- fair and reasonable to us, taking into account the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to us.

Our general partner may, but is not required to, seek the approval of such resolution from the conflicts committee of its board of directors. If our general partner does not seek approval from the conflicts committee and its board of directors determines that the resolution or course of action taken with respect to the conflict of interest satisfies either of the standards set forth in the third or fourth bullet points above, then it will be presumed that, in making its decision, the board of directors acted in good faith and in any proceeding brought by or on behalf of any limited partner of the partnership, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption. Unless the resolution of a conflict is specifically provided for in our partnership agreement, our general partner or the conflicts committee may consider any factors it determines in good faith to consider when resolving a conflict. When our partnership agreement provides that someone act in good faith, it requires that person to believe he is acting in the best interests of the partnership.

Review, Approval or Ratification of Transactions with Related Persons

If a conflict or potential conflict of interest arises between our general partner and its affiliates (including Targa) on the one hand and our partnership and our limited partners, on the other hand, the resolution of any such conflict or potential conflict is addressed as described under "−Conflicts of Interest."

Pursuant to Targa's Code of Conduct, our officers and directors are required to avoid any activity or interest that creates a conflict of interest between them and Targa or any of its subsidiaries, unless the conflict is disclosed and pre-approved by the Board of Directors.

Director Independence

The NYSE does not require a listed limited partnership like us to have a majority of independent directors on the board of directors of our general partner or to establish a compensation committee or a nominating/governance committee. Our general partner has a standing Audit Committee that consists of three directors: Mr. Redd and Mses. Fulton and Bowman. The board of directors of our general partner has affirmatively determined that Mr. Redd and Mses. Fulton and Bowman are independent as described in the rules of the NYSE and the Exchange Act for purposes of serving on the board of directors and the Audit Committee.

To be independent under the NYSE rules, a company's board of directors must affirmatively determine that the director has no material relationship with the company (directly as a partner, stockholder or officer of an organization that has a relationship with the company). The board of directors of our general partner has made no such determination with respect to Messrs. Joyce, Perkins and Whalen because the NYSE rules do not require us to have a majority of independent directors. As such, Messrs. Joyce, Perkins and Whalen are not independent under NYSE rules applicable to service on compensation and nominating/governance committees.

Item 14. Principal Accounting Fees and Services.

We have engaged PricewaterhouseCoopers LLP as our independent principal accountant. The following table summarizes fees we were billed by PricewaterhouseCoopers LLP (or included in Targa's general and administrative expense allocation to us) for independent auditing, tax and related services for each of the last two fiscal years:

	2019	2018
	(In millions)	
Audit fees (1)	$ 3.8	$ 3.9
Audit-related fees (2)	—	—
Tax fees (3)	—	—
All other fees (4)	0.1	—
	$ 3.9	$ 3.9

(1) Audit fees represent amounts billed for each of the years presented for professional services rendered in connection with (i) the integrated audit of our annual financial statements and internal control over financial reporting, (ii) the review of our quarterly financial statements or (iii) those services normally provided in connection with statutory and regulatory filings or engagements including comfort letters, consents and other services related to SEC matters. This information is presented as of the latest practicable date for this Annual Report.
(2) Audit-related fees represent amounts we were billed in each of the years presented for assurance and related services that are reasonably related to the performance of the annual audit or quarterly reviews of our financial statements and are not reported under audit fees.
(3) Tax fees represent amounts we were billed in each of the years presented for professional services rendered in connection with tax compliance.
(4) All other fees represent amounts we were billed in each of the years presented for services not classifiable under the other categories listed in the table above.

All services provided by our independent principal accountant are subject to pre-approval by the Audit Committee of our general partner. The Audit Committee of our general partner is informed of each engagement of the independent principal accountant to provide services under the policy. The Audit Committee of our general partner has approved the use of PricewaterhouseCoopers LLP as our independent principal accountant. All of the services of PricewaterhouseCoopers LLP for 2019 and 2018 described above were pre-approved by the Audit Committee.

PART IV

Item 15. Exhibits, Financial Statement Schedules.

(a)(1) Financial Statements

Our Consolidated Financial Statements are included under Part II, Item 8 of the Annual Report. For a listing of these statements and accompanying footnotes, see "Index to Consolidated Financial Statements" on Page F-1 in this Annual Report.

(a)(2) Financial Statement Schedules

All schedules have been omitted because they are either not applicable, not required or the information called for therein appears in the consolidated financial statements or notes thereto.

(a)(3) Exhibits

Number	Description
2.1***	Purchase and Sale Agreement, dated September 18, 2007, by and between Targa Resources Holdings LP and Targa Resources Partners LP (incorporated by reference to Exhibit 2.1 to Targa Resources Partners LP's Current Report on Form 8-K filed September 21, 2007 (File No. 001-33303)).
2.2	Amendment to Purchase and Sale Agreement, dated October 1, 2007, by and between Targa Resources Holdings LP and Targa Resources Partners LP (incorporated by reference to Exhibit 2.2 to Targa Resources Partners LP's Current Report on Form 8-K filed October 24, 2007 (File No. 001-33303)).
2.3	Purchase and Sale Agreement dated July 27, 2009, by and between Targa Resources Partners LP, Targa GP Inc. and Targa LP Inc. (incorporated by reference to Exhibit 2.1 to Targa Resources Partners LP's Current Report on Form 8-K filed July 29, 2009 (File No. 001-33303)).
2.4	Purchase and Sale Agreement, dated March 31, 2010, by and among Targa Resources Partners LP, Targa LP Inc., Targa Permian GP LLC and Targa Midstream Holdings LLC (incorporated by reference to Exhibit 2.1 to Targa Resources Partners LP's Current Report on Form 8-K filed April 1, 2010 (File No. 001-33303)).
2.5	Purchase and Sale Agreement, dated August 6, 2010, by and between Targa Resources Partners LP and Targa Versado Holdings LP (incorporated by reference to Exhibit 2.1 to Targa Resources Partners LP's Current Report on Form 8-K filed August 9, 2010 (File No. 001-33303)).
2.6	Purchase and Sale Agreement, dated September 13, 2010, by and between Targa Resources Partners LP and Targa Versado Holdings LP (incorporated by reference to Exhibit 2.1 to Targa Resources Partners LP's Current Report on Form 8-K filed September 17, 2010 (File No. 001-33303)).
2.7***	Membership Interest Purchase and Sale Agreement, dated November 14, 2012, by and among Targa Resources Partners LP, Saddle Butte Pipeline LLC, Saddle Butte Fort Berthold Gathering, LLC and Saddle Butte Assets, LLC (incorporated by reference to Exhibit 2.1 to Targa Resources Partners LP's Current Report on Form 8-K filed November 15, 2012 (File No. 001-33303)).
2.8***	Agreement and Plan of Merger, by and among Targa Resources Corp., Trident GP Merger Sub LLC, Atlas Energy, L.P. and Atlas Energy GP, LLC, dated October 13, 2014 (incorporated by reference to Exhibit 2.1 to Targa Resources Partners LP's Current Report on Form 8-K filed October 20, 2014 (File No. 001-33303)).
2.9***	Agreement and Plan of Merger, by and among Targa Resources Corp., Targa Resources Partners LP, Targa Resources GP LLC, Trident MLP Merger Sub LLC, Atlas Energy, L.P., Atlas Pipeline Partners, L.P. and Atlas Pipeline Partners GP, LLC, dated October 13, 2014 (incorporated by reference to Exhibit 2.2 to Targa Resources Partners LP's Current Report on Form 8-K filed October 20, 2014 (File No. 001-33303)).
2.10***	Agreement and Plan of Merger, dated as of November 2, 2015, by and among Targa Resources Corp., Spartan Merger Sub LLC, Targa Resources Partners LP and Targa Resources GP LLC (incorporated by reference to Exhibit 2.1 to Targa Resources Partners LP's Current Report on Form 8-K filed November 6, 2015 (File No. 001-33303)).
2.11***	Membership Interest Purchase and Sale Agreement, dated January 22, 2017, by and between Targa Resources Partners LP and Outrigger Delaware Midstream, LLC (incorporated by reference to Exhibit 2.1 to Targa Resources Partners LP's Current Report on Form 8-K filed January 23, 2017 (File No. 001-33303)).

2.12***	Membership Interest Purchase and Sale Agreement, dated January 22, 2017, by and between Targa Resources Partners LP and Outrigger Energy, LLC (incorporated by reference to Exhibit 2.2 to Targa Resources Partners LP's Current Report on Form 8-K filed January 23, 2017 (File No. 001-33303)).
2.13***	Membership Interest Purchase and Sale Agreement, dated January 22, 2017, by and between Targa Resources Partners LP and Outrigger Midland Midstream, LLC (incorporated by reference to Exhibit 2.3 to Targa Resources Partners LP's Current Report on Form 8-K filed January 23, 2017 (File No. 001-33303)).
3.1	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)).
3.2	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)).
3.3	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)).
3.4	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 filed December 12, 2017(File No. 001-33303)).
3.5	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 Unit Certificate representing common units (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP's Annual Report on Form 10-K filed April 2, 2007 (File No. 001-33303)).
4.2	Indenture dated as of October 25, 2012 among Targa Resources Partners LP, Targa Resources Partners Finance Corporation and the Guarantors named therein 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 October 26, 2012 (File No. 001-33303)).
4.3	Registration Rights Agreement dated as of October 25, 2012 among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors and Merrill Lynch, Pierce, Fenner & Smith Incorporated, Deutsche Bank Securities Inc., Wells Fargo Securities, LLC, Barclays Capital Inc. and RBS Securities Inc., as representatives of the several initial purchasers (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP's Current Report on Form 8-K filed October 26, 2012 (File No. 001-33303)).
4.4	Registration Rights Agreement dated as of December 10, 2012 among the Issuers, the Guarantors and Merrill Lynch, Pierce, Fenner & Smith Incorporated, Deutsche Bank Securities Inc., Wells Fargo Securities, LLC, Barclays Capital Inc. and RBS Securities Inc., as representatives of the several initial purchasers. (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP's Current Report on Form 8-K filed December 10, 2012 (File No. 001-33303)).
4.5	Supplemental Indenture dated March 10, 2017 to Indenture dated October 25, 2012, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.3 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed May 4, 2017 (File No. 001-33303)).
4.6	Supplemental Indenture dated June 16, 2017 to Indenture dated October 25, 2012, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.3 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed November 3, 2017 (File No. 001-33303)).
4.7	Supplemental Indenture dated December 18, 2017 to Indenture dated October 25, 2012, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.7 to Targa Resources Partners LP's Annual Report on Form 10-K filed February 16, 2018 (File No. 001-33303)).
4.8	Supplemental Indenture dated January 9, 2018 to Indenture dated October 25, 2012, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.8 to Targa Resources Partners LP's Annual Report on Form 10-K filed February 16, 2018 (File No. 001-33303)).

4.9	Supplemental Indenture dated July 24, 2018 to Indenture dated October 25, 2012, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.4 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed August 9, 2018 (File No. 001-33303)).
4.10	Supplemental Indenture dated July 19, 2019 to Indenture dated October 25, 2012, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed August 9, 2019 (File No. 001-33303)).
4.11	Indenture dated as of May 14, 2013 among the Issuers and 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 May 14, 2013 (File No. 001-33303)).
4.12	Registration Rights Agreement dated as of May 14, 2013 among the Issuers, the Guarantors and Wells Fargo Securities, LLC, Barclays Capital Inc., Deutsche Bank Securities Inc., J.P. Morgan Securities LLC and RBC Capital Markets, LLC, as representatives of the several initial purchasers (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP's Current Report on Form 8-K filed May 14, 2013 (File No. 001-33303)).
4.13	Supplemental Indenture dated March 10, 2017 to Indenture dated May 14, 2013, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.4 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed May 4, 2017 (File No. 001-33303)).
4.14	Supplemental Indenture dated June 16, 2017 to Indenture dated May 14, 2013, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.4 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed November 3, 2017 (File No. 001-33303)).
4.15	Supplemental Indenture dated December 18, 2017 to Indenture dated May 14, 2013, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.13 to Targa Resources Partners LP's Annual Report on Form 10-K filed February 16, 2018 (File No. 001-33303)).
4.16	Supplemental Indenture dated January 9, 2018 to Indenture dated May 14, 2013, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.14 to Targa Resources Partners LP's Annual Report on Form 10-K filed February 16, 2018 (File No. 001-33303)).
4.17	Supplemental Indenture dated July 24, 2018 to Indenture dated May 14, 2013, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.5 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed August 9, 2018 (File No. 001-33303)).
4.18	Supplemental Indenture dated July 19, 2019 to Indenture dated May 14, 2013, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.3 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed August 9, 2019 (File No. 001-33303)).
4.19	Indenture, dated as of September 14, 2015, among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors named therein 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 September 15, 2015 (File No. 001-33303)).
4.20	Registration Rights Agreement, dated as of September 14, 2015, among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors named therein and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as representative of the several initial purchasers (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP's Current Report on Form 8-K filed September 15, 2015 (File No. 001-33303)).

4.21	Supplemental Indenture dated March 10, 2017 to Indenture dated September 14, 2015, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.7 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed May 4, 2017 (File No. 001-33303)).
4.22	Supplemental Indenture dated June 16, 2017 to Indenture dated September 14, 2015, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.7 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed November 3, 2017 (File No. 001-33303)).
4.23	Supplemental Indenture dated December 18, 2017 to Indenture dated September 14, 2015, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.25 to Targa Resources Partners LP's Annual Report on Form 10-K filed February 16, 2018 (File No. 001-33303)).
4.24	Supplemental Indenture dated January 9, 2018 to Indenture dated September 14, 2015, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.26 to Targa Resources Partners LP's Annual Report on Form 10-K filed February 16, 2018 (File No. 001-33303)).
4.25	Supplemental Indenture dated July 24, 2018 to Indenture dated September 14, 2015, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.7 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed August 9, 2018 (File No. 001-33303)).
4.26	Supplemental Indenture dated July 19, 2019 to Indenture dated September 14, 2015, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.4 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed August 9, 2019 (File No. 001-33303)).
4.27	Indenture dated as of October 6, 2016 among Targa Resources Partners LP, Targa Resources Partners Finance Corporation and 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 October 12, 2016 (File No. 001-33303)).
4.28	Registration Rights Agreement dated as of October 6, 2016 among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors and Wells Fargo Securities, LLC, 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 October 12, 2016 (File No. 001-33303)).
4.29	Registration Rights Agreement dated as of October 6, 2016 among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors and Wells Fargo Securities, LLC, 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 October 12, 2016 (File No. 001-33303)).
4.30	Supplemental Indenture dated March 10, 2017 to Indenture dated October 6, 2016, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.8 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed May 4, 2017 (File No. 001-33303)).
4.31	Supplemental Indenture dated June 16, 2017 to Indenture dated October 6, 2016, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.8 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed November 3, 2017 (File No. 001-33303)).
4.32	Supplemental Indenture dated December 18, 2017 to Indenture dated October 6, 2016, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.32 to Targa Resources Partners LP's Annual Report on Form 10-K filed February 16, 2018 (File No. 001-33303)).
4.33	Supplemental Indenture dated January 9, 2018 to Indenture dated October 6, 2016, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.33 to Targa Resources Partners LP's Annual Report on Form 10-K filed February 16, 2018 (File No. 001-33303)).

4.34	Supplemental Indenture dated July 24, 2018 to Indenture dated October 6, 2016, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.8 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed August 9, 2018 (File No. 001-33303)).
4.35	Supplemental Indenture dated July 19, 2019 to Indenture dated October 6, 2016, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.5 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed August 9, 2019 (File No. 001-33303)).
4.36	Indenture dated as of October 17, 2017 among the Issuers and the Guarantors and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP's Current Report on Form 8-K (File No. 001-33303) filed October 17, 2017).
4.37	Registration Rights Agreement dated as of October 17, 2017 among the Issuers, the Guarantors and Citigroup Global Markets Inc., as representative of the several Initial Purchasers party thereto (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP's Current Report on Form 8-K (File No. 001-33303) filed October 17, 2017).
4.38	Supplemental Indenture dated December 18, 2017 to Indenture dated October 17, 2017, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.36 to Targa Resources Partners LP's Annual Report on Form 10-K filed February 16, 2018 (File No. 001-33303)).
4.39	Supplemental Indenture dated January 9, 2018 to Indenture dated October 17, 2017, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.37 to Targa Resources Partners LP's Annual Report on Form 10-K filed February 16, 2018 (File No. 001-33303)).
4.40	Supplemental Indenture dated July 24, 2018 to Indenture dated October 17, 2017, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.9 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed August 9, 2018 (File No. 001-33303)).
4.41	Supplemental Indenture dated July 19, 2019 to Indenture dated October 17, 2017, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.6 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed August 9, 2019 (File No. 001-33303)).
4.42	Indenture dated as of April 12, 2018 among the Issuers, the Guarantors and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP's Current Report on Form 8-K (File No. 001-33303) filed April 16, 2018).
4.43	Registration Rights Agreement dated as of April 12, 2018 among the Issuers, the Guarantors and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as representative of the several Initial Purchasers party thereto (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP's Current Report on Form 8-K (File No. 001-33303) filed April 16, 2018).
4.44	Supplemental Indenture dated July 24, 2018 to Indenture dated April 12, 2018, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.10 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed August 9, 2018 (File No. 001-33303)).
4.45	Supplemental Indenture dated July 19, 2019 to Indenture dated April 12, 2018, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.7 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed August 9, 2019 (File No. 001-33303)).
4.46	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 (File No. 001-33303) filed January 23, 2019).

4.47	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 (File No. 001-33303) filed January 23, 2019).
4.48	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 (File No. 001-33303) filed January 23, 2019).
4.49	Supplemental Indenture dated July 19, 2019 to Indenture dated January 17, 2019, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.8 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed August 9, 2019 (File No. 001-33303)).
4.50	Indenture dated as of November 27, 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 (File No. 001-33303) filed December 3, 2019).
4.51	Registration Rights Agreement dated as of November 27, 2019 among the Issuers, the Guarantors and RBC Capital Markets, LLC, as representative of the several Initial Purchasers party thereto (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP's Current Report on Form 8-K (File No. 001-33303) filed December 3, 2019).
4.52	Specimen Unit Certificate for the Series A Preferred Units (attached as Exhibit B to the Second Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP and incorporated by reference to Exhibit 3.1 to Targa Resources Partners LP's Current Report on Form 8-K filed October 15, 2015 (File No. 001-33303)).
4.53*	Description of Securities Registered Under Section 12 of the Exchange Act.
10.1	Third Amendment and Restatement Agreement dated as of June 29, 2018, by and among Targa Resources Partners LP, Bank of America, N.A., and the other parties signatory thereto (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed July 3, 2018 (File No. 001-33303)).
10.2	First Amendment to Fourth Amended and Restated Credit Agreement, dated as of June 7, 2019, by and among Targa Resources Partners LP, Bank of America, N.A. and the other parties signatory thereto (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed June 11, 2019 (File No. 001-33303)).
10.3	Contribution, Conveyance and Assumption Agreement, dated February 14, 2007, by and among Targa Resources Partners LP, Targa Resources Operating LP, Targa Resources GP LLC, Targa Resources Operating GP LLC, Targa GP Inc., Targa LP Inc., Targa Regulated Holdings LLC, Targa North Texas GP LLC and Targa North Texas LP (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP's Current Report on Form 8-K filed February 16, 2007 (File No. 001-33303)).
10.4	Contribution, Conveyance and Assumption Agreement, dated October 24, 2007, by and among Targa Resources Partners LP, Targa Resources Holdings LP, Targa TX LLC, Targa TX PS LP, Targa LA LLC, Targa LA PS LP and Targa North Texas GP LLC (incorporated by reference to Exhibit 10.4 to Targa Resources Partners LP's Current Report on Form 8-K filed October 24, 2007 (File No. 001-33303)).
10.5	Contribution, Conveyance and Assumption Agreement, dated September 24, 2009, by and among Targa Resources Partners LP, Targa GP Inc., Targa LP Inc., Targa Resources Operating LP and Targa North Texas GP LLC (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed September 24, 2009 (File No. 001-33303)).
10.6	Contribution, Conveyance and Assumption Agreement, dated April 27, 2010, by and among Targa Resources Partners LP, Targa LP Inc., Targa Permian GP LLC, Targa Midstream Holdings LLC, Targa Resources Operating LP, Targa North Texas GP LLC and Targa Resources Texas GP LLC (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed April 29, 2010 (File No. 001-33303)).
10.7	Contribution, Conveyance and Assumption Agreement, dated August 25, 2010, by and among Targa Resources Partners LP, Targa Versado Holdings LP and Targa North Texas GP LLC (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed August 26, 2010 (File No. 001-33303)).

10.8	Contribution, Conveyance and Assumption Agreement, dated September 28, 2010, by and among Targa Resources Partners LP, Targa Versado Holdings LP and Targa North Texas GP LLC (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed October 4, 2010 (File No. 001-33303)).
10.9	Second Amended and Restated Omnibus Agreement, dated September 24, 2009, by and among Targa Resources Partners LP, Targa Resources, Inc., Targa Resources LLC and Targa Resources GP LLC (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP's Current Report on Form 8-K filed September 24, 2009 (File No. 001-33303)).
10.10	First Amendment to Second Amended and Restated Omnibus Agreement, dated April 27, 2010, by and among Targa Resources Partners LP, Targa Resources, Inc., Targa Resources LLC and Targa Resources GP LLC (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP's Current Report on Form 8-K filed April 29, 2010 (File No. 001-33303)).
10.11	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 (File No. 001-33303) filed January 15, 2019).
10.12	Purchase Agreement dated as of November 13, 2019, among the Issuers, the Guarantors and RBC Capital Markets, LLC, as representative of the several initial purchasers (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K (File No. 001-33303) filed November 19, 2019).
10.13	Receivables Purchase Agreement, dated January 10, 2013, by and among Targa Receivables LLC, the Partnership, as initial Servicer, the various conduit purchasers from time to time party thereto, the various committed purchasers from time to time party thereto, the various purchaser agents from time to time party thereto, the various LC participants from time to time party thereto and PNC Bank, National Association as Administrator and LC Bank (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed January 14, 2013 (File No. 001-33303)).
10.14	Purchase and Sale Agreement, dated January 10, 2013, between the originators from time to time party thereto as Originators and Targa Receivables LLC (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP's Current Report on Form 8-K filed January 14, 2013 (File No. 001-33303)).
10.15	Second Amendment to Receivables Purchase Agreement, dated December 13, 2013, by and among Targa Receivables LLC, as seller, the Partnership, as servicer, the various conduit purchasers, committed purchasers, purchaser agents and LC participants party thereto and PNC Bank, National Association, as administrator and LC Bank (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed December 17, 2013 (File No. 001-33303)).
10.16	Fourth Amendment to Receivables Purchase Agreement, dated December 11, 2015, by and among Targa Receivables LLC, as seller, the Partnership, as servicer, the various conduit purchasers, committed purchasers, purchaser agents and LC participants party thereto and PNC Bank, National Association, as administrator and LC Bank (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed December 15, 2015 (File No. 001-33303)).
10.17	Fifth Amendment to Receivables Purchase Agreement, dated December 9, 2016, by and among Targa Receivables LLC, as seller, the Partnership, as servicer, the various conduit purchasers, committed purchasers, purchaser agents and LC participants party thereto and PNC Bank, National Association, as administrator and LC Bank (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed January 6, 2017 (File No. 001-33303)).
10.18	Seventh Amendment to Receivables Purchase Agreement, dated December 7, 2018, by and among Targa Receivables LLC, as seller, the Partnership, as servicer, the various conduit purchasers, committed purchasers, purchaser agents and LC participants party thereto and PNC Bank, National Association, as administrator and LC Bank (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed December 10, 2018 (File No. 001-33303)).
10.19	Eighth Amendment to Receivables Purchase Agreement, dated December 6, 2019, by and among Targa Receivables LLC, as seller, the Partnership, as servicer, the various conduit purchasers, committed purchasers, purchaser agents and LC participants party thereto and PNC Bank, National Association, as administrator and LC Bank. (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed on December 10, 2019 (File No. 001-33303)).

10.20	Commitment Increase Request, dated February 23, 2017, by and among Targa Receivables LLC, as seller, the Partnership, as servicer, and PNC Bank, National Association, as administrator, purchaser agent and LC Bank (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed February 24, 2017 (File No. 001-33303)).
10.21+	Targa Resources Corp. 2019 Annual Incentive Compensation Plan (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed January 22, 2019 (File No. 001-33303)).
10.22+	Targa Resources Corp. 2020 Annual Incentive Compensation Plan (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed January 23, 2020 (File No. 001-33303)).
10.23+	Targa Resources Executive Officer Change In Control Severance Program (incorporated by reference to Exhibit 10.3 to Targa Resources Partners LP's Current Report on Form 8-K filed January 19, 2012 ((File No. 001-33303)).
10.24+	First Amendment to the Targa Resources Executive Officer Change in Control Severance Program, dated December 3, 2015 (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed December 8, 2015 ((File No. 001-33303)).
10.25+	Form of Indemnification Agreement between Targa Resources Investments Inc. and each of the directors and officers thereof (incorporated by reference to Exhibit 10.4 to Targa Resources Corp.'s Registration Statement on Form S-1/A filed November 8, 2010 (File No. 333-169277)).
10.26+	Targa Resources Partners LP Indemnification Agreement for Robert B. Evans dated February 14, 2007 (incorporated by reference to Exhibit 10.11 to Targa Resources Partners LP's Annual Report on Form 10-K filed April 2, 2007 (File No. 001-33303)).
10.27+	Targa Resources Partners LP Indemnification Agreement for Barry R. Pearl dated February 14, 2007 (incorporated by reference to Exhibit 10.12 to Targa Resources Partners LP's Annual Report on Form 10-K filed April 2, 2007 (File No. 001-33303)).
10.28+	Indemnification Agreement by and between Targa Resources Corp. and Laura C. Fulton, dated February 26, 2013 (incorporated by reference to Exhibit 10.1 to Targa Resources Corp.'s Current Report on Form 8-K filed March 1, 2013 (File No. 001-34991)).
10.29+	Indemnification Agreement by and between Targa Resources Corp. and Waters S. Davis, IV, dated July 23, 2015 (incorporated by reference to Exhibit 10.1 to Targa Resources Corp.'s Current Report on Form 8-K filed July 24, 2015 (File No. 001-34991)).
10.30+	Indemnification Agreement by and between Targa Resources Corp. and D. Scott Pryor, dated November 12, 2015 (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed November 16, 2015 (File No. 001-33303)).
10.31+	Indemnification Agreement by and between Targa Resources Corp. and Patrick J. McDonie, dated November 12, 2015 (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP's Current Report on Form 8-K filed November 16, 2015 (File No. 001-33303)).
10.32+	Indemnification Agreement by and between Targa Resources Corp. and Clark White, dated November 12, 2015 (incorporated by reference to Exhibit 10.4 to Targa Resources Partners LP's Current Report on Form 8-K filed November 16, 2015 (File No. 001-33303)).
10.33+	Indemnification Agreement by and between Targa Resources Corp. and Robert Muraro, dated February 22, 2017 (incorporated by reference to Exhibit 10.1 to Targa Resources Corp.'s Current Report on Form 8-K filed February 27, 2017 (File No. 001-34991)).
10.34+	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 Partners LP's Current Report on Form 8-K filed March 5, 2019 (File No. 001-33303)).
10.35	Gas Gathering and Purchase Agreement by and between Burlington Resources Oil & Gas Company LP, Burlington Resources Trading Inc. and Targa Midstream Services Limited Partnership (portions of this exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment) (incorporated by reference to Exhibit 10.5 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed February 8, 2007 (File No. 333-138747)).

21.1*	List of Subsidiaries of Targa Resources Partners LP.
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.
31.2*	Certification of Chief Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.
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.
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.
99.1***	First Amendment to Membership Interest Purchase and Sale Agreement, dated December 20, 2012, by and among the Partnership, Saddle Butte Pipeline LLC, Saddle Butte Fort Berthold Gathering, LLC and Saddle Butte Assets, LLC (incorporated by reference to Exhibit 99.1 to Targa Resources Partners LP's Current Report on Form 8-K filed January 4, 2013 (File No. 001-33303)).
101.INS*	Inline XBRL Instance Document
101.SCH*	Inline XBRL Taxonomy Extension Schema Document
101.CAL*	Inline XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	Inline XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	Inline XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	Inline XBRL Taxonomy Extension Presentation Linkbase Document
104	Cover Page Interactive Data File (embedded within the Inline XBRL document).

* Filed herewith
** Furnished herewith
*** Pursuant to Item 601(b)(2) of Regulation S-K, the Partnership agrees to furnish supplementally a copy of any omitted exhibit or Schedule to the SEC upon request
\+ Management contract or compensatory plan or arrangement

Item 16. Form 10-K Summary

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Targa Resources Partners LP
(Registrant)

By: Targa Resources GP LLC,
its general partner

Date: February 20, 2020

By: */s/ Jennifer R. Kneale*
Jennifer R. Kneale
Chief Financial Officer
(Principal Financial Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on February 20, 2020.

Signature	Title (Position with Targa Resources GP LLC)
/s/ Joe Bob Perkins Joe Bob Perkins	Chief Executive Officer and Director (Principal Executive Officer)
/s/ Jennifer R. Kneale Jennifer R. Kneale	Chief Financial Officer (Principal Financial Officer)
/s/ Julie H. Boushka Julie H. Boushka	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)
/s/ James W. Whalen James W. Whalen	Executive Chairman of the Board and Director
/s/ Charles R. Crisp Charles R. Crisp	Director
/s/ Waters S. Davis, IV Waters S. Davis, IV	Director
/s/ Robert B. Evans Robert B. Evans	Director
/s/ Laura C. Fulton Laura C. Fulton	Director
/s/ Ershel C. Redd Jr. Ershel C. Redd Jr.	Director
/s/ Chris Tong Chris Tong	Director
/s/ Rene R. Joyce Rene R. Joyce	Director
/s/ Beth A. Bowman Beth A. Bowman	Director

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

TARGA RESOURCES PARTNERS LP AUDITED CONSOLIDATED FINANCIAL STATEMENTS

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control over financial reporting is a process designed 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.

Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal control over financial reporting is a process that involves human diligence and compliance and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting also can be circumvented by collusion or improper management override. Because of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis by internal control over financial reporting. However, these inherent limitations are known features of the financial reporting process. Therefore, it is possible to design into the process safeguards to reduce, though not eliminate, this risk.

Management has used the framework set forth in the report entitled "Internal Control—Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") in 2013 to evaluate the effectiveness of the internal control over financial reporting. Based on that evaluation, management has concluded that the internal control over financial reporting was effective as of December 31, 2019.

The effectiveness of our internal control over financial reporting as of December 31, 2019 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears on page F-3.

/s/ Joe Bob Perkins
Joe Bob Perkins
Chief Executive Officer
(Principal Executive Officer)

/s/ Jennifer R. Kneale
Jennifer R. Kneale
Chief Financial Officer
(Principal Financial Officer)

Report of Independent Registered Public Accounting Firm

To the Board of Directors of Targa Resources GP LLC and the Partners of Targa Resources Partners LP

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Targa Resources Partners LP and its subsidiaries (the “Partnership”) as of December 31, 2019 and 2018, and the related consolidated statements of operations, of comprehensive income (loss), of changes in owners’ equity, and of cash flows for each of the three years in the period ended December 31, 2019, including the related notes (collectively referred to as the “consolidated financial statements”). We also have audited the Partnership’s internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Partnership as of December 31, 2019, and 2018**,** and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Partnership’s management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on the Partnership’s consolidated financial statements and on the Partnership’s internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company’s internal control over financial reporting is a process designed 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. A company’s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Houston, Texas
February 20, 2020

We have served as the Partnership’s auditor since 2005.

PART I – FINANCIAL INFORMATION

Item 1. Financial Statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED BALANCE SHEETS

			December 31, 2019	December 31, 2018
			(In millions)	
ASSETS				
Current assets:				
Cash and cash equivalents			$ 291.1	$ 203.3
Trade receivables, net of allowances of $0.0 and $0.1 million at December 31, 2019 and December 31, 2018			855.2	864.4
Inventories			161.5	164.7
Assets from risk management activities			103.3	115.3
Other current assets			54.2	32.2
Held for sale assets (see Note 4)			137.7	—
Total current assets			1,603.0	1,379.9
Property, plant and equipment			19,870.6	17,213.8
Accumulated depreciation and amortization			(5,321.6)	(4,285.5)
Property, plant and equipment, net			14,549.0	12,928.3
Intangible assets, net			1,735.0	1,983.2
Goodwill, net			45.2	46.6
Long-term assets from risk management activities			35.5	34.1
Investments in unconsolidated affiliates			738.7	490.5
Other long-term assets			38.1	27.5
Total assets			$ 18,744.5	$ 16,890.1
LIABILITIES AND OWNERS' EQUITY				
Current liabilities:				
Accounts payable and accrued liabilities			$ 1,283.7	$ 1,636.9
Accounts payable to Targa Resources Corp.			193.8	187.4
Liabilities from risk management activities			104.1	33.6
Current debt obligations			382.2	1,027.9
Held for sale liabilities (see Note 4)			6.4	—
Total current liabilities			1,970.2	2,885.8
Long-term debt			7,005.2	5,197.4
Long-term liabilities from risk management activities			40.8	3.1
Deferred income taxes, net			23.0	23.9
Other long-term liabilities			260.0	233.8
Contingencies (see Note 18)				
Owners' equity:				
Series A preferred limited partners	Issued	Outstanding	120.6	120.6
December 31, 2019	5,000,000	5,000,000		
December 31, 2018	5,000,000	5,000,000		
Common limited partners	Issued	Outstanding	5,022.7	6,227.2
December 31, 2019	275,168,410	275,168,410		
December 31, 2018	275,168,410	275,168,410		
General partner	Issued	Outstanding	778.0	802.6
December 31, 2019	5,629,136	5,629,136		
December 31, 2018	5,629,136	5,629,136		
Accumulated other comprehensive income (loss)			122.5	124.9
			6,043.8	7,275.3
Noncontrolling interests			3,401.5	1,270.8
Total owners' equity			9,445.3	8,546.1
Total liabilities and owners' equity			$ 18,744.5	$ 16,890.1

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2019	2018	2017
	(In millions)		
Revenues:			
Sales of commodities	$ 7,393.8	$ 9,278.7	$ 7,751.1
Fees from midstream services	1,277.3	1,205.3	1,063.8
Total revenues	8,671.1	10,484.0	8,814.9
Costs and expenses:			
Product purchases	6,118.5	8,238.2	6,906.1
Operating expenses	792.8	722.0	622.8
Depreciation and amortization expense	971.7	815.9	809.5
General and administrative expense	267.5	240.8	190.5
Impairment of property, plant and equipment	243.2	—	378.0
Impairment of goodwill	—	210.0	—
Other operating (income) expense	71.3	3.5	17.4
Income (loss) from operations	206.1	253.6	(109.4)
Other income (expense):			
Interest expense, net	(320.8)	(170.0)	(217.8)
Equity earnings (loss)	39.0	7.3	(17.0)
Gain (loss) from financing activities	(1.4)	(1.3)	(10.9)
Gain (loss) from sale of equity-method investment	69.3	—	—
Change in contingent considerations	(8.7)	8.8	99.6
Other, net	—	0.1	(2.5)
Income (loss) before income taxes	(16.5)	98.5	(258.0)
Income tax (expense) benefit	0.9	0.1	7.4
Net income (loss)	(15.6)	98.6	(250.6)
Less: Net income (loss) attributable to noncontrolling interests	239.1	47.6	38.9
Net income (loss) attributable to Targa Resources Partners LP	$ (254.7)	$ 51.0	$ (289.5)
Net income attributable to preferred limited partners	$ 11.3	$ 11.3	$ 11.3
Net income (loss) attributable to general partner	(5.3)	0.8	(6.0)
Net income (loss) attributable to common limited partners	(260.7)	38.9	(294.8)
Net income (loss) attributable to Targa Resources Partners LP	$ (254.7)	$ 51.0	$ (289.5)

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Year Ended December 31,		
	2019	2018	2017
	(In millions)		
Net income (loss)	$ (15.6)	$ 98.6	$ (250.6)
Other comprehensive income (loss):			
Commodity hedging contracts:			
Change in fair value	135.6	132.5	(28.8)
Settlements reclassified to revenues	(138.0)	38.4	44.6
Other comprehensive income (loss)	(2.4)	170.9	15.8
Comprehensive income (loss)	(18.0)	269.5	(234.8)
Less: Comprehensive income (loss) attributable to noncontrolling interests	239.1	47.6	38.9
Comprehensive income (loss) attributable to Targa Resources Partners LP	$ (257.1)	$ 221.9	$ (273.7)

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF CHANGES IN OWNERS' EQUITY

	Limited Partner		Limited Partner		General Partner		Accumulated Other Comprehensive Income (Loss)	Non-controlling Interests	Total
	Preferred	Amount	Common	Amount	Units	Amount			
	(In millions, except units in thousands)								
Balance, December 31, 2016	5,000	$ 120.6	275,168	$ 5,939.9	5,629	$ 796.7	$ (61.8)	$ 355.2	$ 7,150.6
Contributions from Targa Resources Corp.	—	—	—	1,685.5	—	34.5	—	—	1,720.0
Purchase of noncontrolling interests in subsidiaries, net	—	—	—	—	—	—	—	(12.5)	(12.5)
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(48.1)	(48.1)
Contributions from noncontrolling interests	—	—	—	—	—	—	—	141.6	141.6
Other comprehensive income (loss)	—	—	—	—	—	—	15.8	—	15.8
Net income (loss)	—	11.3	—	(294.8)	—	(6.0)	—	38.9	(250.6)
Distributions	—	(11.3)	—	(830.3)	—	(17.0)	—	—	(858.6)
Balance, December 31, 2017	5,000	$ 120.6	275,168	$ 6,500.3	5,629	$ 808.2	$ (46.0)	$ 475.1	$ 7,858.2
Contributions from Targa Resources Corp.	—	—	—	588.1	—	12.0	—	—	600.1
Acquisition of related party	—	—	—	—	—	—	—	1.1	1.1
Purchase of noncontrolling interests in subsidiaries, net	—	—	—	—	—	—	—	(0.1)	(0.1)
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(70.8)	(70.8)
Contributions from noncontrolling interests	—	—	—	—	—	—	—	817.9	817.9
Other comprehensive income (loss)	—	—	—	—	—	—	170.9	—	170.9
Net income (loss)	—	11.3	—	38.9	—	0.8	—	47.6	98.6
Distributions	—	(11.3)	—	(900.1)	—	(18.4)	—	—	(929.8)
Balance, December 31, 2018	5,000	$ 120.6	275,168	$ 6,227.2	5,629	$ 802.6	$ 124.9	$ 1,270.8	$ 8,546.1
Contributions from Targa Resources Corp.	—	—	—	196.0	—	4.0	—	—	200.0
Sale of ownership interests in subsidiaries	—	—	—	(10.5)	—	(0.2)	—	1,619.7	1,609.0
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(283.4)	(283.4)
Contributions from noncontrolling interests	—	—	—	—	—	—	—	555.3	555.3
Other comprehensive income (loss)	—	—	—	—	—	—	(2.4)	—	(2.4)
Net income (loss)	—	11.3	—	(260.7)	—	(5.3)	—	239.1	(15.6)
Distributions	—	(11.3)	—	(1,129.3)	—	(23.1)	—	—	(1,163.7)
Balance, December 31, 2019	5,000	$ 120.6	275,168	$ 5,022.7	5,629	$ 778.0	$ 122.5	$ 3,401.5	$ 9,445.3

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2019	2018	2017
		(In millions)	
Cash flows from operating activities			
Net income (loss)	$ (15.6)	$ 98.6	$ (250.6)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Amortization in interest expense	9.2	9.1	9.3
Depreciation and amortization expense	971.7	815.9	809.5
Impairment of property, plant and equipment	243.2	—	378.0
Impairment of goodwill	—	210.0	—
Accretion of asset retirement obligations	4.7	3.7	3.9
Increase (decrease) in redemption value of mandatorily redeemable preferred interests	—	(72.1)	3.3
Deferred income tax expense (benefit)	(0.9)	(0.1)	(2.9)
Equity (earnings) loss of unconsolidated affiliates	(39.0)	(7.3)	17.0
Distributions of earnings received from unconsolidated affiliates	49.6	20.8	12.5
Risk management activities	112.8	9.8	10.0
(Gain) loss on sale or disposition of business and assets	71.1	(0.1)	15.9
(Gain) loss from financing activities	1.4	1.3	10.9
(Gain) loss from sale of equity-method investment	(69.3)	—	—
Change in contingent considerations	8.7	(8.8)	(99.6)
Changes in operating assets and liabilities, net of business acquisitions:			
Receivables and other assets	(11.9)	(9.8)	(177.7)
Inventories	(45.0)	(13.9)	(73.2)
Accounts payable and other liabilities	72.3	156.5	191.3
Net cash provided by operating activities	1,363.0	1,213.6	857.6
Cash flows from investing activities			
Outlays for property, plant and equipment	(2,877.3)	(3,114.0)	(1,297.5)
Outlays for business acquisition, net of cash acquired	—	—	(570.8)
Proceeds from sale of business and assets	14.8	256.9	2.7
Investments in unconsolidated affiliates	(266.8)	(282.0)	(9.5)
Proceeds from sale of equity-method investment	70.3	—	—
Return of capital from unconsolidated affiliates	3.5	5.5	0.2
Other, net	(15.9)	(12.5)	(17.8)
Net cash used in investing activities	(3,071.4)	(3,146.1)	(1,892.7)
Cash flows from financing activities			
Debt obligations:			
Proceeds from borrowings under credit facility	2,650.0	1,870.0	1,736.0
Repayments of credit facility	(3,350.0)	(1,190.0)	(1,866.0)
Proceeds from borrowings under accounts receivable securitization facility	944.2	546.6	666.6
Repayments of accounts receivable securitization facility	(854.2)	(616.6)	(591.6)
Proceeds from issuance of senior notes	2,500.0	1,000.0	750.0
Redemption of senior notes	(749.4)	—	(538.1)
Principal payments of finance leases	(11.5)	—	—
Costs incurred in connection with financing arrangements	(35.4)	(16.2)	(7.5)
Payment of contingent consideration	(317.1)	—	—
Purchase of noncontrolling interests in subsidiary	—	(0.1)	(12.5)
Sale of ownership interests in subsidiaries	1,619.7	—	—
Contributions from general partner	4.0	12.0	34.5
Contributions from TRC	196.0	588.1	1,685.5
Contributions from noncontrolling interests	555.3	817.9	141.6
Distributions to noncontrolling interests	(191.7)	(70.8)	(48.1)
Distributions to unitholders	(1,163.7)	(929.8)	(858.6)
Net cash provided by financing activities	1,796.2	2,011.1	1,091.8
Net change in cash and cash equivalents	87.8	78.6	56.7
Cash and cash equivalents, beginning of period	203.3	124.7	68.0
Cash and cash equivalents, end of period	$ 291.1	$ 203.3	$ 124.7

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 Partners LP is a Delaware limited partnership formed in October 2006 by our parent, Targa Resources Corp. ("Targa" or "TRC" or the "Company" or "Parent"). In this Annual Report, unless the context requires otherwise, references to "we," "us," "our," "TRP," or the "Partnership" are intended to mean the business and operations of Targa Resources Partners LP and its consolidated subsidiaries.

Our common units are wholly owned by TRC and no longer publicly traded as a result of TRC's acquisition of our outstanding common units that it and its subsidiaries did not already own in 2016.

The 5,000,000 9.00% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Preferred Units") that were issued in October 2015 remain outstanding as limited partner interests in us and continue to trade on the NYSE under the symbol "NGLS/PA."

Our Operations

We are 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 25 – Segment Information for certain financial information regarding our business segments.

The employees supporting our operations are employed by Targa. Our consolidated financial statements include the direct costs of Targa employees deployed to our operating segments, as well as an allocation of costs associated with our usage of Targa's centralized general and administrative services.

Note 2 — Basis of Presentation

These accompanying financial statements and related notes present our consolidated financial position as of December 31, 2019 and 2018, and the results of operations, comprehensive income, cash flows, and changes in owners' equity for the years ended December 31, 2019, 2018 and 2017.

We have prepared these consolidated financial statements in accordance with GAAP. 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.

Note 3 — Significant Accounting Policies

Consolidation Policy

Our consolidated financial statements include the accounts of all entities that we control and our proportionate interest in the accounts of certain gas gathering and processing facilities in which we own an undivided interest and are responsible for our proportionate share of the costs and expenses of the facilities. Third party ownership interests in our controlled subsidiaries are presented as noncontrolling interests within the equity section of our Consolidated Balance Sheets. In our Consolidated Statements of Operations and Consolidated Statements of Comprehensive Income, noncontrolling interests reflects the attribution of results to third-party investors. All intercompany balances and transactions have been eliminated in consolidation.

We apply the equity method of accounting to investments over which we exercise significant influence over the operating and financial policies of our investee, but do not exercise control. We evaluate our equity investments for impairment when evidence indicates the carrying amount of our investment is no longer recoverable. Evidence of a loss in value might include, but would not necessarily be limited to, absence of an ability to recover the carrying amount of the investment or inability of the equity method investee to sustain an earnings capacity that would justify the carrying amount of the investment. When the estimated fair value of an equity investment is less than its carrying value and the loss in value is determined to be other than temporary, we recognize the excess of the carrying value over the estimated fair value as an impairment loss within equity earnings (loss) in our Consolidated Statements of Operations.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in these financial statements and accompanying notes. Estimates and judgments are based on information available at the time such estimates and judgments are made. Changes in facts and circumstances may result in revised estimates and actual results could differ materially from those estimates. Estimates and judgments are used in, among other things, (1) estimating unbilled revenues, product purchases and operating and general and administrative cost accruals, (2) developing fair value assumptions, including estimates of future cash flows and discount rates, (3) analyzing long-lived assets for possible impairment, (4) estimating the useful lives of assets, (5) estimating contingencies, guarantees and indemnifications and (6) estimating redemption value of mandatorily redeemable preferred interests.

Cash and Cash Equivalents

Cash and cash equivalents include all cash on hand, demand deposits, and short-term, highly liquid investments that are readily convertible into cash, and have original maturities of three months or less.

Allowance for Doubtful Accounts

Estimated losses on accounts receivable are provided through an allowance for doubtful accounts. In evaluating the adequacy of the allowance, we make judgments regarding each party’s ability and history of making required payments, economic events and other factors. We assess the need for adjustments to our allowance when the financial condition of any party changes or additional information becomes available.

Inventories

Our inventories consist primarily of NGL product inventories, which are valued at the lower of cost or net realizable value, using the average cost method. Most NGL product inventories turn over monthly, but some inventory, primarily propane, is acquired and held during the year to meet anticipated heating season requirements of our customers. Commodity inventories that are not physically or contractually available for sale under normal operations (“deadstock”) are included in Property, Plant and Equipment.

Product Exchanges

Exchanges of NGL products are executed to satisfy timing and logistical needs of the exchange parties. Volumes received and delivered under exchange agreements are recorded as inventory. If the locations of receipt and delivery are in different markets, an exchange differential may be billed or owed. The exchange differential is recorded as either accounts receivable or accrued liabilities.

Gas Processing Imbalances

Quantities of natural gas and/or NGLs over-delivered or under-delivered, related to certain gas plant operational balancing agreements, are recorded monthly as inventory or as a payable using the weighted average price at the time the imbalance was created. Inventory imbalances receivable are valued at the lower of cost or net realizable value using the average cost method; inventory imbalances payable are valued at replacement cost. These imbalances are settled either by current cash-out settlements or by adjusting future receipts or deliveries of natural gas or NGLs.

Derivative Instruments

We utilize derivative instruments to manage the volatility of our cash flows due to fluctuating energy commodity prices. For balance sheet classification purposes, we analyze the fair values of the derivative instruments on a contract by contract basis and report the related fair values and any related collateral by counterparty on a gross basis. Cash flows from derivative instruments designated as hedges are recognized in the same financial statement line item as the cash flows from the respective item being hedged.

We formally document all relationships between hedging instruments and hedged items, as well as its risk management objectives and strategy for undertaking the hedge. This documentation includes the specific identification of the hedging instrument and the hedged item, the nature of the risk being hedged and the manner in which the hedging instrument's effectiveness will be assessed. At the inception of the hedge and on an ongoing basis, we assess whether the derivatives used in hedging transactions are highly effective in achieving the offset of changes in cash flows attributable to the hedged risk.

We record all derivative instruments at fair value with the exception of those that we apply the normal purchases and normal sales election.

The table below summarizes the accounting treatment for our derivative instruments, and the impact on our consolidated financial statements:

	Recognition and Measurement	
Derivative Treatment	**Balance Sheet**	**Income Statement**
Normal Purchases and Normal Sales	Fair value not recorded	Earnings recognized when volumes are physically delivered or received
Mark-to-Market	Recorded at fair value	Change in fair value recognized currently in earnings
Cash Flow Hedge	Recorded at fair value with changes in fair value deferred in Accumulated Other Comprehensive Income ("AOCI")	The gain/loss on the derivative instrument is reclassified out of AOCI into earnings when the forecasted transaction occurs

We will discontinue hedge accounting on a prospective basis when a hedge instrument is terminated, ceases to be highly effective or the forecasted transaction is no longer probable to occur. Gains and losses deferred in AOCI related to cash flow hedges for which hedge accounting has been discontinued remain deferred until the forecasted transaction occurs. If it is probable that a hedged forecasted transaction will not occur, deferred gains or losses on the hedging instrument are reclassified to earnings immediately.

Property, Plant and Equipment

Property, plant and equipment is recorded at acquisition cost less accumulated depreciation. Depreciation is computed using the straight-line method over the estimated useful lives of the assets. The determination of the useful lives of property, plant and equipment requires us to make various assumptions, including our expected use of the asset and the supply of and demand for hydrocarbons in the markets served, normal wear and tear of the facilities, and the extent and frequency of maintenance programs. Upon disposition or retirement of property, plant and equipment, any gain or loss is recorded to operations.

Expenditures for routine maintenance and repairs are expensed as incurred. Expenditures to refurbish an asset that increases its existing service potential or prevents environmental contamination are capitalized and depreciated over the remaining useful life of the asset or major asset component. Certain costs directly related to the construction of assets, including internal labor costs, interest and engineering costs, are capitalized.

Impairment of Long-Lived Assets

We evaluate long-lived assets for impairment when events or changes in circumstances indicate our carrying amount of an asset may not be recoverable. Asset recoverability is measured by comparing the carrying value of the asset or asset group with its expected future pre-tax undiscounted cash flows. Individual assets are grouped at the lowest level for which the related identifiable cash flows are largely independent of the cash flows of other assets and liabilities. These cash flow estimates require us to make judgments and assumptions related to operating and cash flow results, economic obsolescence, the business climate, contractual, legal and other factors.

If the carrying amount exceeds the expected future undiscounted cash flows, we recognize an impairment equal to the excess of net book value over fair value as determined by quoted market prices in active markets or present value techniques if quotes are unavailable. The determination of the fair value using present value techniques requires us to make projections and assumptions regarding the probability of a range of outcomes and the rates of interest used in the present value calculations. Any changes we make to these projections and assumptions could result in significant revisions to our evaluation of recoverability of our long-lived assets and the recognition of additional impairments.

Goodwill

Goodwill is a residual intangible asset that results when the cost of an acquisition exceeds the fair value of the net identifiable assets of the acquired business. Goodwill is not subject to amortization but is tested for impairment at least annually. This test requires us to attribute goodwill to an appropriate reporting unit, which is an operating segment or one level below an operating segment (also known as a component). We evaluate goodwill for impairment on November 30 of each year, or whenever impairment indicators are present. Prior to us conducting the goodwill impairment test, we complete a review of the carrying values of our long-lived assets, including property, plant and equipment and other intangible assets. If it is determined that the carrying values are not recoverable, we reduce the carrying values of the long-lived assets pursuant to our policy on property, plant and equipment.

As part of our goodwill impairment test, we may first assess qualitative factors to determine if the quantitative goodwill impairment test is necessary. If we choose to bypass this qualitative assessment or determine that a goodwill impairment test is required, our annual goodwill impairment test is performed by comparing the fair value of a reporting unit with its carrying amount (including attributed goodwill). We recognize an impairment loss in our Consolidated Statements of Operations and a corresponding reduction of goodwill on our Consolidated Balance Sheets for the amount by which the carrying amount exceeds the reporting unit’s fair value. The goodwill impairment loss will not exceed the total amount of goodwill allocated to that reporting unit. Additionally, when measuring goodwill, we consider income tax effects from any tax deductible goodwill on the carrying amount of the reporting unit, if applicable.

Intangible Assets

Our intangible assets include producer dedications under long-term contracts and customer relationships associated with business and asset acquisitions. The fair value of these acquired intangible assets was determined at the date of acquisition based on the present value of estimated future cash flows. We amortize the costs of our assets in a manner that closely resembles the expected benefit pattern of the intangible assets or on a straight-line basis, where such pattern is not readily determinable, over the periods in which we benefit from services provided to customers.

Asset Retirement Obligations

Asset retirement obligations (“AROs”) are legal obligations associated with the retirement of tangible long-lived assets that result from their acquisition, construction, development and/or normal operation. We record a liability and increase the basis in the underlying asset for the present value of each expected asset retirement obligation (“ARO”) when there is a legal obligation to settle under existing or enacted law, statute, written or oral contract or by legal construction.

Our obligations are estimated based on discounted cash flow estimates. Over time, the ARO liability is accreted to its present value as a period cost and the capitalized amount is depreciated over the asset’s respective useful life. At least annually, we review the projected timing and amount of asset retirement obligations and reflect revisions as an increase or decrease in the carrying amount of the liability and the basis in the underlying asset. Upon settlement, we will recognize any difference between the recorded amount and the actual settlement cost as a gain or loss.

Debt Issuance Costs

Costs incurred in connection with the issuance of long-term debt and any original issue discount or premium are deferred and charged to interest expense over the term of the related debt. Debt issuance costs related to revolving credit facilities are presented as other long-term assets, and debt issuance costs related to long-term debt obligations with scheduled maturities are reflected as a deduction to the carrying amount of long-term debt on the Consolidated Balance Sheets. Gains or losses on debt repurchases, redemptions and debt extinguishments include any associated unamortized debt issuance costs.

Accounts Receivable Securitization Facility

Proceeds from the sale or contribution of certain receivables under the accounts receivable securitization facility (the “Securitization Facility”) are treated as collateralized borrowings in our financial statements. Proceeds and repayments under the Securitization Facility are reflected as cash flows from financing activities in our Consolidated Statements of Cash Flows.

Environmental Liabilities and Other Loss Contingencies

We accrue a liability for loss contingencies, including environmental remediation costs arising from claims, assessments, litigation, fines, penalties and other sources, when the loss is probable and reasonably estimable.

Income Taxes

We generally are not subject to federal income taxes. For federal income tax purposes, our earnings or losses are included in the tax returns of our separate partners. The taxable income or loss passed through to our partners may vary substantially from the net income or net loss we report in the Consolidated Statements of Operations.

As part of the APL merger, we acquired TPL Arkoma, Inc. a corporate subsidiary subject to federal and state income tax. The Partnership's corporate subsidiary accounts for income taxes using the asset and liability method and provides deferred income taxes for all significant temporary differences.

As part of the process of preparing our consolidated financial statements, we are required to estimate our income taxes for our taxable corporate subsidiary. This process involves estimating our actual current tax payable and related tax expense together with assessing temporary differences resulting from differing treatment of certain items, such as depreciation, for tax and accounting purposes. These differences can result in deferred tax assets and liabilities, which are included within our Consolidated Balance Sheets.

We must then assess the likelihood that our deferred tax assets will be recovered from future taxable income. If we believe that it is more likely than not (a likelihood of more than 50%) that some portion or all of the deferred tax assets will not be realized, we establish a valuation allowance. Any change in the valuation allowance would impact our income tax provision and net income in the period in which such a determination is made. We consider all available evidence to determine whether, based on the weight of the evidence, a valuation allowance is needed. Evidence used includes information about our current financial position and our results of operations for the current and preceding years, as well as all currently available information about future years, including our anticipated future performance, the reversal of deferred tax liabilities and tax planning strategies.

The effective tax rate differs from the statutory rate due primarily to Partnership earnings that are generally not subject to federal and state income taxes at the Partnership level. We are also subject to the Texas margin tax, consisting generally of a 0.75% tax on the amount by which total revenues exceed cost of goods sold, as apportioned to Texas. See Note 22 – Income Tax for discussion of the Partnership's federal and state income tax expense (benefits) of its taxable subsidiary as well as the Partnership's net deferred income tax assets (liabilities).

Mandatorily Redeemable Preferred Interests

Mandatorily redeemable preferred interests are included in other long-term liabilities on our Consolidated Balance Sheets. Mandatorily redeemable preferred interests with multiple or indeterminate redemption dates are reported at their estimated redemption value as of the reporting date. This point-in-time value does not represent the amount that ultimately would be redeemed in the future. Changes in the redemption value are included in interest expense, net in our Consolidated Statements of Operations.

Comprehensive Income

Comprehensive income includes net income and other comprehensive income ("OCI"), which includes changes in the fair value of derivative instruments that are designated as cash flow hedges.

Revenue Recognition

Our operating revenues are primarily derived from the following activities:

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

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

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

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

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

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

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

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

We have certain long-term contractual arrangements under which we have received consideration, but for which all conditions for revenue recognition have not been met. These arrangements result in deferred revenue, which will be recognized over the periods that performance will be provided.

Significant Judgments

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

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

Contract Assets

We classify our contract assets as receivables because we generally have an unconditional right to payment for the commodities sold or services performed at the end of reporting period.

Unit-Based and Share-Based Compensation

Prior to the TRC/TRP Merger, we awarded unit-based compensation to employees of Targa and to directors and non-management directors of our General Partner in the form of restricted common units and performance units. We withheld units to satisfy employees' tax withholding obligations on vested awards. The withheld shares were recorded as treasury units at cost. In connection with the TRC/TRP Merger, the unit-based compensation was converted to comparable share-based TRC awards and share-based compensation is now awarded in the form of TRC restricted stock, and TRC restricted stock units. Compensation expense on awards that qualify as equity arrangements are measured by the fair value of the award as determined at the date of grant. Compensation expense on awards that qualify as liability arrangements is initially measured by the fair value of the award at the date of grant, and re-measured subsequently at each reporting date through the settlement period. Compensation expense is allocated to us from TRC and recognized in general and administrative expense over the requisite service period of each award.

Recent Accounting Pronouncements

Recently adopted accounting pronouncements

Leases

In February 2016, the Financial Accounting Standards Board 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 $64.2 million (net of $0.4 million of lease incentives/deferred rent) and lease liability of $64.6 million. Other practical expedients we elected include:

- The package for transition relief, which among other things, allows us to carry forward our 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 only new or modified land easements on or after January 1, 2019 under Topic 842;
- The short-term lease election, which allows us to elect not to record leases with an initial term of twelve months or less, for all asset classes;
- 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 12 – Leases for additional details.

Note 4 – Joint Ventures, Acquisitions and Divestitures

Joint Ventures

Grand Prix Joint Venture

In May 2017, we announced plans to construct the Grand Prix pipeline ("Grand Prix"), a new common carrier NGL pipeline. Grand Prix transports NGLs from the Permian Basin, North Texas, and Southern Oklahoma to our fractionation and storage complex in the NGL market hub at Mont Belvieu, Texas. Grand Prix is supported by our volumes and other third-party customer volume commitments.

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

Grand Prix is comprised of three primary segments:

- Permian Basin Segment – Connects our Gathering and Processing positions (as well as third-party positions) throughout the Delaware and Midland Basins to North Texas.

- Southern Oklahoma Extension – Connects our SouthOK and North Texas Gathering and Processing positions (as well as third-party positions) to our North Texas to Mont Belvieu Segment.

- 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 connects Permian, North Texas and Oklahoma volumes to Mont Belvieu.

Grand Prix volumes flowing on the pipeline from the Permian Basin to Mont Belvieu are included in Grand Prix Joint Venture, while the volumes flowing from North Texas and Oklahoma to Mont Belvieu accrue solely to Targa's benefit. In the third quarter of 2019, we began full service into Mont Belvieu on Grand Prix.

Cayenne Joint Venture

In July 2017, we entered into the Cayenne Pipeline, LLC joint venture ("Cayenne") with American Midstream LLC to convert an existing 62-mile gas pipeline to an NGL pipeline connecting the VESCO plant in Venice, Louisiana to the Enterprise Products Operating LLC ("Enterprise") pipeline at Toca, Louisiana, for delivery to Enterprise's Norco Fractionator. We own a 50% interest in Cayenne. See Note 8 – Investments in Unconsolidated Affiliates for activity related to Cayenne.

Gulf Coast Express Joint Venture

In December 2017, we entered into definitive joint venture agreements to form Gulf Coast Express Pipeline LLC ("GCX") with Kinder Morgan Texas Pipeline LLC ("KMTP") and DCP Midstream Partners, LP ("DCP") for the purpose of developing 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.

Targa GCX Pipeline LLC ("GCX DevCo JV"), a joint venture between us and Stonepeak Infrastructure Partners ("Stonepeak"), and DCP each own a 25% interest, KMTP owns a 34% interest, and Altus Midstream Company owns the remaining 16% interest in GCX. KMTP serves as the 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, also committed volumes to GCX Pipeline. GCX Pipeline is designed to transport up to 1.98 Bcf/d of natural gas and commenced operations late in the third quarter of 2019. See Note 8 – Investments in Unconsolidated Affiliates for activity related to GCX.

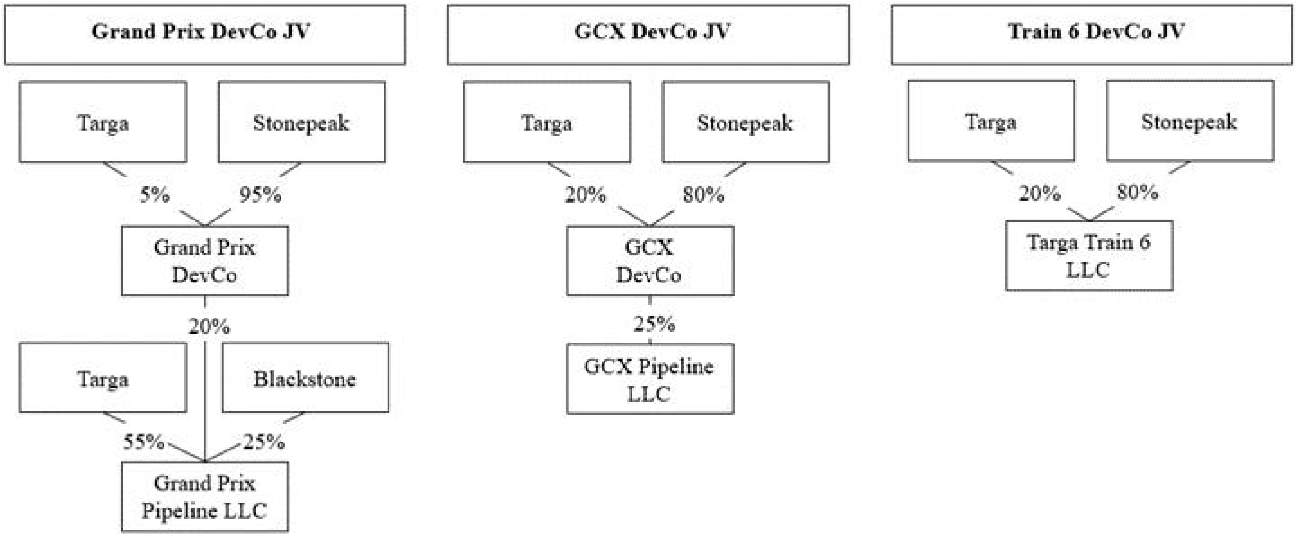
Little Missouri 4 Joint Venture

In January 2018, we formed a 50/50 joint venture in Little Missouri 4 LLC ("Little Missouri 4") with Hess Midstream Partners LP to construct a new 200 MMcf/d natural gas processing plant ("LM4 Plant") at Targa's existing Little Missouri facility. Little Missouri 4 began operations in the third quarter of 2019. Targa is the operator of the LM4 Plant. See Note 8 – Investments in Unconsolidated Affiliates for activity related to Little Missouri 4.

DevCo Joint Ventures

In February 2018, we formed three development joint ventures ("DevCo JVs") with investment vehicles affiliated with Stonepeak to fund portions of Grand Prix, GCX and an approximately 100 MBbl/d fractionator in Mont Belvieu, Texas ("Train 6"). Stonepeak owns a 95% interest in the Grand Prix DevCo JV, which owns a 20% interest in the Grand Prix Joint Venture (which does not include the extensions into Southern Oklahoma and Central Oklahoma). Stonepeak owns an 80% interest in both GCX DevCo JV, which owns our 25% interest in GCX, and Targa Train 6 LLC ("Train 6 DevCo JV"), which owns a 100% interest in the fractionation train. The Train 6 DevCo JV does not include certain fractionation-related infrastructure such as brine and storage, which were funded and are owned 100% by us. We hold the remaining interests in the DevCo JVs as well as control the management and operation of Grand Prix and Train 6.

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



For a four-year period beginning on the date that all three projects commenced commercial operations, we have the option to acquire all or part of Stonepeak's interests in the DevCo JVs. Targa may acquire up to 50% of Stonepeak's invested capital in multiple increments with a minimum of $100 million, and Stonepeak's remaining 50% interest in a single final purchase. The purchase price payable for such partial or full interests is based on a predetermined fixed return or multiple on invested capital, including distributions received by Stonepeak from the DevCo JVs. Targa controls the management of the DevCo JVs unless and until Targa declines to exercise its option to acquire Stonepeak's interests. Train 6 began operations in the second quarter of 2019. Grand Prix began full service in the third quarter of 2019. GCX Pipeline was placed in service late in the third quarter of 2019.

We hold a controlling interest in each of the DevCo JVs, as we have the majority voting interest and the supermajority voting provisions of the joint venture agreements do not represent substantive participating rights and are protective in nature to Stonepeak. As a result, we have consolidated each of the DevCo JVs in our financial statements. We continue to account for the Grand Prix Joint Venture on a consolidated basis in our consolidated financial statements, and continue to account for GCX as an equity method investment as disclosed in Note 8 – Investments in Unconsolidated Affiliates.

Carnero Joint Venture

In May 2018, Sanchez Midstream Partners LP and we merged our respective 50% interests in the Carnero gathering and Carnero processing joint ventures, which own the high-pressure Carnero gathering line and Raptor natural gas processing plant, to form an expanded 50/50 joint venture in South Texas (the "Carnero Joint Venture"). We operate the gas gathering and processing facilities in the joint venture. The Carnero Joint Venture is a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials.

Acquisitions

Permian Acquisition

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

We paid $484.1 million in cash at closing on March 1, 2017, and paid an additional $90.0 million in cash on May 30, 2017 (collectively, the "initial purchase price"). Subject to certain performance-linked measures and other conditions, additional cash of up to $935.0 million could have been payable to the sellers of New Delaware and New Midland in potential earn-out payments. The first earn-out payment was due in May 2018 and expired with no required payment. The second earn-out payment was based on a multiple of realized gross margin through February 28,2019 and resulted in a $317.1 million final payment made in May 2019.

The cash portion of the acquisition was funded primarily through the January 2017 public offering of 9,200,000 shares of common stock (including the shares sold pursuant to the underwriters' overallotment option) at a price to the public of $57.65, providing net proceeds of $524.2 million. Since March 1, 2017, financial and statistical data of New Delaware and New Midland have been included in Permian Delaware operations.

The acquired businesses, which contributed revenues of $127.9 million and a net loss of $19.8 million to us for the period from March 1, 2017 to December 31, 2017, are included in our Gathering and Processing segment. As of December 31, 2017, we had incurred $5.6 million of acquisition-related costs. These expenses are included in Other expense in our Consolidated Statements of Operations for the year ended December 31, 2017.

Pro Forma Impact of Permian Acquisition on Consolidated Statements of Operations

The following summarized unaudited pro forma Consolidated Statements of Operations information for the year ended December 31, 2017 assumes that the Permian Acquisition occurred as of January 1, 2016. We prepared the following summarized unaudited pro forma financial results for comparative purposes only. The summarized unaudited pro forma information may not be indicative of the results that would have occurred had we completed this acquisition as of January 1, 2016, or that would be attained in the future.

	December 31, 2017
	Pro Forma
Revenues	$ 8,829.0
Net income (loss)	(252.2)

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

- Reflect the amortization expense resulting from the fair value of intangible assets recognized as part of the Permian Acquisition.
- Reflect the change in depreciation expense resulting from the difference between the historical balances of the Permian Acquisition's property, plant and equipment, net, and the fair value of property, plant and equipment acquired.
- Exclude $5.6 million of acquisition-related costs incurred as of December 31, 2017 from pro forma net income for the year ended December 31, 2017.

The initial fair value of the acquired New Delaware and New Midland assets included $570.8 million cash paid, net of $3.3 million cash acquired, and contingent consideration valued at $416.3 million as of the acquisition date.

We accounted for the Permian Acquisition as an acquisition of a business under purchase accounting rules. The assets acquired and liabilities assumed related to the Permian Acquisition were recorded at their fair values as of the closing date of March 1, 2017. The fair value of the assets acquired and liabilities assumed at the acquisition date is shown below:

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

Under the acquisition method of accounting, the assets acquired and liabilities assumed are recognized at their estimated fair values, with any excess of the purchase price over the estimated fair value of the identifiable net assets acquired recorded as goodwill. Such excess of purchase price over the fair value of net assets acquired was approximately $46.6 million, which was recorded as goodwill. The goodwill is attributable to expected operational and capital synergies and is amortizable for tax purposes.

Contingent Consideration

A contingent consideration liability arising from potential earn-out payments in connection with the Permian Acquisition was recognized at its fair value, which was based on inputs that are not observable in the market and therefore represent level 3 inputs (see Note 15 – Fair Value Measurements). We agreed to pay up to an additional $935.0 million in aggregate potential earn-out payments in May 2018 and May 2019. The acquisition date fair value of the potential earn-out payments was recorded within Other long-term liabilities on our Consolidated Balance Sheets. The final earn-out payment of $317.1 million was made in May 2019. As discussed in Note 15 — Fair Value Measurements, changes in the fair value of the liability (that were not accounted for as revisions of the acquisition date fair value) have been included in Other income (expense).

Flag City Acquisition and Centrahoma Contributions

On May 9, 2017, we purchased all of the equity interests in Flag City Processing Partners, LLC ("FCPP") from Boardwalk Midstream, LLC (“Boardwalk”) and all of the equity interests in FCPP Pipeline, LLC from Boardwalk Field Services, LLC (“BFS”) for a base purchase price of $60.0 million subject to customary closing adjustments. The final adjustment to the base purchase price paid to Boardwalk was an additional $3.6 million. As part of the acquisition (the “Flag City Acquisition”), we acquired a natural gas processing plant with 150 MMcf/d of operating capacity (the “Flag City Plant”) located in Jackson County, Texas; 24 miles of gas gathering pipeline systems and related rights of ways located in Bee and Karnes counties in Texas; 102.1 acres of land surrounding the Flag City Plant; and a limited number of gas supply contracts.

In 2017, due to the redirection of the gas processing activities under the Flag City Plant contracts Flag City Plant was decommissioned and its assets were later contributed to Centrahoma Processing, LLC (“Centrahoma”), a consolidated subsidiary and joint venture that we operate, in which we have a 60% ownership interest. The remaining 40% ownership interest in Centrahoma is held by MPLX LP (“MPLX”). In 2018, utilizing the Flag City Plant assets, Centrahoma constructed the Hickory Hills Plant in Hughes County, Oklahoma (the “Hickory Hills Plant”). In October 2018, Targa also contributed the 120 MMcf/d cryogenic Tupelo Plant in Coal County, Oklahoma (the “Tupelo Plant”) to Centrahoma. In conjunction with Targa’s contribution of both the Flag City Plant assets and the Tupelo Plant, MPLX made cash contributions to Centrahoma in order to maintain its 40% ownership interest. Centrahoma is included in our Gathering and Processing segment.

We accounted for the Flag City Acquisition as an asset acquisition and capitalized less than $0.1 million of acquisition related costs as a component of the cost of assets acquired, which resulted in an allocation of $52.3 million of property, plant and equipment, $7.7 million of intangible assets for customer contracts and $3.6 million of current assets and liabilities, net.

Divestitures

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

Through our 76.8% ownership interest in Venice Energy Services Company, L.L.C. ("VESCO"), we have operated the Venice Gas Plant and the Venice gathering system. On April 4, 2017, VESCO entered into a purchase and sale agreement with Rosefield Pipeline Company, LLC, an affiliate of Arena Energy, LP, to sell its 100% ownership interests in Venice Gathering System, L.L.C. ("VGS"), a Delaware limited liability company engaged in the business of transporting natural gas in interstate commerce, under authorization granted by and subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC"), for approximately $0.4 million in cash. Historically, VGS has been reported in our Gathering and Processing segment. After the sale of VGS, we continue to operate the Venice Gas Plant through our ownership in VESCO. As a result of the sale, we recognized a loss of $16.1 million in our Consolidated Statements of Operations for the year ended December 31, 2017 as part of our Other operating (income) expense.

Sale of Refined Products and Crude Oil Storage and Terminaling Facilities

On September 12, 2018, we executed agreements to sell our Downstream refined products and crude oil storage and terminaling facilities in Tacoma, Washington, and Baltimore, Maryland, to a third party for approximately $165 million. The sale closed on October 31, 2018 and resulted in a loss of $57.5 million included within Other operating income (expense) in our Consolidated Statements of Operations. We used the proceeds to repay debt and to fund a portion of our growth capital program. The sale of these businesses is included in our Logistics and Transportation segment and does not qualify for reporting as discontinued operations as it did not represent a strategic shift that would have a major effect on our operations and financial results.

Sale of Interest in Train 7

In February 2019, we announced an extension of the 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 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. We present Train 7 on a consolidated basis in our consolidated financial statements.

Sale of Interest in Targa Badlands LLC

On April 3, 2019, we closed on the sale of a 45% interest in Targa Badlands LLC ("Targa Badlands"), the entity that holds substantially all of the assets previously wholly owned by Targa 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. Future growth capital of Targa Badlands is expected to be funded on a pro rata ownership basis. Targa Badlands pays a minimum quarterly distribution ("MQD") to Blackstone and Targa, with Blackstone having a priority right on such MQDs. Once Blackstone receives funds sufficient to meet a predetermined fixed return on their invested capital, their interest will convert to a 7.5% equity interest in Targa Badlands, and it will no longer have a priority right on MQDs. Additionally, upon a sale of Targa Badlands, Blackstone's capital contributions would have a liquidation preference equal to a predetermined fixed return on their invested capital.

After the seventh anniversary of the closing date or upon the occurrence of certain triggering events, we have the option to acquire all of Blackstone's interest in Targa Badlands for a purchase price payable to Blackstone based on their liquidation preference after taking into account all prior distributions to Blackstone, plus a set percentage on a multiple of the trailing twelve-month EBITDA of Targa Badlands. Targa will continue to control the management of Targa Badlands pending the occurrence of certain triggering events, including if Blackstone has not received funds sufficient to meet its liquidation preference and Targa has not exercised its purchase right to acquire Blackstone's interest by April 3, 2029.

We continue to be the operator of Targa Badlands and hold majority governance rights. As a result, we continue to present Targa Badlands on a consolidated basis in our consolidated financial statements and Blackstone's contributions are reflected as noncontrolling interests. The sale of interest in Targa Badlands is included in our Gathering and Processing segment. Targa Badlands is a discrete entity and the assets and credit of Targa Badlands are not available to satisfy the debts and other obligations of Targa or its other subsidiaries.

Sale of Crude Gathering and Storage Facilities

Assets and liabilities held for sale

In November 2019, we executed agreements to sell our crude gathering and storage business in Permian Delaware for approximately $134 million. The sale closed on January 22, 2020 and we used the net proceeds to repay debt and to fund a portion of our growth capital program. In relation to the sale, we classified our crude gathering and storage business assets in Permian Delaware as held for sale, and as such we measured these assets at lower of their carrying value or fair value less costs to sell. As a result, we recognized a loss of $59.5 million included within Other operating income (expense) in our Consolidated Statements of Operations for the year ended December 31, 2019. The crude gathering and storage business is included in our Gathering and Processing segment and does not qualify for reporting as a discontinued operation as its divestiture did not represent a strategic shift that would have a major effect on our operations and financial results.

The adjusted carrying amounts of the assets and liabilities held for sale are as follows:

		December 31, 2019
Current assets:		
Trade receivables	$	6.9
Intangible assets, net accumulated amortization and estimated loss on sale		52.1
Goodwill		1.4
Property, plant and equipment, net of accumulated depreciation and estimated loss on sale		77.3
Total assets held for sale	**$**	**137.7**
Current liabilities:		
Accounts payable and accrued liabilities	$	6.2
Other long-term obligations		0.2
Total liabilities held for sale	**$**	**6.4**

Note 5 — Inventories

		December 31, 2019		December 31, 2018
Commodities	$	156.5	$	151.1
Materials and supplies		5.0		13.6
	$	161.5	$	164.7

Note 6 — Property, Plant and Equipment and Intangible Assets

Property, Plant and Equipment

		December 31, 2019		December 31, 2018	Estimated Useful Lives (In Years)
Gathering systems	$	8,976.8	$	7,547.9	5 to 20
Processing and fractionation facilities		5,137.0		4,001.0	5 to 25
Terminaling and storage facilities		1,495.5		1,138.7	5 to 25
Transportation assets		2,292.4		445.1	10 to 50
Other property, plant and equipment		183.9		334.3	3 to 25
Land		159.7		144.3	—
Construction in progress		1,576.5		3,602.5	—
Finance lease right-of-use assets		48.8		—	
Property, plant and equipment		19,870.6		17,213.8	
Accumulated depreciation and amortization		(5,321.6)		(4,285.5)	
Property, plant and equipment, net	$	14,549.0	$	12,928.3	
Intangible assets	$	2,643.5	$	2,736.6	10 to 20
Accumulated amortization		(908.5)		(753.4)	
Intangible assets, net	$	1,735.0	$	1,983.2	

During the preparation of the Company's first quarter 2019 consolidated financial statements, 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 recorded the cumulative impact of the adjustment in the period of identification, resulting in a one-time $12.5 million overstatement of depreciation expense.

For each of the years ended December 31, 2019, 2018 and 2017 depreciation expense was $800.1 million, $633.3 million and $621.3 million.

Asset Impairments

We have recorded non-cash pre-tax impairments during the years ended December 31, 2019 and 2017. The impairments were a result of our assessment that forecasted undiscounted future net cash flows from operations, while positive, will not be sufficient to recover the existing total net book value of the underlying assets. For each analysis, we measured the impairment of property, plant and equipment using discounted estimated future cash flows ("DCF") including a terminal value (a Level 3 fair value measurement). The future cash flows were based on our estimates of operating and cash flow results, economic obsolescence, the business climate, contractual, legal, and other factors. We took into account current and expected industry and market conditions, including commodity prices and volumetric forecasts. The discount rate used in our DCF analysis was based on a weighted average cost of capital determined from relevant market comparisons. These carrying value adjustments are included in Impairment of property, plant and equipment in our Consolidated Statements of Operations.

In the fourth quarter of 2019, we recorded an impairment charge of $225.3 million for the partial impairment of gas processing facilities and gathering systems associated with our North Texas and Coastal operations in our Gathering and Processing segment. Underlying our assessment was the expected continuing decline in natural gas production across the Barnett Shale in North Texas and Gulf of Mexico due to the sustained low commodity price environment.

During 2017, we recorded an impairment charge of $378.0 million for the partial impairment of gas processing facilities and gathering systems associated with our North Texas operations in our Gathering and Processing segment. Given the price environment at the time, we projected a continuing decline in natural gas production across the Barnett Shale in North Texas.

Write-down of Assets

In 2019, we recorded an asset write-down of $17.9 million primarily associated with certain treating units in our Gathering and Processing segment. We wrote down the assets to their recoverable amounts using third party pricing to assess a discounted replacement cost based on the existing condition and location of the units. We consider such input to be a level 2 input in the fair value hierarchy. The write-down of assets is included in Impairment of property, plant and equipment in our Consolidated Statements of Operations.

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.

For each of the years ended December 31, 2019, 2018 and 2017 amortization expense for our intangible assets was $171.6 million, $182.6 million and $188.2 million. The estimated annual amortization expense for intangible assets is approximately $159.4 million, $149.5 million, $141.2 million, $136.0 million and $132.2 million for each of the years 2020 through 2024. As of December 31, 2019, the weighted average amortization period for our intangible assets was approximately 14.2 years.
The changes in our intangible assets are as follows:

	December 31, 2019	December 31, 2018
Beginning of period	$ 1,983.2	$ 2,165.8
Held for sale assets	(76.6)	—
Amortization	(171.6)	(182.6)
End of period	$ 1,735.0	$ 1,983.2

Asset Sales

During the second quarter of 2018, we sold our inland marine barge business, which was included in our Logistics and Transportation segment, to a third party for $69.3 million. As a result of the sale, we recognized a gain of $48.1 million in our Consolidated Statements of Operations for the year ended December 31, 2018 as part of Other operating (income) expense. We continue to own and operate two ocean-going barges.

During the fourth quarter of 2018, we exchanged a portion of our Versado gathering system, located primarily in Yoakum County, Texas, and Lea County, New Mexico, and associated contracts and assets, with a third party for consideration that includes 1) a gathering system located primarily in Lea County, New Mexico, and associated contracts and assets, 2) an initial cash payment and 3) deferred payments due semi-annually beginning on June 30, 2019, through December 31, 2022. The acquired gathering system has been integrated into the Versado gathering system. Due to the significant monetary portion of the consideration received, the exchange of these assets was accounted for as a derecognition of nonfinancial assets, and a gain of $44.4 million was recognized in our Consolidated Statements of Operations for the year ended December 31, 2018 as part of Other operating (income) expense. The gain was calculated as the difference between the fair value of the consideration received, including the fair value of acquired gathering system, less our book basis of the assets transferred.

The fair value of the acquired assets was determined using the indirect cost method of valuation, adjusted for any physical and economic obsolescence, and other management estimates. The fair value measurements of assets acquired are based on inputs that are a combination of Level 2 and Level 3 inputs, as defined in Note 15 – Fair Value Measurements.

Note 7 – Goodwill

Goodwill attributable to the WestTX and SouthTX reporting units in our Gathering and Processing segment was related to our acquisition of Atlas Energy L.P. and Atlas Pipeline Partners L.P. in 2015 (collectively the "Atlas mergers"). We also recognized goodwill of approximately $46.6 million related to the Permian Acquisition on March 1, 2017, which was attributed to the New Midland and Delaware Supersystem reporting units in our Gathering and Processing segment.

Changes in the net amounts of our goodwill are as follows:

	WestTX	SouthTX	New Midland	New Delaware	Delaware Supersystem	Total
Balance as of December 31, 2017:						
Goodwill	$ 364.5	$ 160.3	$ 23.2	$ 23.4	$ —	$ 571.4
Accumulated impairment losses	(189.8)	(125.0)	—	—	—	(314.8)
Net	174.7	35.3	23.2	23.4	—	256.6
Impairment	(174.7)	(35.3)	—	—	—	(210.0)
Balance as of December 31, 2018:						
Goodwill	364.5	160.3	23.2	23.4	—	571.4
Accumulated impairment losses	(364.5)	(160.3)	—	—	—	(524.8)
Net	—	—	23.2	23.4	—	46.6
Impairment	—	—	—	—	—	—
Reporting unit aggregation (1)	—	—	—	(23.4)	23.4	—
Balance as of December 31, 2019:						
Goodwill	364.5	160.3	23.2	—	23.4	571.4
Goodwill allocated to held for sale assets	—	—	—	—	(1.4)	(1.4)
Accumulated impairment losses	(364.5)	(160.3)	—	—	—	(524.8)
Net	—	—	23.2	—	22.0	45.2

(1) In 2019, we began aggregating the results of Delaware Supersystem activity, including New Delaware. Discrete financial information for New Delaware is no longer available and management now reviews aggregate Delaware Supersystem operating results.

The future cash flows and resulting fair values of these reporting units are sensitive to changes in crude oil, natural gas and NGL prices. The direct and indirect effects of significant declines in commodity prices from the date of acquisition would likely cause the fair values of these reporting units to fall below their carrying values, and could result in an impairment of goodwill.

As described in Note 3 – Significant Accounting Policies, we evaluate goodwill for impairment at least annually on November 30, or more frequently if we believe necessary based on events or changes in circumstances. Our annual evaluations utilized an income approach including a terminal value to estimate the fair values of our reporting units based on a DCF analysis. The future cash flows for our reporting units are based on our estimates, at that time, of future revenues, income from operations and other factors, such as working capital and timing of capital expenditures. We take into account current and expected industry and market conditions, including commodity pricing and volumetric forecasts in the basins in which the reporting units operate. The discount rates used in our DCF analysis are based on a weighted average cost of capital determined from relevant market comparisons.

The fair value measurements utilized for the evaluation of goodwill for impairment are based on inputs that are not observable in the market and therefore represent Level 3 inputs, as defined in Note 15 – Fair Value Measurements. These inputs require significant judgments and estimates at the time of valuation.

Our 2018 annual evaluation of goodwill for impairment was completed in the fourth quarter of 2018. Due to the impact of lower forecasted commodity prices and a reduction in forecasted volumes as a result of changes in producers' drilling activity, we recorded impairment expense of $210.0 million in our Consolidated Statements of Operations, representing the impairment of the remaining goodwill for WestTX and SouthTX.

We did not record any goodwill impairment charges for the year ended December 31, 2019, as the fair values of all reporting units exceeded their accounting carrying values. While no impairment is indicated, there is goodwill being allocated to held for sale assets.

Note 8 – Investments in Unconsolidated Affiliates

Our investments in unconsolidated affiliates consist of the following:

Gathering and Processing Segment

- two operated joint ventures in South Texas: a 75% interest in T2 LaSalle Gathering Company L.L.C. ("T2 LaSalle") and a 50% interest in T2 Eagle Ford Gathering Company L.L.C. ("T2 Eagle Ford"), (together the "T2 Joint Ventures"); and
- a 50% operated ownership interest in Little Missouri 4.

Logistics and Transportation Segment

- a 25% non-operated ownership interest in GCX;
- a 38.8% non-operated ownership interest in Gulf Coast Fractionators LP ("GCF"); and
- a 50% operated ownership interest in Cayenne.

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.

See Note 4 – Joint Ventures, Acquisitions and Divestitures for discussion of the formation of our GCX and Little Missouri 4 and our acquisition of interests in Cayenne.

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

	Balance at December 31, 2016	Equity Earnings (Loss)	Cash Distributions	Acquisition	Contributions	Balance at December 31, 2017
GCX	$ —	$ —	$ —	$ —	$ —	$ —
Little Missouri 4	—	—	—	—	—	—
T2 Eagle Ford	118.6	(10.6)	—	—	1.2	109.2
T2 LaSalle	58.6	(4.9)	—	—	0.4	54.1
GCF	46.1	12.4	(12.7)	—	—	45.8
Cayenne	—	—	—	5.0	3.6	8.6
T2 EF Cogen	17.5	(13.9)	—	—	0.3	3.9
Agua Blanca	—	—	—	—	—	—
Total	$ 240.8	$ (17.0)	$ (12.7)	$ 5.0	$ 5.5	$ 221.6

	Balance at December 31, 2017	Equity Earnings (Loss)	Cash Distributions (1)	Acquisition (Disposition)	Contributions (2)	Balance at December 31, 2018
GCX (3)	$ —	$ 0.8	$ —	$ —	$ 210.8	$ 211.6
Little Missouri 4	—	—	(8.0)	—	75.3	67.3
T2 Eagle Ford	109.2	(10.2)	—	—	—	99.0
T2 LaSalle	54.1	(4.9)	—	—	0.1	49.3
GCF	45.8	16.8	(22.3)	—	—	40.3
Cayenne	8.6	6.4	(4.0)	—	5.6	16.6
T2 EF Cogen	3.9	(1.8)	—	(2.1)	—	—
Agua Blanca	—	0.2	—	3.5	2.7	6.4
Total	$ 221.6	$ 7.3	$ (34.3)	$ 1.4	$ 294.5	$ 490.5

	Balance at December 31, 2018	Equity Earnings (Loss)	Cash Distributions	Disposition	Contributions	Balance at December 31, 2019
GCX (3)	$ 211.6	$ 27.7	$ (25.3)	$ —	$ 233.5	$ 447.5
Little Missouri 4	67.3	3.4	—	—	33.0	103.7
T2 Eagle Ford (4)	99.0	(9.4)	—	—	—	89.6
T2 LaSalle (4)	49.3	(4.5)	—	—	—	44.8
GCF	40.3	16.1	(19.2)	—	—	37.2
Cayenne	16.6	7.2	(8.2)	—	0.3	15.9
Agua Blanca	6.4	(1.5)	(0.4)	(4.5)	—	—
Total	$ 490.5	$ 39.0	$ (53.1)	$ (4.5)	$ 266.8	$ 738.7

(1) Includes an $8.0 million distribution from Little Missouri 4 as a reimbursement of pre-formation expenditures.
(2) Includes a $16.0 million initial contribution of property, plant and equipment to Little Missouri 4.
(3) As discussed in Note 4 – Joint Ventures, Acquisitions and Divestitures, our 25% interest in GCX is owned by 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.
(4) The carrying values of the T2 Joint Ventures include the effects of the Atlas mergers purchase accounting, which determined fair values for the joint ventures as of the date of acquisition. As of December 31, 2019, $23.1 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.

Our equity loss for the year ended December 31, 2017 includes the effect of an impairment in the carrying value of our investment in T2 EF Cogen. As a result of the decrease in current and expected future utilization of the underlying cogeneration assets, we determined that factors indicated that a decrease in the value of our investment occurred that was other than temporary. As a result of this evaluation, we recorded an impairment loss of approximately $12.0 million in the first quarter of 2017, which represented our proportionate share (50%) of an impairment charge recorded by the joint venture, as well as our impairment of the unamortized excess fair value resulting from the Atlas mergers.

Effective December 31, 2018: (i) we conveyed our 50% ownership interest in T2 EF Cogen to our joint venture partner and received a distribution of certain assets from the joint venture; and, (ii) we were named as operator of the T2 Joint Ventures. On April 1, 2019, we assumed the operatorship of the T2 Joint Ventures.

During 2019, we closed on the sale of an equity-method investment for $73.8 million, of which $3.5 million contingent consideration was received in January 2020. As a result of the sale, we recognized a gain of $69.3 million reported in Gain (loss) from sale of equity-method investment.

The following tables summarize the combined financial information of our investments in unconsolidated affiliates (all data presented on a 100% basis):

	December 31, 2019	December 31, 2018
	(In millions)	
Current assets	$ 136.3	$ 200.7
Non-current assets	$ 2,291.6	$ 1,329.7
Current liabilities	$ 93.8	$ 233.9
Non-current liabilities	$ 3.4	$ 179.2
Net assets	$ 2,330.7	$ 1,117.3

	Year Ended December 31,		
	2019	2018	2017
		(In millions)	
Operating revenues	$ 265.5	$ 130.6	$ 84.3
Operating expenses	$ 144.2	$ 96.9	$ 80.5
Net income (loss)	$ 87.7	$ 34.7	$ 3.4

Note 9 — Accounts Payable and Accrued Liabilities

	December 31, 2019	December 31, 2018
Commodities	$ 683.6	$ 721.9
Other goods and services	311.5	474.5
Interest	125.4	79.4
Permian Acquisition contingent consideration	—	308.2
Income and other taxes	62.0	45.4
Accrued distributions to noncontrolling interests	91.7	—
Other	9.5	7.5
	$ 1,283.7	$ 1,636.9

Accounts payable and accrued liabilities includes $21.6 million and $52.2 million of liabilities to creditors to whom we have issued checks that remain outstanding as of December 31, 2019 and December 31, 2018.

Permian Acquisition Contingent Consideration

As a result of the Permian Acquisition, we included the fair value of the contingent consideration in accounts payable and accrued liabilities as of December 31, 2018. The contingent consideration earn-out period ended on February 28, 2019 and resulted in a $317.1 million payment in May 2019.

Note 10 — Debt Obligations

	December 31, 2019	December 31, 2018
Current:		
Securitization Facility, due December 2020 (1)	$ 370.0	$ 280.0
Senior unsecured notes, 4⅛% fixed rate, due November 2019 (2)	—	749.4
	370.0	1,029.4
Debt issuance costs, net of amortization	—	(1.5)
Finance lease liabilities	12.2	—
Current debt obligations	382.2	1,027.9
Long-term:		
Senior secured revolving credit facility, variable rate, due June 2023 (3)	—	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	—
5½% fixed rate, due March 2030	1,000.0	—
TPL notes, 4¾% fixed rate, due November 2021 (4)	6.5	6.5
TPL notes, 5⅞% fixed rate, due August 2023 (4)	48.1	48.1
Unamortized premium	0.3	0.3
	7,028.5	5,228.5
Debt issuance costs, net of amortization	(49.1)	(31.1)
Finance lease liabilities	25.8	—
Long-term debt	7,005.2	5,197.4
Total debt obligations	$ 7,387.4	$ 6,225.3
Irrevocable standby letters of credit outstanding (3)	$ 88.2	$ 79.5

(1) As of December 31, 2019, we had $400.0 million of qualifying receivables under our $400.0 million Securitization Facility, resulting in availability of $30.0 million.
(2) The 4⅛% Senior Notes due 2019 were redeemed in full on February 11, 2019.
(3) As of December 31, 2019, availability under our $2.2 billion senior secured revolving credit facility ("TRP Revolver") was $2,111.8 million.
(4) "TPL" refers to Targa Pipeline Partners LP.

The following table shows the contractually scheduled maturities of our debt obligations outstanding at December 31, 2019, for the next five years, and in total thereafter:

	Scheduled Maturities of Debt (in millions)						
	Total	2020	2021	2022	2023	2024	After 2024
Senior unsecured notes	$ 7,028.2	$ —	$ 6.5	$ —	$ 1,191.6	$ 580.1	$ 5,250.0
Securitization Facility	370.0	370.0	—	—	—	—	—
Total	$ 7,398.2	$ 370.0	$ 6.5	$ —	$ 1,191.6	$ 580.1	$ 5,250.0

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

	Range of Interest Rates Incurred	Weighted Average Interest Rate Incurred
TRP Revolver	3.5% - 4.7%	4.1%
Securitization Facility	2.6% - 3.4%	3.1%

Compliance with Debt Covenants

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

Debt Obligations

Revolving Credit Facility

The TRP Revolver, which has a maturity date of June 2023, provides available commitments up to $2.2 billion and allows us to request up to $500.0 million in additional commitments.

The TRP Revolver provides for certain changes to occur upon the Partnership receiving an investment grade credit rating from Moody's Investors Service, Inc. ("Moody's") or Standard & Poor's Corporation ("S&P"), including the release of the security interests in all collateral at the request of the Partnership.

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

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

The TRP Revolver is collateralized by a pledge of assets and equity from certain of the Partnership's subsidiaries. Borrowings are guaranteed by our restricted subsidiaries.

The TRP Revolver requires us to maintain a total leverage ratio (the ratio of consolidated indebtedness to our consolidated Adjusted EBITDA, in each case as defined in the TRP Revolver), determined as of the last day of each quarter for the four-fiscal quarter period ending on the date of determination, of no more than (a) before the collateral release date, 5.50 to 1.00 and (b) upon and after the collateral release date, 5.25 to 1.00 (or 5.50 to 1.00 during a specified acquisition period).

The TRP Revolver also requires us to maintain an interest coverage ratio of no less than 2.25 to 1.00 determined as of the last day of each quarter for the four-fiscal quarter period ending on the date of determination. For any four-fiscal quarter period during which a material acquisition or disposition occurs, the total leverage ratio and interest coverage ratio will be determined on a pro forma basis as though such event had occurred as of the first day of such four-fiscal quarter period.

The TRP Revolver restricts our ability to make distributions of available cash to unitholders if a default or an event of default (as defined in the TRP Revolver) exists or would result from such distribution. In addition, the TRP Revolver contains various covenants that may limit, among other things, our ability to incur indebtedness, grant liens, make investments, repay or amend the terms of certain other indebtedness, merge or consolidate, sell assets, and engage in transactions with affiliates (in each case, subject to our right to incur indebtedness or grant liens in connection with, and convey accounts receivable as part of, a permitted receivables financing, the aggregate principal of which shall not exceed $400,000,000).

On June 7, 2019, the Partnership entered into the First Amendment to the TRP Revolver (the "First Amendment"). The First Amendment, among other things, amended the TRP Revolver to (a) increase the maximum percentage of Consolidated EBITDA attributable to Material Project EBITDA. Adjustments from 20% to 30% solely for the fiscal periods from and including the fiscal period ending June 30, 2019 until and including the fiscal period ending June 30, 2020, after which time the maximum percentage of Consolidated EBITDA attributable to Material Project EBITDA. Adjustments shall revert to 20% of Consolidated EBITDA and (b) include in the calculation of Consolidated EBITDA for a period certain cash distributions received by the Partnership (or and of its consolidated restricted subsidiaries) from unrestricted subsidiaries (or entities that are not subsidiaries) after the end of such period but on or prior to the date that TRP calculates Consolidated EBITDA for such period.

Accounts Receivable Securitization Facility

On December 6, 2019, we renewed and amended the Securitization Facility by changing the termination date from December 6, 2019 to December 4, 2020. As of December 31, 2019, total funding under the Securitization Facility was $370.0 million.

The Securitization Facility provides up to $400.0 million of borrowing capacity at LIBOR market index rates plus a margin through December 4, 2020. Under the Securitization Facility, certain Partnership subsidiaries sell or contribute certain qualifying receivables, without recourse, to another of its consolidated subsidiaries (Targa Receivables LLC or "TRLLC"), a special purpose consolidated subsidiary created for the sole purpose of the Securitization Facility. TRLLC, in turn, sells an undivided percentage ownership in the eligible receivables to third-party financial institutions. Sold or contributed receivables up to the amount of the outstanding debt under the Securitization Facility are not available to satisfy the claims of the creditors of the selling or contributing subsidiaries or the Partnership. Any excess receivables are eligible to satisfy the claims.

Senior Unsecured Notes

All issues of senior unsecured notes are pari passu with existing and future senior indebtedness. They are senior in right of payment to any of our future subordinated indebtedness and are unconditionally guaranteed by us and our restricted subsidiaries. These notes are effectively subordinated to all secured indebtedness under the TRP Revolver and the Securitization Facility, which is secured by accounts receivable pledged under the facility, to the extent of the value of the collateral securing that indebtedness. Interest on all issues of senior unsecured notes is payable semi-annually in arrears.

Our senior unsecured notes and associated indenture agreements restrict our ability to make distributions to unitholders in the event of default (as defined in the indentures). The indentures also restrict our ability and the ability of certain of our subsidiaries to: (i) incur additional debt or enter into sale and leaseback transactions; (ii) pay certain distributions on or repurchase equity interests (only if such distributions do not meet specified conditions); (iii) make certain investments; (iv) incur liens; (v) enter into transactions with affiliates; (vi) merge or consolidate with another company; and (vii) transfer and sell assets. These covenants are subject to a number of important exceptions and qualifications. If at any time when the notes are rated investment grade by either Moody's or S&P and no Default or Event of Default (each as defined in the indentures) has occurred and is continuing, many of such covenants will terminate and the Partnership and its subsidiaries will cease to be subject to such covenants.

We may redeem the senior unsecured notes, in whole or in part, at any time prior to their maturity at a redemption price equal to the principal amount plus an applicable make-whole premium, plus accrued and unpaid interest and liquidation damages, if any, to the redemption date, as specified in the indenture of each series.

We may also redeem up to 35% of the aggregate principal amount of each series of notes at the redemption dates and prices set forth in the indentures plus accrued and unpaid interest and liquidation damages, if any, to the redemption date with the net cash proceeds of one or more equity offerings, provided that: (i) at least 65% of the aggregate principal amount of each of the notes (excluding notes held by us) remains outstanding immediately after the occurrence of such redemption; and (ii) the redemption occurs within 180 days of the date of the closing of such equity offering.

We may also redeem all or part of each of the series of senior unsecured notes on or after the redemption dates as specified in the indenture of each series at the redemption prices as specified in the indenture of each series plus accrued and unpaid interest to the redemption date and liquidation damages, if any, on the notes redeemed.

Senior Unsecured Notes Issuances

In October 2017, we issued $750.0 million aggregate principal amount of 5% senior notes due January 2028 (the "5% Senior Notes due 2028"). We used the net proceeds of $744.1 million after costs from this offering to redeem our 5% Senior Notes, reduce borrowings under our credit facilities, and for general partnership purposes.

In April 2018, we issued $1.0 billion aggregate principal amount of 5⅞% senior notes due April 2026 (the "5⅞% Senior Notes due 2026"). We used net proceeds of $991.9 million after costs from this offering to repay borrowings under our credit facilities and for general partnership purposes.

In January 2019, we 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 $1,486.6 million. The net proceeds from the issuance were used to redeem in full our outstanding 4⅛% Senior Notes due 2019 at par value plus accrued interest through the redemption date and the remainder, with the remainder used for general partnership purposes, which included repayment of borrowings under its credit facilities.

In November 2019, the Partnership issued $1.0 billion aggregate principal amount of 5½% Senior Notes due March 2030, resulting in net proceeds of $990.8 million. The net proceeds from the issuance were used to repay borrowings under the Partnership's credit facilities and for general partnership purposes.

Debt Repurchases & Extinguishments

In June 2017, we redeemed our outstanding 6⅜% Senior Notes due August 2022 ("6⅜% Senior Notes"), totaling $278.7 million in aggregate principal amount, at a price of 103.188% of the principal amount plus accrued interest through the redemption date. The redemption resulted in a $10.7 million loss, which is reflected as Gain (loss) from financing activities in our Consolidated Statements of Operations for the year ended December 31, 2017, consisting of premiums paid of $8.9 million and a non-cash loss to write-off $1.8 million of unamortized debt issuance costs.

In October 2017, we redeemed our outstanding 5% Senior Notes due 2018 at par value plus accrued interest through the redemption date. The redemption resulted in a non-cash Gain (loss) from financing activities to write-off $0.2 million of unamortized debt issuance costs during the year ended December 31, 2017.

In February 2019, we redeemed our 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.

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

Debt Repurchases and Extinguishments Summary

The following table summarizes the impact of debt repurchases and extinguishments that are included in our Consolidated Statements of Operations:

	2019	2018	2017
Premium over face value paid upon redemption:			
6⅜% Senior Notes	—	—	8.9
Write-off of debt issuance costs:			
TRP Revolver	—	1.3	—
4⅛% Senior Notes	1.4	—	—
5% Senior Notes	—	—	0.2
6⅜% Senior Notes	—	—	1.8
Loss (gain) from financing activities	$ 1.4	$ 1.3	$ 10.9

Note 11 — Other Long-term Liabilities

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

	December 31, 2019	December 31, 2018
Asset retirement obligations	$ 65.8	$ 55.0
Deferred revenue	172.0	175.5
Operating lease liabilities	18.2	—
Other liabilities	4.0	3.3
Total long-term liabilities	$ 260.0	$ 233.8

Asset Retirement Obligations

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

	2019	2018
Beginning of period	$ 55.0	$ 50.3
Additions (1)	11.8	—
Change in cash flow estimate	(5.1)	1.8
Accretion expense	4.7	3.7
Retirement of ARO	(0.6)	(0.8)
End of period	$ 65.8	$ 55.0

(1) Amount reflects additions of ARO related to the commencement of operations of Grand Prix.

Mandatorily Redeemable Preferred Interests

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

The joint ventures, collectively, hold $1.9 billion face value in notes receivable from our partner, which are due July 2042. The interest rate payable under the notes receivable is a variable LIBOR-based rate. For the years ended December 31, 2019, 2018 and 2017, interest earned on the notes receivable of $10.2 million, $9.7 million, and $10.3 million, exclusive of the priority return payable to our partner, is reflected within Interest expense, net in our Consolidated Statements of Operations. We have accounted for the notes receivable at fair value. Upon redemption: (i) the distributable value of our partner's interest in each joint venture is required to be adjusted by mutual agreement or under a valuation procedure outlined in each joint venture agreement based, among other things, on changes in the market value of the joint venture's assets allocable to our partner (including the value of the notes receivable); and (ii) the parties are obligated to set off the value of the notes receivable from our partner against the value of our partner's interest in the applicable joint venture. For reporting purposes under GAAP, an estimate of our partner's interest in each joint venture is required to be recorded as if the redemption had occurred on the reporting date. Because redemption will not be required until at least 2022, the actual value of our partner's allocable share of each joint venture's assets at the time of redemption may differ from our estimate of redemption value as of December 31, 2019.

In February 2018, the parties amended the agreements governing each joint venture to: (i) increase the priority return for capital contributions made on or after January 1, 2017; and (ii) add a non-consent feature effective with respect to certain capital projects undertaken on or after January 1, 2017. During the year ended December 31, 2018, the change in estimated redemption value of the mandatorily redeemable preferred interests of $72.1 million is primarily attributable to the amendments. Income attributable to mandatorily redeemable preferred interests totaled $4.1 million during the year ended December 31, 2018. The estimated redemption value did not change during the year ended December 31, 2019.

Deferred Revenue

Deferred revenue as of December 31, 2019 and December 31, 2018, was $172.0 million and $175.5 million, respectively, which 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. The payments were received 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 dependent upon resolution of the dispute with Vitol.

Deferred revenue also includes nonmonetary consideration received in a 2015 amendment (the "gas contract amendment") to a gas gathering and processing agreement. We measured the estimated fair value of the gathering assets transferred to us using significant other observable inputs representative of a Level 2 fair value measurement. In December 2017, we received monetary consideration to further amend the terms of the gas gathering and processing agreement. The deferred revenue related to these amendments is being recognized on a straight-line basis through the end of the agreement's term in 2035.

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

For the years ended December 31, 2019, 2018 and 2017, we recognized approximately $3.9 million, $3.9 million and $3.1 million of revenue for these transactions.

The following table shows the components of deferred revenue:

	December 31, 2019	December 31, 2018
Splitter agreement	$ 129.0	$ 129.0
Gas contract amendment	39.8	42.2
Other deferred revenue	3.2	4.3
Total deferred revenue	$ 172.0	$ 175.5

The following table shows the changes in deferred revenue:

	2019	2018
Balance at December 31, 2018	$ 175.5	$ 136.2
Additions	0.4	43.2
Revenue recognized	(3.9)	(3.9)
Balance at December 31, 2019	$ 172.0	$ 175.5

Permian Acquisition Contingent Consideration

Upon closing of the Permian Acquisition, a contingent consideration liability arising from potential earn-out provisions was recognized at its preliminary fair value. The first potential earn-out payment would have occurred in May 2018 while the second potential earn-out payment would occur in May 2019. The acquisition date fair value of the contingent consideration of $416.3 million was recorded within Other long-term liabilities on our Consolidated Balance Sheets. For the period from the acquisition date to December 31, 2017, the fair value of the contingent consideration decreased by $99.3 million, primarily related to reductions in forecasted volumes and gross margin as a result of changes in producers' drilling activity in the region since the acquisition date, bringing the total Permian Acquisition contingent consideration to $317.0 million at December 31, 2017, of which $6.8 million was a current liability.

The portion of the earn-out due in 2018 expired with no required payment. For the period from December 31, 2017 to December 31, 2018, the fair value of the contingent consideration decreased by $8.8 million, primarily attributable to lower actual and forecasted volumes for the remainder of the earn-out period, partially offset by a shorter discount period. At December 31, 2018, the fair value of the second potential earn-out payment of $308.2 million was recorded as a component of accounts payable and accrued liabilities, which are current liabilities on our Consolidated Balance Sheets. The contingent consideration earn-out period ended on February 28, 2019 and resulted in a $317.1 million payment in May 2019.

The following table shows the changes in the fair value of the contingent consideration related to the Permian Acquisition:

	Year Ended December 31, 2019	Year Ended December 31, 2018	March 1, 2017 to December 31, 2017
Beginning of period	$ 308.2	$ 317.0	$ 416.3
Increase (decrease) in fair value, included in Other income (expense)	8.9	(8.8)	(99.3)
Earn-out payment	(317.1)	—	—
End of period	—	308.2	317.0
Less: Current portion	—	(308.2)	(6.8)
Long-term balance at end of period	$ —	$ —	310.2

See Note 15 – Fair Value Measurements for additional discussion of the fair value methodology.

Note 12 – 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 5 years, some of which include options to extend the lease term for up to 10 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	December 31, 2019
Right-of-use assets		
Operating leases, gross	Other long-term assets	$ 31.6
Finance leases, gross	Property, plant and equipment	48.8
Lease liabilities		
Current:		
Operating leases	Accounts payable and accrued liabilities	$ 6.5
Finance leases	Current debt obligations	12.2
Non-current:		
Operating leases	Other long-term liabilities	$ 18.2
Finance leases	Long-term debt	25.8

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:

	Year Ended December 31, 2019
Lease cost	
Operating lease cost	$ 8.2
Short-term lease cost	30.0
Variable lease cost	4.9
Finance lease cost	
Amortization of right-of-use assets	13.1
Interest expense	1.6
Total lease cost	$ 57.8

During the years ended December 31, 2018 and 2017, total operating leases expense incurred were $51.9 million and $46.2 million, which includes short-term leases for compressors and equipment.

Other supplemental information related to our leases are as follows:

	Year Ended December 31, 2019
Cash paid for amounts included in the measurement of lease liabilities:	
Operating cash flows for operating leases	$ 8.2
Operating cash flows for finance leases	1.6
Financing cash flows for finance leases	11.5

The weighted-average remaining lease terms for operating leases and finance leases are 4 years and 3 years, respectively. The weighted-average discount rates for operating leases and finance leases are 3.9% and 3.9%, respectively.

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

	Operating Leases	Finance Leases
Future Minimum Lease Payments Beginning After December 31,		
2019	$ 7.4	$ 13.4
2020	6.8	11.7
2021	5.7	10.2
2022	4.2	4.7
2023	2.3	0.5
Thereafter	0.4	—
Total undiscounted cash flows	26.8	40.5
Less imputed interest	(2.1)	(2.5)
Total lease liabilities	$ 24.7	$ 38.0

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

	Leases
2019	$ 20.5
2020	17.7
2021	14.9
2022	12.6
2023	6.0
Thereafter	1.7
Total payments	$ 73.4

Note 13 — Partnership Units and Related Matters

Distributions

TRC is entitled to receive all available Partnership distributions after payment of preferred unit distributions each quarter.

The following details the distributions declared or paid by the Partnership during 2019, 2018 and 2017:

Three Months Ended	Date Paid	Total Distributions	Distributions to Targa Resources Corp.
2019			
December 31, 2019	February 13, 2020	$ 241.9	$ 239.1
September 30, 2019	November 13, 2019	242.1	239.3
June 30, 2019	August 13, 2019	242.4	239.6
March 31, 2019	April 5, 2019	437.8	435.0
2018			
December 31, 2018	February 13, 2019	241.3	238.5
September 30, 2018	November 13, 2018	237.6	234.8
June 30, 2018	August 13, 2018	234.0	231.2
March 31, 2018	May 11, 2018	229.7	226.9
2017			
December 31, 2017	February 12, 2018	228.5	225.7
September 30, 2017	November 10, 2017	225.4	222.6
June 30, 2017	August 10, 2017	225.4	222.6
March 31, 2017	May 11, 2017	209.6	206.8

Contributions

All capital contributions are allocated 98% to the limited partner and 2% to our general partner; however, no units will be issued for those contributions. For the years ended December 31, 2019, 2018 and 2017, Targa made total capital contributions to us of $200.0 million, $600.0 million and $1,720.0 million.

Preferred Units

Our Preferred Units are listed on the NYSE under the symbol "NGLS/PA."

Distributions on our 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 our general partner. Distributions on our 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 our Preferred Units will accumulate at an annual floating rate equal to the one-month LIBOR plus a spread of 7.71%.

The Preferred Units, with respect to anticipated monthly distributions, rank:

- senior to our common units and to each other class or series of Partnership interests or other equity securities established after the original issue date of the Preferred Units that is not expressly made senior to or pari passu with the Preferred Units as to the payment of distributions;

- pari passu with any class or series of Partnership interests or other equity securities established after the original issue date of the Preferred Units that is not expressly made senior or subordinated to the Preferred Units as to the payment of distributions;

- junior to all of our existing and future indebtedness (including (i) indebtedness outstanding under the TRP Revolver, (ii) our senior notes and (iii) indebtedness outstanding under the Securitization Facility and other liabilities with respect to assets available to satisfy claims against us; and

- junior to each other class or series of Partnership interests or other equity securities established after the original issue date of the Preferred Units that is expressly made senior to the Preferred Units as to the payment of distributions.

At any time on or after November 1, 2020, we may redeem the Preferred Units, in whole or in part, from any source of funds legally available for such purpose, by paying $25.00 per unit plus an amount equal to all accumulated and unpaid distributions thereon to the date of redemption, whether or not declared. In addition, we (or a third party with our prior written consent) may redeem the Preferred Units following certain changes of control, as described in our Partnership Agreement. If we do not (or a third party with our prior written consent does not) exercise this option, then the holders of the Preferred Units ("Preferred Unitholders") have the option to convert the Preferred Units into a number of common units per Preferred Unit as set forth in our Partnership Agreement. If we exercise (or a third party with our prior written consent exercises) our redemption rights relating to any Preferred Units, the Preferred Unitholders will not have the conversion right described above with respect to the Preferred Units called for redemption. The Preferred Unitholders have no voting rights except for certain exceptions set forth in our Partnership Agreement.

As of December 31, 2019, we have 5,000,000 Preferred Units outstanding. We paid $11.3 million of distributions each year to the Preferred Unitholders for 2019, 2018 and 2017.

In January and February 2020, the board of directors of our general partner declared a cash distribution of $0.1875 per Preferred Unit, resulting in approximately $0.9 million in distributions each month. The distributions declared in January were paid on February 18, 2020 and the distributions declared in February will be paid on March 16, 2020.

Note 14 — 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 Transportation segment and (iii) natural gas transportation basis risk in our Logistics and Transportation 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 December 31, 2019, the notional volumes of our commodity derivative contracts were:

Commodity	Instrument	Unit	2020	2021	2022	2023	2024
Natural Gas	Swaps	MMBtu/d	127,230	123,751	46,100	-	-
Natural Gas	Basis Swaps	MMBtu/d	364,275	344,292	210,000	200,000	40,000
NGL	Swaps	Bbl/d	23,105	11,196	6,036	-	-
NGL	Futures	Bbl/d	16,844	-	-	-	-
Condensate	Swaps	Bbl/d	5,471	3,654	1,610	-	-

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:

	Balance Sheet Location	Fair Value as of December 31, 2019 Derivative Assets	Fair Value as of December 31, 2019 Derivative Liabilities	Fair Value as of December 31, 2018 Derivative Assets	Fair Value as of December 31, 2018 Derivative Liabilities
Derivatives designated as hedging instruments					
Commodity contracts	Current	$ 102.1	$ 11.6	$ 112.5	$ 18.9
	Long-term	33.7	6.4	31.6	1.5
Total derivatives designated as hedging instruments		$ 135.8	$ 18.0	$ 144.1	$ 20.4
Derivatives not designated as hedging instruments					
Commodity contracts	Current	$ 1.2	$ 92.5	$ 2.8	$ 14.7
	Long-term	1.8	34.4	2.5	1.6
Total derivatives not designated as hedging instruments		$ 3.0	$ 126.9	$ 5.3	$ 16.3
Total current position		$ 103.3	$ 104.1	$ 115.3	$ 33.6
Total long-term position		35.5	40.8	34.1	3.1
Total derivatives		$ 138.8	$ 144.9	$ 149.4	$ 36.7

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

December 31, 2019	Gross Presentation Asset	Gross Presentation Liability	Gross Presentation Collateral	Pro Forma Net Presentation Asset	Pro Forma Net Presentation Liability
Current Position					
Counterparties with offsetting positions or collateral	$ 99.8	$ (85.0)	$ (4.9)	$ 56.0	$ (46.1)
Counterparties without offsetting positions - assets	3.5	-	-	3.5	-
Counterparties without offsetting positions - liabilities	-	(19.1)	-	-	(19.1)
	103.3	(104.1)	(4.9)	59.5	(65.2)
Long Term Position					
Counterparties with offsetting positions or collateral	33.3	(40.5)	-	18.1	(25.3)
Counterparties without offsetting positions - assets	2.2	-	-	2.2	-
Counterparties without offsetting positions - liabilities	-	(0.3)	-	-	(0.3)
	35.5	(40.8)	-	20.3	(25.6)
Total Derivatives					
Counterparties with offsetting positions or collateral	133.1	(125.5)	(4.9)	74.1	(71.4)
Counterparties without offsetting positions - assets	5.7	-	-	5.7	-
Counterparties without offsetting positions - liabilities	-	(19.4)	-	-	(19.4)
	$ 138.8	$ (144.9)	$ (4.9)	$ 79.8	$ (90.8)

December 31, 2018	Gross Presentation Asset	Gross Presentation Liability	Gross Presentation Collateral	Pro Forma Net Presentation Asset	Pro Forma Net Presentation 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 our senior secured lenders. Some of our hedges are futures contracts executed through brokers that clear the hedges through an exchange. We maintain a margin deposit with the brokers 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 liability of $6.1 million as of December 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 and amounts reclassified from OCI to revenue for the periods indicated:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivatives (Effective Portion)		
	2019	2018	2017
Commodity contracts	$ 135.6	$ 132.5	$ (28.8)

Location of Gain (Loss)	Gain (Loss) Reclassified from OCI into Income (Effective Portion)		
	2019	2018	2017
Revenues	138.0	(38.4)	(44.6)

Based on valuations as of December 31, 2019, we expect to reclassify commodity hedge related deferred gains of $117.7 million included in accumulated other comprehensive income into earnings before income taxes through the end of 2022, with $90.9 million of gains to be reclassified over the next twelve months.

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. For the year ended December 31, 2019, the unrealized mark-to-market losses are primarily attributable to unfavorable movements in natural gas forward basis prices.

Derivatives Not Designated as Hedging Instruments	Location of Gain Recognized in Income on Derivatives	Gain (Loss) Recognized in Income on Derivatives		
		2019	2018	2017
Commodity contracts	Revenue	$ (142.1)	$ (32.5)	$ (5.1)

See Note 15 – Fair Value Measurements and Note 25 – Segment Information for additional disclosures related to derivative instruments and hedging activities.

Note 15 — 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 December 31, 2019, a net liability position of $6.1 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 $114.2 million, ignoring an adjustment for counterparty credit risk. If forward pricing on natural gas, NGLs and crude oil were to decrease by 10%, the result would be a fair value reflecting a net asset of $102.1 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 TRP Revolver and the Securitization Facility are based on carrying value, which approximates fair value as their interest rates are based on prevailing market rates; and

- 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:

	December 31, 2019				
		Fair Value			
	Carrying 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)	$ 136.5	$ 136.5	$ —	$ 136.2	$ 0.3
Liabilities from commodity derivative contracts (1)	142.6	142.6	—	142.0	0.6
TPL contingent consideration (2)	2.3	2.3	—	—	2.3
Financial Instruments Recorded on Our Consolidated Balance Sheets at Carrying Value:					
Cash and cash equivalents	291.1	291.1	—	—	—
TRP Revolver	—	—	—	—	—
Senior unsecured notes	7,028.5	7,376.9	—	7,376.9	—
Accounts receivable securitization facility	370.0	370.0	—	370.0	—

	December 31, 2018				
		Fair Value			
	Carrying 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	203.3	203.3	—	—	—
TRP Revolver	700.0	700.0	—	700.0	—
Senior unsecured notes	5,277.9	5,088.9	—	5,088.9	—
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 14 – 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 had a contingent consideration liability related to the Permian Acquisition, which was carried at fair value. See Note 4 – Joint Ventures, Acquisitions and Divestitures.

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 December 31, 2019, we had nine commodity swap and option contracts categorized as Level 3. The significant unobservable inputs used in the fair value measurements of our Level 3 derivatives are (i) the forward natural gas liquids pricing curves, for which a significant portion of the derivative's term is beyond available forward pricing and (ii) implied volatilities, which are unobservable as a result of inactive natural gas liquids options trading. The change in the fair value of Level 3 derivatives associated with a 10% change in the forward basis curve where prices are not observable is immaterial.

The fair value of the Permian Acquisition contingent consideration was determined using a Monte Carlo simulation model. Significant inputs used in the fair value measurement include expected gross margin (calculated in accordance with the terms of the purchase and sale agreements), term of the earn-out period, risk adjusted discount rate and volatility associated with the underlying assets. A significant decrease in expected gross margin during the earn-out period, or significant increase in the discount rate or volatility would have resulted in a lower fair value estimate.

The fair value of the TPL contingent consideration was determined using a probability-based model measuring the likelihood of meeting certain volumetric measures. The inputs for both models are not observable; therefore, the entire valuations of the contingent considerations are categorized in Level 3. The Permian Acquisition contingent consideration earn-out period ended on February 28, 2019 and resulted in a $317.1 million payment in May 2019. See Note 9 – Accounts Payable and Accrued Liabilities for additional discussion of the Permian Acquisition contingent consideration. 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)
Change in fair value of TPL contingent consideration	—	0.1
Completion of Permian Acquisition contingent consideration earn-out period	—	308.2
New Level 3 derivative instruments	(0.7)	—
Transfers out of Level 3 (1)	(6.5)	—
Unrealized gain/(loss) included in OCI	0.4	—
Balance, December 31, 2019	$ (0.3)	$ (2.3)

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

Note 16 — Related Party Transactions

Transactions with Unconsolidated Affiliates

The following table summarizes transactions with unconsolidated affiliates:

	GCF	T2 Joint Ventures	Cayenne	GCX	Little Missouri 4	Agua Blanca	Total
2019:							
Revenues	$ 0.3	$ 3.7	$ —	$ 0.8	$ 6.3	$ —	$ 11.0
Product purchases	(7.9)	—	(7.9)	(24.7)	—	—	(40.5)
Operating expenses	—	(2.0)	(0.2)	—	—	(1.2)	(3.4)
General and administrative expenses	—	—	—	—	(0.3)	—	(0.3)
2018:							
Revenues	$ 0.3	$ 5.2	$ —	$ 0.1	$ —	$ —	$ 5.6
Product purchases	(5.1)	(0.6)	(7.2)	(1.2)	—	—	(14.1)
Operating expenses	—	(3.6)	—	—	—	—	(3.6)
2017:							
Revenues	$ 0.3	$ 2.1	$ —	$ —	$ —	$ —	$ 2.4
Product purchases	(4.4)	(1.1)	—	—	—	—	(5.5)
Operating expenses	—	(3.8)	—	—	—	—	(3.8)

Relationship with Targa

We do not have any employees. Targa provides operational, general and administrative and other services to us associated with our existing assets and assets acquired from third parties. Targa performs centralized corporate functions for us, such as legal, accounting, treasury, insurance, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes, engineering and marketing.

Our Partnership Agreement governs the reimbursement of costs incurred by Targa on behalf of us. Targa charges us for all the direct costs of the employees assigned to our operations, as well as all general and administrative support costs other than (1) costs attributable to Targa's status as a separate reporting company and (2) until March 2018, costs of Targa providing management and support services to certain unaffiliated spun-off entities. We generally reimburse Targa monthly for cost allocations to the extent that Targa has made a cash outlay.

The following table summarizes transactions with Targa. Management believes these transactions are executed on terms that are fair and reasonable.

	Year Ended December 31, 2019	2018	2017
Targa billings of payroll and related costs included in operating expenses	$ 248.8	$ 236.8	$ 204.4
Targa allocation of general and administrative expense	237.2	221.4	175.2
Cash distributions to Targa based on general partner and limited partner ownership	1,152.4	918.5	847.3
Cash contributions from Targa related to limited partner ownership (1)	196.0	588.1	1,685.5
Cash contributions from Targa to maintain its 2% general partner ownership	4.0	12.0	34.5

(1) The cash contributions from Targa related to limited partner ownership were allocated 98% to the limited partner and 2% to the general partner. See Note 13 – Partnership Units and Related Matters.

Relationship with Sajet Resources LLC

In December 2010, immediately prior to Targa's initial public offering, Sajet Resources LLC ("Sajet") was spun-off from Targa. At the time, Rene Joyce, James Whalen and Joe Bob Perkins, directors of Targa, were also directors of Sajet. Joe Bob Perkins, James Whalen, Michael Heim, Jeffrey McParland, Paul Chung, and Matthew Meloy, executive officers of Targa at the time, were also executive officers of Sajet. The current directors of Sajet are Paul Chung, Jennifer Kneale, Chris McEwan and Matthew Meloy. The current executive officers of Sajet are Joe Bob Perkins, Matthew Meloy, Robert Muraro, Jennifer Kneale, Paul Chung and Julie Boushka. The primary assets of Sajet are real property. Sajet also holds (i) an ownership interest in Floridian Natural Gas Storage Company, LLC through a December 2016 merger with Tesla Resources LLC and (ii) an ownership interest in Allied CNG Ventures LLC. Former holders of our pre-IPO common equity, including certain of our current and former executives, managers and directors collectively own an 18% interest in Sajet. We provided general and administrative services to Sajet and were reimbursed for these amounts at our actual cost. Fees for services provided to Sajet totaled less than $0.1 million in January and February of 2018 and $0.3 million in the year ended December 31, 2017.

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

We hold three outstanding promissory notes from Sajet in the amounts of $9.9 million, $0.5 million and $0.2 million. The interest rate on each of the promissory notes accrues at the prime rate plus six percent annum. Since March 2018, Sajet has been accounted for on a consolidated basis in our consolidated financial statements.

Note 17 — Commitments

Future non-cancelable commitments related to certain contractual obligations are presented below for each of the next five fiscal years and in aggregate thereafter:

	In Aggregate	2020	2021	2022	2023	2024	Thereafter
Land sites and rights of way (1)	$ 150.4	$ 3.8	$ 4.0	$ 4.4	$ 4.3	$ 4.5	$ 129.4

(1) Land site lease and rights of way provides for surface and underground access for gathering, processing and distribution assets that are located on property not owned by us. These agreements expire at various dates, with varying terms, some of which are perpetual.

Total expenses incurred under the above non-cancelable commitments were:

	2019	2018	2017
Land sites and rights of way	$ 6.1	$ 6.1	$ 5.2

Note 18 – Contingencies

Legal Proceedings

We are a party to various legal, administrative and regulatory proceedings that have arisen in the ordinary course of our business. We are also a party to various proceedings with governmental environmental agencies, 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 monetary sanctions 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.

Note 19 — Significant Risks and Uncertainties

Nature of Our Operations in Midstream Energy Industry

We operate in the midstream energy industry. Our business activities include gathering, processing, transporting, fractionating and storage of natural gas, NGLs and crude oil. Our results of operations, cash flows and financial condition may be affected by changes in the commodity prices of these hydrocarbon products and changes in the relative price levels among these hydrocarbon products. In general, the prices of natural gas, NGLs, condensate and other hydrocarbon products are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control.

Our profitability could be impacted by a decline in the volume of crude oil, natural gas, NGLs and condensate transported, gathered or processed at our facilities. A material decrease in natural gas or condensate production or condensate refining, as a result of depressed commodity prices, a decrease in exploration and development activities, or otherwise, could result in a decline in the volume of crude oil, natural gas, NGLs and condensate handled by our facilities.

A reduction in demand for NGL products by the petrochemical, refining or heating industries, whether because of (i) general economic conditions, (ii) reduced demand by consumers for the end products made with NGL products, (iii) increased competition from petroleum-based products due to the pricing differences, (iv) adverse weather conditions, (v) government regulations affecting commodity prices and production levels of hydrocarbons or the content of motor gasoline or (vi) other reasons, could also adversely affect our results of operations, cash flows and financial position.

Our principal market risks are exposure to changes in commodity prices, particularly to the prices of natural gas, NGLs and crude oil, and changes in interest rates.

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 commodities 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. In response to these price risks, we monitor NGL inventory levels in order to mitigate losses related to downward price exposure.

In an effort to reduce the variability of our cash flows, we have entered into derivative financial instruments to hedge the commodity price associated with a significant portion of our expected natural gas, NGL and condensate equity volumes, future commodity purchases and sales, and transportation basis risk. Historically, these transactions have included both swaps and purchased puts (or floors) and calls (or caps) to hedge additional expected equity commodity volumes without creating volumetric risk. We hedge a higher percentage of our expected equity volumes in the earlier future periods. With swaps, we typically receive an agreed upon fixed price for a specified notional quantity and 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 actual equity volumes, we limit our use of swaps to hedge the prices of less than our expected equity volumes. Our commodity hedges may expose us to the risk of financial loss in certain circumstances.

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, NGL and crude oil prices.

Counterparty Risk – Credit and Concentration

Derivative Counterparty Risk

Where we are exposed to credit risk in our financial instrument transactions, management analyzes the counterparty’s financial condition prior to entering into an agreement, establishes credit and/or margin limits and monitors the appropriateness of these limits on an ongoing basis. Generally, management does not require collateral and does not anticipate nonperformance by our counterparties.

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, which reduced our maximum loss due to counterparty credit risk by $21.0 million as of December 31, 2019. The range of losses attributable to our individual counterparties would be between $0.2 million and $21.8 million, depending on the counterparty in default.

The credit exposure related to commodity derivative instruments is represented by the fair value of contracts with a net positive fair value, representing expected future receipts, at the reporting date. At such times, these outstanding instruments expose us to losses in the event of nonperformance by the counterparties to the agreements. Should the creditworthiness of one or more of the counterparties decline, the 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.

Customer Credit Risk

We extend credit to customers and other parties in the normal course of business. We have established various procedures to manage our credit exposure, including initial credit approvals, credit limits and terms, letters of credit, and rights of offset. We also use prepayments and guarantees to limit credit risk to ensure that our established credit criteria are met. Our allowance for doubtful accounts was $0.0 million as of December 31, 2019 and $0.1 million as of December 31, 2018.

Significant Commercial Relationship

During the years ended December 31, 2019 and 2018, sales of commodities and fees from midstream services provided to Petredec (Europe) Limited comprised approximately 12% and 15% of our consolidated revenues. No customer comprised greater than 10% of our consolidated revenues in the year ended December 31, 2017.

Interest Rate Risk

We are exposed to changes in interest rates, primarily as a result of variable rate borrowings under the TRP Revolver and the Securitization Facility.

Casualty or Other Risks

Targa maintains coverage in various insurance programs on our behalf, which provides us with property damage, business interruption and other coverage which is customary for the nature and scope of our operations. The majority of the insurance costs described above is allocated to us by Targa through the Partnership Agreement described in Note 16 – Related Party Transactions.

Management believes that Targa has adequate insurance coverage, although insurance may not cover every type of interruption that might occur. As a result of insurance market conditions, premiums and deductibles may change overtime, and in some instances, certain insurance may become unavailable, or available for only reduced amounts of coverage. As a result, Targa may not be able to renew existing insurance policies or procure other desirable insurance on commercially reasonable terms, if at all.

If we were to incur a significant liability for which we were not fully insured, it could have a material impact on our consolidated financial position and results of operations. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur. Any event that interrupts the revenues generated by us, or which causes us to make significant expenditures not covered by insurance, could reduce our ability to meet our financial obligations. Furthermore, even when a business interruption event is covered, it could affect interperiod results as we would not recognize the contingent gain until realized in a period following the incident.

Note 20 – 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.

	2020	2021	2022 and after
Fixed consideration to be recognized as of December 31, 2019	$ 495.1	$ 500.0	$ 3,209.8

In accordance with the optional exemptions that we elected to apply, the amounts presented in the table exclude variable consideration for which the allocation exception is met and consideration associated with performance obligations of short-term contracts. In addition, consideration from contracts for which we recognize revenue at the amount to which we have the right to invoice for services performed is also excluded from the table above, with the exception of any fixed consideration attributable to such contracts. The nature of the performance obligations for which the consideration has been excluded is consistent with the performance obligations described within our revenue recognition accounting policy and the estimated remaining duration of such contracts primarily ranges from 1 to 19 years. In addition, variability exists in the consideration excluded due to the unknown quantity and composition of volumes to be serviced or sold as well as fluctuations in the market price of commodities to be received as consideration or sold over the applicable remaining contract terms. Such variability is resolved at the end of each future month or quarter.

For additional information on our revenue recognition policy, see Note 3 – Significant Accounting Policies. For disclosures related to disaggregated revenue, see Note 25 – Segment Information.

Note 21 — Other Operating (Income) Expense

Other Operating (Income) Expense is comprised of the following:

	Year Ended December 31,		
	2019	2018	2017
(Gain) loss on sale of disposition of business and assets	$ 71.1	$ (0.1)	$ 15.9
Miscellaneous business tax	0.2	3.2	0.8
Other	—	0.4	0.7
	$ 71.3	$ 3.5	$ 17.4

The (Gain) loss on sale or disposal of business and assets is comprised of the following:

	Year Ended December 31,		
	2019	2018	2017
Delaware crude gathering - held for sale	$ 59.5	$ —	$ —
Sale of inland marine barge business	—	(48.1)	—
Exchange of a portion of Versado gathering system	—	(44.4)	—
Sale of storage and terminaling facilities	—	59.1	—
Disposal of benzene treating unit	—	20.5	—
Sale of Venice gathering system	—	—	16.1
Other	11.6	12.8	(0.2)
	$ 71.1	$ (0.1)	$ 15.9

Note 22 – Income Tax

Our income tax expense (benefit) is summarized below:

	2019	2018	2017
Current expense (benefit)	$ —	$ —	$ (4.5)
Deferred expense (benefit)	(0.9)	(0.1)	(2.9)
Total income tax expense (benefit)	$ (0.9)	$ (0.1)	$ (7.4)

TPL Arkoma Inc., a corporate subsidiary of the Partnership, is subject to federal and state income tax. The Partnership's corporate subsidiary accounts for income taxes under the asset and liability method and provides deferred income taxes for all significant temporary differences.

On December 22, 2017, the U.S. government enacted comprehensive tax legislation commonly referred to as the Tax Cuts and Jobs Act (the "Tax Act"), which significantly changed United States corporate income tax laws beginning, generally, in 2018. These changes included, among others, (1) a permanent reduction of the United States corporate income tax rate from a top marginal rate of 35% to a flat rate of 21%; (2) elimination of the corporate alternative minimum tax ("AMT"); (3) immediate deductions for certain new investments instead of deductions for depreciation expense over time, (4) limitation on the tax deduction for interest expense to 30% of adjusted taxable income; (5) limitation of the deduction for net operating losses to 80% of current year taxable income and elimination of net operating loss carrybacks; and (6) elimination of many business deductions and credits, including the domestic production activities deduction, and the deduction for entertainment expenditures

The SEC staff issued Staff Accounting Bulletin No. 118 (“SAB 118”), which provides guidance on accounting for the tax effects of the Tax Act. SAB 118 provides a measurement period that should not extend beyond one year from the Tax Act enactment date for companies to complete the accounting under ASC 740. In accordance with SAB 118, a company must reflect the income tax effects of those aspects of the Tax Act for which the accounting under ASC 740 is complete. To the extent that a company's accounting for certain income tax effects of the Tax Act is incomplete but it is able to determine a reasonable estimate, it must record a provisional estimate in the financial statements. If a company cannot determine a provisional estimate to be included in the financial statements, it should continue to apply ASC 740 on the basis of the provisions of the tax laws that were in effect immediately before the enactment of the Tax Act. We completed the accounting for the 2017 provisional items in 2018 as outlined below:

Our accounting for all applicable elements of the Tax Act is complete:

- We reclassified $0.3 million of AMT credits from deferred tax assets to long term assets. We expect to receive this amount as a refund in 2019-2021. We received $0.2 million of the refund in 2019.
- The Tax Act reduces the corporate tax rate to 21%, effective January 1, 2018. We recorded a provisional deferred tax benefit of $1.0 million for the year ended December 31, 2017.
- In the year ended December 31, 2017, we recorded a provisional tax depreciation expense of $0.7 million, which did not include full expensing of all qualifying capital expenditures. In the year ended December 31, 2018, we completed our analysis of capital expenditures and recorded no additional expenditures.

Prior to the TRC/TRP Merger, the Partnership was subject to the Texas margin tax, consisting generally of a 0.75% tax on the amounts by which total revenues exceed cost of goods sold, as apportioned to Texas. After the TRC/TRP Merger, TRC is the reporting company for the combined group. The Partnership still has audit responsibility for the pre-Merger years.

Our deferred income tax assets and liabilities at December 31, 2019 and 2018, consisted of differences related to the timing of recognition of certain types of costs as follows:

	2019	2018
Deferred tax assets:		
Net operating loss carryforwards	$ 13.4	$ 12.9
Deferred tax liabilities:		
Property, plant, and equipment	(36.4)	(36.8)
Net deferred tax asset (liability)	$ (23.0)	$ (23.9)

As of December 31, 2019, TPL Arkoma, Inc. had net operating loss carry forwards for federal income tax purposes of approximately $51.7 million, which expire at various dates from 2029 to 2039. Management believes it more likely than not that the deferred tax asset will be fully utilized.

Note 23 — Supplemental Cash Flow Information

	Year Ended December 31, 2019	2018	2017
Cash:			
Interest paid, net of capitalized interest (1)	$ 271.5	$ 203.2	$ 198.7
Income taxes paid, net of refunds	(1.8)	0.2	(4.9)
Non-cash investing activities:			
Deadstock commodity inventory transferred to property, plant and equipment	$ 21.8	$ 49.0	$ 9.0
Impact of capital expenditure accruals on property, plant and equipment	(193.9)	216.9	205.4
Transfers from materials and supplies inventory to property, plant and equipment	25.1	12.7	3.6
Contribution of property, plant and equipment to investments in unconsolidated affiliates	—	16.0	1.0
Change in ARO liability and property, plant and equipment due to revised cash flow estimate and additions	6.7	1.8	3.9
Property, plant and equipment received in asset exchange	—	24.1	—
Receivable for asset exchange	—	15.0	—
Asset received related to conveyance of ownership interest in investment in unconsolidated affiliate	—	3.0	—
Non-cash financing activities:			
Accrued distributions to noncontrolling interests	$ 91.7	$ —	$ —
Non-cash balance sheet movements related to assets held for sale (See Note 4 - Joint Ventures, Acquisitions and Divestitures):			
Trade receivables	$ 6.9	$ —	$ —
Intangible assets, net accumulated amortization and estimated loss on sale	52.1	—	—
Goodwill	1.4	—	—
Property, plant and equipment, net of accumulated depreciation and estimated loss on sale	77.3	—	—
Accounts payable and accrued liabilities	6.2	—	—
Other long-term obligations	0.2	—	—
Non-cash balance sheet movements related to the Permian Acquisition - See Note 4 - Joint Ventures, Acquisitions and Divestitures):			
Contingent consideration recorded at the acquisition date	$ —	$ —	$ 416.3
Lease liabilities arising from recognition of right-of-use assets:			
Operating lease	$ 6.9	$ —	$ —
Finance lease	10.1	—	—

(1) Interest capitalized on major projects was $61.8 million, $46.3 million and $14.3 million for the years ended December 31, 2019, 2018 and 2017.

Note 24 — Compensation Plans

TRC Equity Compensation Plan

In connection with the TRC/TRP Merger, TRC adopted and assumed our Long-term Incentive Plan and outstanding awards thereunder, and amended and restated the plan and renamed it the Targa Resources Corp. Equity Compensation Plan (the “Plan”). TRC continued to maintain the Equity Compensation Plan during 2017. However, since the number of shares reserved under the Equity Compensation Plan had been substantially exhausted as of the end of 2016, TRC no longer made grants under the Plan, which terminated in February 2017.

The restricted stock units (“RSUs”) remaining under this Plan are the converted TRP awards and the RSUs made in lieu of cash bonus for our nonexecutives.

The following table summarizes the RSUs for the year ended December 31, 2019, under the Plan:

	Number of shares	Weighted Average Grant-Date Fair Value
Outstanding as of December 31, 2018	301,691	$ 27.10
Vested	(294,237)	26.48
Outstanding as of December 31, 2019	7,454	51.49

TRC Long Term Incentive Plan

The TRC LTIP is administered by the Compensation Committee of the Targa board of directors. Prior to the TRC/TRP Merger, the TRC LTIP provided for the grant of cash-settled performance units only. In connection with the TRC/TRP Merger, performance unit grant agreements were amended to convert TRP's outstanding cash-settled performance unit obligation to cash-settled restricted stock units.

During 2018, the remaining 112,550 shares of cash-settled awards vested and we paid $6.9 million related to those awards.

Cash settled for the awards under TRC LTIP were $6.9 million and $4.1 million for 2018 and 2017.

2010 TRC Stock Incentive Plan

In December 2010, TRC adopted the Targa Resources Corp. 2010 Stock Incentive Plan for employees, consultants and non-employee directors of the Company. In May 2017, the 2010 TRC Plan was amended and restated (the "2010 TRC Plan"). Total authorized shares of common stock under the plan is 15,000,000, comprised of 5,000,000 shares originally available and an additional 10,000,000 shares that became available in May 2017. The 2010 TRC Plan allows for the grant of (i) incentive stock options qualified as such under U.S. federal income tax laws ("Incentive Options"), (ii) stock options that do not qualify as incentive options ("Non-statutory Options," and together with Incentive Options, "Options"), (iii) stock appreciation rights ("SARs") granted in conjunction with Options or Phantom Stock Awards, (iv) restricted stock awards ("Restricted Stock Awards"), (v) phantom stock awards ("Phantom Stock Awards"), (vi) bonus stock awards, (vii) performance unit awards, or (viii) any combination of such awards (collectively referred to as "Awards").

Unless otherwise specified, the compensation costs for the awards listed below were recognized as expenses over related vesting periods based on the grant-date fair values, reduced by forfeitures incurred.

Restricted Stock Awards - Restricted stock entitles the recipient to cash dividends. Dividends on unvested restricted stock will be accrued when declared and recorded as short-term or long-term liabilities, dependent on the time remaining until payment of the dividends, and paid in cash when the award vests. The restricted stock awards will be included in the outstanding shares of the common stock upon issuance.

Director Grants – The committee awarded TRC common stock to our outside directors. In 2019, 2018 and 2017, TRC issued 25,344, 16,955 and 13,818 shares of director grants with the weighted average grant-date fair value of $42.83, $51.21 and $60.48. Starting from January 1, 2018, director grants are restricted stock awards that vest in one year. In prior years, directors were granted shares of common stock with no vesting requirement.

Restricted Stock Units Awards – Restricted Stock Units ("RSUs") are similar to restricted stock, except that shares of common stock are not issued until the RSUs vest. The vesting periods vary from one year to six years. In 2019, 2018 and 2017, TRC issued 1,042,344, 1,393,812 and 1,193,942 shares of RSUs with the weighted average grant-date fair value of $39.95, $51.71 and $54.18. The 2019 and 2018 issuances include 85,547 and 275,076 shares of RSUs for our new retention program. These shares will vest in October 2022.

Restricted Stock in Lieu of Bonus – In 2019, 2018 and 2017, TRC issued 95,687, 112,438 and 84,221 shares of restricted stock awards in lieu of cash bonuses in the form of RSUs for our executives at the weighted average grant-date fair value of $42.83, $51.09 and $55.94. These awards will cliff vest over three years. Dividends on bonus awards issued after 2017 are paid quarterly.

The following table summarizes the restricted stock and RSUs under the 2010 TRC Plan in shares and in dollars for the year indicated.

	Number of shares	Weighted Average Grant-Date Fair Value
Outstanding at December 31, 2018	3,594,135	$ 45.31
Granted	1,067,688	40.02
Forfeited	(175,861)	51.90
Vested	(1,093,901)	28.31
Outstanding at December 31, 2019	3,392,061	48.79

Performance Share Units

During 2019, 2018 and 2017, TRC issued 261,245, 182,849 and 113,901 shares of performance share units ("PSUs") to executive management and employees for the 2019, 2018 and 2017 compensation cycle that will vest/have vested in January 2022, January 2021 and January 2020. The PSUs granted under the 2010 TRC Plan are three-year equity-settled awards linked to the performance of shares of the common stock. The awards also include dividend equivalent rights ("DERs") that are based on the notional dividends accumulated during the vesting period.

The vesting of the PSUs is dependent on the satisfaction of a combination of certain service-related conditions and the Company's total shareholder return ("TSR") relative to the TSR of the members of a specified comparator group of publicly-traded midstream companies (the "LTIP Peer Group") measured over designated periods. The TSR performance factor is determined by the Committee at the end of the overall performance period based on relative performance over the designated weighting periods as follows: (i) 25% based on annual relative TSR for the first year; (ii) 25% based on annual relative TSR for the second year; (iii) 25% based on annual relative TSR for the third year; and (iv) the remaining 25% based on cumulative three-year relative TSR over the entirety of the performance period. With respect to each weighting period, the Committee determines the "guideline performance percentage," which could range from 0% to 250%, based upon the Company's relative TSR performance for the applicable period. The TSR performance factor will be calculated by averaging the guideline performance percentage for each weighting period, and the average percentage may then be decreased or increased by the Committee at its discretion. The grantee will become vested in a number of PSUs equal to the target number awarded multiplied by the TSR performance factor, and vested PSUs will be settled by the issuance of Company common stock. The value of dividend equivalent rights will be paid in cash when the awards vest.

Compensation cost for equity-settled PSUs was recognized as an expense over the performance period based on fair value at the grant date. The compensation cost will be reduced if forfeitures occur. Fair value was calculated using a simulated share price that incorporates peer ranking. DERs associated with equity-settled PSUs were accrued over the performance period as a reduction of owners' equity. We evaluated the grant date fair value using a Monte Carlo simulation model and historical volatility assumption with an expected term of three years. The expected volatilities were 32% - 37% for PSUs granted in 2019, 29% - 53% for PSUs granted in 2018 and 55% - 61% for PSUs granted in 2017.

The following table summarizes the PSUs under the 2010 TRC Plan in shares and in dollars for the years indicated.

	Number of shares	Weighted Average Grant-Date Fair Value
Outstanding at December 31, 2018	296,750	$ 88.19
Granted	261,245	64.46
Forfeited	(29,276)	86.57
Outstanding at December 31, 2019	528,719	76.56

Cash-settled Awards

During 2019 and 2018, TRC issued 7,836 and 69,042 shares of cash-settled awards for our retention program. These awards are liability awards and vest each quarter for one year. The fair value of the awards is evaluated based on the average of TRC stock prices for the last ten trading days at the end of each quarter. All cash-settled awards vested in 2019. Payments for the cash-settled awards are classified within operating activities in the Consolidated Statements of Cash Flows. The following table summarizes the cash-settled restricted stock units for the year ended 2019.

	Number of shares
Outstanding as of December 31, 2018	50,228
Granted	7,836
Vested and paid	(54,313)
Forfeited	(3,672)
Outstanding as of December 31, 2019	79

We made $2.9 million in payments for the cash-settled restricted units during 2019 and no payments in 2018.

Stock compensation expense under the plans totaled $61.8 million, $59.0 million, and $44.2 million for the years ended December 31, 2019, 2018, and 2017.

As of December 31, 2019, we have $97.7 million of unrecognized compensation expense associated with share-based awards and an approximate remaining weighted average vesting periods of 2.2 years related to our various compensation plans.

The fair values of share-based awards vested in 2019, 2018 and 2017 were $55.4 million, $18.8 million and $14.4 million. Cash dividends paid for the vested awards were $15.0 million, $3.5 million and $2.5 million for 2019, 2018 and 2017.

Subsequent Events

In January 2020, the Compensation Committee of the Targa board of directors made the following awards under the 2010 TRC Plan.

- 29,472 shares of restricted stock to our outside directors that will vest in January 2021.
- 283,015 shares of RSUs to executive management for the 2020 compensation cycle that will vest in January 2023.
- 283,015 shares of PSUs to executive management for the 2020 compensation cycle that will vest in January 2023.
- 81,336 shares of RSUs in lieu of cash bonus to one executive for the 2020 compensation cycle that will vest in January 2021.

In January 2020, 25,344 shares of director grants vested with no shares withheld to satisfy tax withholding obligations.
In January 2020, 121,239 shares of 2017 PSUs vested with 30,804 shares withheld to satisfy tax withholding obligations.
In January 2020, total 111,808 shares of RSUs vested with 29,199 shares withheld to satisfy tax withholding obligations.

Note 25 — Segment Information

We operate in two primary segments: (i) Gathering and Processing, and (ii) Logistics and Transportation (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.

In the fourth quarter of 2019, we made the following changes to the presentation of our reportable segments:

- Renamed the Logistics and Marketing segment as Logistics and Transportation. The updated name better describes the business composition and activity of the segment given the recent completion of Grand Prix. The change in naming convention did not impact previously reported results for the segment. This segment is also referred to as the Downstream Business.

- Due to changes in how our executive team evaluates segment performance, results of commodity derivative activities related to our equity volume hedges that are designated as accounting hedges are now reported in the Gathering and Processing segment. These hedge activities were previously reported in Other. Our prior period segment information has been updated to reflect the change. There was no impact to our Consolidated Statements of Operations.

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, Central 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 (including the Bakken and Three Forks plays); and the onshore and near offshore regions of the Louisiana Gulf Coast and the Gulf of Mexico.

Our Logistics and Transportation 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 transporting, storing, fractionating, terminaling and marketing of NGLs and NGL products, including services to LPG exporters; and certain natural gas supply and marketing activities in support of our other businesses. The associated assets are generally connected to and supplied in part by our Gathering and Processing segment and, except for pipelines and smaller terminals, are located predominantly in Mont Belvieu and Galena Park, Texas, and in Lake Charles, Louisiana.

Other contains the 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:

	Year Ended December 31, 2019				
	Gathering and Processing	Logistics and Transportation	Other	Corporate and Eliminations	Total
Revenues					
Sales of commodities	$ 1,101.6	$ 6,406.1	$ (113.9)	$ —	$ 7,393.8
Fees from midstream services	728.0	549.3	—	—	1,277.3
	1,829.6	6,955.4	(113.9)	—	8,671.1
Intersegment revenues					
Sales of commodities	2,628.4	132.2	—	(2,760.6)	—
Fees from midstream services	7.4	28.7	—	(36.1)	—
	2,635.8	160.9	—	(2,796.7)	—
Revenues	$ 4,465.4	$ 7,116.3	$ (113.9)	$ (2,796.7)	$ 8,671.1
Operating margin	$ 1,006.5	$ 867.2	$ (113.9)	$ —	$ 1,759.8
Other financial information:					
Total assets (1)	$ 11,929.8	$ 6,741.8	$ 1.0	$ 71.9	$ 18,744.5
Goodwill	$ 45.2	$ —	$ —	$ —	$ 45.2
Capital expenditures	$ 1,273.3	$ 1,412.2	$ —	$ 23.5	$ 2,709.0

(1) Assets in the Corporate and Eliminations column primarily include cash, prepaids and debt issuance costs for our TRP Revolver.

	Year Ended December 31, 2018				
	Gathering and Processing	Logistics and Transportation	Other	Corporate and Eliminations	Total
Revenues					
Sales of commodities	$ 1,228.2	$ 8,058.4	$ (7.9)	$ —	$ 9,278.7
Fees from midstream services	715.6	489.7	—	—	1,205.3
	1,943.8	8,548.1	(7.9)	—	10,484.0
Intersegment revenues					
Sales of commodities	3,636.0	317.1	—	(3,953.1)	—
Fees from midstream services	7.2	30.8	—	(38.0)	—
	3,643.2	347.9	—	(3,991.1)	—
Revenues	$ 5,587.0	$ 8,896.0	$ (7.9)	$ (3,991.1)	$ 10,484.0
Operating margin	$ 939.2	$ 592.5	$ (7.9)	$ —	$ 1,523.8
Other financial information:					
Total assets (1)	$ 11,602.7	$ 5,180.6	$ 3.2	$ 103.6	$ 16,890.1
Goodwill	$ 46.6	$ —	$ —	$ —	$ 46.6
Capital expenditures	$ 1,548.6	$ 1,767.0	$ —	$ 12.1	$ 3,327.7

(1) Assets in the Corporate and Eliminations column primarily include cash, prepaids and debt issuance costs for our TRP Revolver.

	Year Ended December 31, 2017				
	Gathering and Processing	Logistics and Transportation	Other	Corporate and Eliminations	Total
Revenues					
Sales of commodities	$ 774.0	$ 6,979.3	$ (2.2)	$ —	$ 7,751.1
Fees from midstream services	566.3	497.5	—	—	1,063.8
	1,340.3	7,476.8	(2.2)	—	8,814.9
Intersegment revenues					
Sales of commodities	3,154.2	321.9	—	(3,476.1)	—
Fees from midstream services	6.9	28.0	—	(34.9)	—
	3,161.1	349.9	—	(3,511.0)	—
Revenues	$ 4,501.4	$ 7,826.7	$ (2.2)	$ (3,511.0)	$ 8,814.9
Operating margin	$ 776.4	$ 511.8	$ (2.2)	$ —	$ 1,286.0
Other financial information:					
Total assets (1)	$ 10,787.7	$ 3,507.4	$ 1.4	$ 62.5	$ 14,359.0
Goodwill	$ 256.6	$ —	$ —	$ —	$ 256.6
Capital expenditures	$ 1,008.9	$ 470.4	$ —	$ 27.2	$ 1,506.5
Business acquisitions	$ 987.1	$ —	$ —	$ —	$ 987.1

(1) Assets in the Corporate and Eliminations column primarily include cash, prepaids and debt issuance costs for our TRP Revolver.

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

	2019	2018	2017
Sales of commodities:			
Revenue recognized from contracts with customers:			
Natural gas	$ 1,321.7	$ 1,810.0	$ 2,005.9
NGL	5,233.8	6,886.9	5,454.2
Condensate and crude oil	716.1	457.9	196.0
Petroleum products	126.3	196.1	144.7
	7,397.9	9,350.9	7,800.8
Non-customer revenue:			
Derivative activities - Hedge	138.0	(39.7)	(44.7)
Derivative activities - Non-hedge (1)	(142.1)	(32.5)	(5.0)
	(4.1)	(72.2)	(49.7)
Total sales of commodities	7,393.8	9,278.7	7,751.1
Fees from midstream services:			
Revenue recognized from contracts with customers:			
Gathering and processing	722.4	698.1	523.3
NGL transportation, fractionation and services	169.4	154.6	170.7
Storage, terminaling and export	356.4	313.0	300.8
Other	29.1	39.6	69.0
Total fees from midstream services	1,277.3	1,205.3	1,063.8
Total revenues	$ 8,671.1	$ 10,484.0	$ 8,814.9

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

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

	2019	2018	2017
Reconciliation of reportable segment operating margin to income (loss) before income taxes:			
Gathering and Processing operating margin	$ 1,006.5	$ 939.2	$ 776.4
Logistics and Transportation operating margin	867.2	592.5	511.8
Other operating margin	(113.9)	(7.9)	(2.2)
Depreciation and amortization expense	(971.7)	(815.9)	(809.5)
General and administrative expense	(267.5)	(240.8)	(190.5)
Impairment of property, plant and equipment	(243.2)	—	(378.0)
Impairment of goodwill	—	(210.0)	—
Interest expense, net	(320.8)	(170.0)	(217.8)
Equity earnings (loss)	39.0	7.3	(17.0)
Gain (loss) on sale or disposition of business and assets	(71.1)	0.1	(15.9)
Gain (loss) from sale of equity-method investment	69.3	—	—
Gain (loss) from financing activities	(1.4)	(1.3)	(10.9)
Change in contingent considerations	(8.7)	8.8	99.6
Other, net	(0.2)	(3.5)	(4.0)
Income (loss) before income taxes	$ (16.5)	$ 98.5	$ (258.0)

Note 26 — Selected Quarterly Financial Data (Unaudited)

Our results of operations by quarter for the years ended December 31, 2019 and 2018 were as follows:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2019					
Revenues	$ 2,299.4	$ 1,995.3	$ 1,902.5	$ 2,473.9	$ 8,671.1
Gross margin	573.4	633.7	574.4	$ 771.1	$ 2,552.6
Income (loss) from operations (1)	64.7	117.2	45.9	$ (21.7)	$ 206.1
Net income (loss)	(19.0)	51.7	37.5	$ (85.8)	$ (15.6)
Net income (loss) attributable to common limited partners	(32.5)	(7.3)	(41.0)	$ (179.9)	$ (260.7)
2018					
Revenues	$ 2,455.6	$ 2,444.4	$ 2,986.4	$ 2,597.6	$ 10,484.0
Gross margin	514.6	539.1	602.9	589.2	2,245.8
Income (loss) from operations (2)	90.4	159.2	80.6	(76.6)	253.6
Net income (loss)	56.0	162.6	(8.7)	(111.3)	98.6
Net income (loss) attributable to common limited partners	39.2	147.6	(20.8)	(127.1)	38.9

(1) Includes a non-cash pre-tax impairment charge of $229.0 million in the fourth quarter of 2019. See Note 6 — Property, Plant and Equipment and Intangible Assets.

(2) Includes a non-cash pre-tax impairment charge of $210.0 million in the fourth quarter of 2018. See Note 7 – Goodwill.

Exhibit 4.53

DESCRIPTION OF REGISTRANT'S SECURITIES REGISTERED PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934

The following description of preferred units of Targa Resources Partners LP (the "Partnership", "we," "us," and "our") does not purport to be complete and is qualified in its entirety by reference to the provisions of applicable law and to our Third Amended and Restated Agreement of Limited Partnership, as amended (the "Partnership Agreement"). References to our "general partner" refer to Targa Resources GP LLC, our general partner.

Series A Preferred Units

Our 9.00% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Series A Preferred Units") entitle the holders thereof to receive cumulative cash distributions when, as and if declared by the board of directors of our general partner out of legally available funds for such purpose. The Series A Preferred Units are fully paid and nonassessable. Subject to the matters described under "Liquidation Rights," each Series A Preferred Unit generally has a fixed liquidation preference of $25.00 per unit plus an amount equal to accumulated and unpaid distributions thereon to the date fixed for payment, whether or not declared.

The Series A Preferred Units represent perpetual equity interests in us and, unlike our indebtedness, do not give rise to a claim for redemption at a particular date. As such, the Series A Preferred Units rank junior to all of our existing and future indebtedness (including (i) indebtedness outstanding under our senior secured credit facility, (ii) our senior notes and (iii) indebtedness outstanding under our securitization facility) and other liabilities with respect to assets available to satisfy claims against us. The rights of holders of Series A Preferred Units to receive the liquidation preference are subject to the proportional rights of holders of any class or series of partnership interests or other equity securities established after the original issue date of the Series A Preferred Units that is not expressly made senior or subordinated to the Series A Preferred Units as to the payment of non-liquidating distributions (the "Parity Securities").

All of the Series A Preferred Units are represented by one or more certificates issued to The Depository Trust Company (and its successors or assigns or any other securities depositary selected by us) (the "Depositary") and registered in the name of its nominee and, so long as a Depositary has been appointed and is serving, no person acquiring Series A Preferred Units is entitled to receive a certificate representing such units unless applicable law otherwise requires or the Depositary gives notice of its intention to resign or is no longer eligible to act as such and a successor is not appointed within 60 days thereafter.

Except as described below in "Change of Control — Change of Control Rights," the Series A Preferred Units are not convertible into our common units or any other securities and do not have exchange rights and are not entitled or subject to any preemptive or similar rights. The Series A Preferred Units are not subject to mandatory redemption or to any sinking fund requirements. The Series A Preferred Units will be subject to redemption, in whole or in part, at our option commencing on November 1, 2020. Please read "Redemption."

We have appointed Computershare Trust Company, N.A. as the paying agent (the "Paying Agent"), and the registrar and transfer agent (the "Transfer Agent") for the Series A Preferred Units. The address of the Paying Agent and the Transfer Agent is P.O. Box 43010, Providence, Rhode Island 02940-3010.

The Series A Preferred Units are listed on the New York Stock Exchange under the symbol "NGLS/PA." As of February 20, 2020, we had 5,000,000 Series A Preferred Units issued and outstanding.

Ranking

The Series A Preferred Units, with respect to anticipated monthly distributions, rank:

- senior to our common units and to each other class or series of partnership interests or other equity securities established after the original issue date of the Series A Preferred Units that is not expressly made senior to or pari passu with the Series A Preferred Units as to the payment of nonliquidating distributions (the "Junior Securities");

- pari passu with any Parity Securities;
- junior to all of our existing and future indebtedness (including (i) indebtedness outstanding under our senior secured credit facility, (ii) our existing senior notes and (iii) indebtedness outstanding under our securitization facility) and other liabilities with respect to assets available to satisfy claims against us; and
- junior to each other class or series of partnership interests or other equity securities established after the original issue date of the Series A Preferred Units that is expressly made senior to the Series A Preferred Units as to the payment of nonliquidating distributions (the "Senior Securities").

Under our Partnership Agreement, we may issue Junior Securities from time to time in one or more series without the consent of the holders of the Series A Preferred Units. The board of directors of our general partner has the authority to determine the preferences, powers, qualifications, limitations, restrictions and special or relative rights or privileges, if any, of any such series before the issuance of any units of that series. The board of directors of our general partner will also determine the number of units constituting each series of securities. Our ability to issue any Parity Securities in certain circumstances or Senior Securities is limited as described under "Voting Rights."

Change of Control

Redemption upon a Change of Control

Upon a Change of Control (as defined under our Partnership Agreement), we (or a third party with our prior written consent) may, within 120 days after the first date on which such Change of Control occurred, subject to applicable law, redeem the Series A Preferred Units, in whole or in part, from any source of funds legally available for such purpose, by paying $25.00 per Series A Preferred Unit, plus all accumulated and unpaid distributions (whether or not such distributions will have been declared) to the redemption date. If, prior to the Change of Control Conversion Date (as defined below), we exercise (or a third party with our prior written consent exercises) these redemption rights described in the immediately preceding sentence or as described below under "Redemption" by giving written notice of redemption, holders of the Series A Preferred Units that we have (or a third party with our prior written consent has) elected to redeem will not have the conversion right described below under "—Change of Control Rights." Any such redemption by the Partnership will be subject to compliance with the provisions of our senior secured credit facility, the indentures governing our outstanding senior notes and any other agreements governing our future or existing outstanding indebtedness.

Any such redemption will be subject to the redemption procedures described below under "Redemption—Redemption Procedures."

Change of Control Rights

Upon the occurrence of a Change of Control that occurs while Series A Preferred Units are outstanding, each holder of Series A Preferred Units will have the right to convert (a "Series A Change of Control Conversion") such number of Series A Preferred Units held by such holder on the Change of Control Conversion Date (as defined below) as such holder may elect into a number of our common units per Series A Preferred Unit to be converted (such number of common units, the "Common Unit Conversion Consideration") equal to, subject to certain adjustments pursuant to our Partnership Agreement, the lesser of:

- the quotient obtained by dividing (i) the sum of the $25.00 liquidation preference plus the amount of any accumulated and unpaid distributions to the Change of Control Conversion Date (unless the Change of Control Conversion Date is after a record date for a Series A Preferred Unit distribution payment and prior to the corresponding Series A Preferred Unit distribution payment date, in which case no additional amount for such accumulated and unpaid distribution will be included in this sum) by (ii) the average of the closing prices for our common units on the National Securities Exchange (as defined below) on which our common units are then listed or admitted to trading for the ten consecutive trading days ending with the trading day immediately preceding the Change of Control Conversion Date, and
- 1.54607 (the "Unit Cap").

The Unit Cap is subject to pro rata adjustments for any unit splits (including those effected pursuant to a distribution of our common units), subdivisions or combinations, in each case referred to as a “Unit Split,” with respect to our common units. The adjusted Unit Cap as the result of a Unit Split will be the number of our common units that is equal to the product obtained by multiplying (i) the Unit Cap in effect immediately prior to the Unit Split by (ii) a fraction, (a) the numerator of which is the number of our common units outstanding after giving effect to the Unit Split and (b) the denominator of which is the number of our common units outstanding immediately prior to the Unit Split.

In the case of a Change of Control pursuant to which our common units will be converted into cash, securities or other property or assets (including any combination thereof) (the “Alternative Conversion Consideration”), a holder of Series A Preferred Units electing to participate in the Series A Change of Control Conversion will receive upon conversion of the Series A Preferred Units elected by such holder the kind and amount of such consideration on a per unit basis which such holder would have owned or been entitled to receive upon the Change of Control had such holder held a number of common units equal to the Common Unit Conversion Consideration immediately prior to the effective time of the Change of Control; provided, that, if the holders of our common units have the opportunity to elect the form of consideration to be received in such Change of Control, the consideration that the holders of Series A Preferred Units electing to participate in the Series A Change of Control Conversion will receive will be the form and proportion of the aggregate consideration elected by the holders of our common units who participate in the determination (based on the weighted average of elections) and will be subject to any limitations to which all holders of our common units are subject, including, without limitation, pro rata reductions applicable to any portion of the consideration payable in the Change of Control. No fractional units will be issued upon the conversion of the Series A Preferred Units. Instead, we will pay the cash value of such fractional units.

However, if prior to the Change of Control Conversion Date, we provide (or, if applicable, a third party with our prior written consent provides) notice of our (or its) election to redeem Series A Preferred Units as described under “Redemption—Optional Redemption” or “Change of Control—Redemption upon a Change of Control”, holders of Series A Preferred Units will not have any right to convert the Series A Preferred Units that we have (or a third party with our prior written consent has) elected to redeem, and any Series A Preferred Units subsequently selected for redemption that have been tendered for conversion will be redeemed on the related redemption date instead of converted on the Change of Control Conversion Date.

Within 30 days following the occurrence of a Change of Control, we (or a third party with our prior written consent) will provide to holders of Series A Preferred Units a notice of occurrence of the Change of Control that describes the resulting Change of Control Conversion Right (as defined below) and states the following:

- the events constituting the Change of Control;
- the date of the Change of Control;
- the Change of Control Conversion Date;
- the last date on which the holders of Series A Preferred Units may exercise their Change of Control Conversion Right;
- the method and period for calculating the Common Unit Conversion Consideration;
- that if prior to the Change of Control Conversion Date, we provide (or, if applicable, a third party with our prior written consent provides) notice of our (or its) election to redeem Series A Preferred Units, holders of Series A Preferred Units will not have any right to convert the Series A Preferred Units that we have (or a third party with our prior written consent has) elected to redeem, and any Series A Preferred Units subsequently selected for redemption that have been tendered for conversion will be redeemed on the related redemption date instead of converted on the Change of Control Conversion Date;
- if applicable, the type and amount of Alternative Conversion Consideration entitled to be received per Series A Preferred Unit;
- the name and address of the Paying Agent; and

- the procedures that the holders of Series A Preferred Units must follow to exercise the Change of Control Conversion Right.

We (or a third party with our prior written consent) will issue a press release for publication through a news or press organization as is reasonably expected to broadly disseminate the relevant information to the public, or post notice on our website, in any event prior to the opening of business on the first Business Day (as defined below) following any date on which we provide (or a third party with our prior written consent provides) the notice described above to the holders of Series A Preferred Units.

Each holder of Series A Preferred Units electing to participate in the Series A Change of Control Conversion will be required prior to the close of business on the third Business Day preceding the Change of Control Conversion Date, to notify us in writing of the number of Series A Preferred Units held by such holder on the Change of Control Conversion Date that such holder elects to be converted in the Series A Change of Control Conversion and otherwise to comply with any applicable procedures of the Depositary for effecting the conversion. The failure of any holder of Series A Preferred Units to timely deliver a written notice in accordance with the immediately preceding sentence (or the delivery by a holder of Series A Preferred Units of a timely notice of exercise for only a portion, but not all, of the Series A Preferred Units held by such holder) will constitute an election by such holder to not participate in the Series A Change of Control Conversion (or to not participate in the Series A Change of Control Conversion as to the portion of the Series A Preferred Units held by such holder as to which a timely notice of exercise was not delivered).

Upon conversion, the rights of such participating holder as a holder of the Series A Preferred Units will cease with respect to such converted Series A Preferred Units, and such person will continue to be a partner and have the rights of a holder of common units under our Partnership Agreement. Each Series A Preferred Unit will, upon its Change of Control Conversion Date, be deemed to be transferred to, and cancelled by, us in exchange for the issuance of the common units upon such conversion.

We will comply with all applicable securities laws regulating the offer and delivery of any common units issued upon such conversion and, if our common units are then listed or quoted on a National Securities Exchange or other market, will list or cause to have quoted and keep listed and quoted such common units to the extent permitted or required by the rules of such exchange or market.

"Business Day" means Monday through Friday of each week, except that a legal holiday recognized as such by the government of the United States of America or the State of Texas will not be recognized as such.

"Change of Control Conversion Right" means the right of a holder of Series A Preferred Units to convert some or all of the Series A Preferred Units held by such holder on the Change of Control Conversion Date into a number of our common units per Series A Preferred Unit pursuant to the conversion provisions in our Partnership Agreement.

"Change of Control Conversion Date" means the date fixed by our general partner, in its sole discretion, as the date the Series A Preferred Units are to be converted into our common units. Such Change of Control Conversion Date will be a Business Day that is no fewer than 20 days nor more than 35 days after the date on which we provide the notice described above to holders of the Series A Preferred Units.

"National Securities Exchange" means an exchange registered with the Securities and Exchange Commission under Section 6(a) of the Securities Exchange Act of 1934.

Liquidation Rights

We will liquidate in accordance with capital accounts. A consolidation or merger of us with or into any other entity, individually or in a series of transactions, will not be deemed to be a liquidation, dissolution or winding up of our affairs. The holders of outstanding Series A Preferred Units will be specially allocated items of our gross income and gain in a manner designed to achieve, in the event of any liquidation, dissolution or winding up of our affairs, whether voluntary or involuntary, a liquidation preference of $25.00 per unit. If the amount of our gross income and gain available to be specially allocated to the Series A Preferred Units is not sufficient to cause the capital account of a Series A Preferred Unit to equal the liquidation preference of a Series A Preferred Unit, then the amount that a holder of Series A Preferred Units would receive upon liquidation may be less than the Series A Preferred Unit liquidation preference. Any accumulated and unpaid distributions on the Series A Preferred Units will be paid prior to any distributions in liquidation made in accordance with capital accounts. The rights of holders of Series A Preferred Units to receive the liquidation preference will be subject to the proportional rights of holders of Parity Securities.

Voting Rights

The Series A Preferred Units will have no voting, consent or approval rights except as set forth below or as otherwise provided by Delaware law.

Unless we have received the affirmative vote or consent of the holders of at least 66 ⅔% of the outstanding Series A Preferred Units, voting as a single class, no amendment to our Partnership Agreement may be adopted that would have a material adverse effect on the existing preferences, rights, powers or duties of the Series A Preferred Units.

In addition, unless we have received the affirmative vote or consent of the holders of at least 66 ⅔% of the outstanding Series A Preferred Units, voting as a class together with holders of any other Parity Securities upon which like voting rights have been conferred and are exercisable, we may not:

- create or issue any Parity Securities if the cumulative distributions payable on outstanding Series A Preferred Units are in arrears; or

- create or issue any Senior Securities.

On any matter described above in which the holders of the Series A Preferred Units are entitled to vote as a class (whether separately or together with the holders of any Parity Securities), such holders will be entitled to one vote per unit.

With respect to Series A Preferred Units that are held for a person's account by another person (such as a broker, dealer, bank, trust company or clearing corporation, or an agent of any of the foregoing), in whose name such Series A Preferred Units are registered, such other person will, in exercising the voting rights in respect of such Series A Preferred Units on any matter, and unless the arrangement between such persons provides otherwise, vote such Series A Preferred Units in favor of, and at the direction of, the person who is the beneficial owner, and we will be entitled to assume it is so acting without further inquiry.

Distributions

General

Holders of Series A Preferred Units are entitled to receive, when, as and if declared by the board of directors of our general partner out of legally available funds for such purpose, cumulative cash monthly distributions.

Distribution Rate

Distributions on the Series A Preferred Units are cumulative from the date of original issue and will be payable monthly in arrears on each Distribution Payment Date (as defined below), when, as and if declared by the board of directors of our general partner out of legally available funds for such purpose.

The initial distribution rate for the Series A Preferred Units from and including the date of original issue to, but not including, November 1, 2020 (the "Fixed Rate Period") is 9.00% per annum of the $25.00 liquidation preference per unit (equal to $2.25 per unit per annum). On and after November 1, 2020 (the "Floating Rate Period"), distributions on the Series A Preferred Units will accumulate at an annual floating rate equal to the one-month LIBOR plus a spread of 7.71%.

Unless otherwise determined by our general partner, distributions are deemed to have been paid out of our available cash with respect to the month then ended immediately preceding the month in which distribution payment was made.

LIBOR for each distribution period during the Floating Rate Period is determined by the Calculation Agent (as defined below), as of the applicable Determination Date (as defined below), in accordance with the following provisions:

- the offered quotation to leading banks in the London interbank market for one-month dollar deposits as defined by the British Bankers' Association (or its successor in such capacity, such as NYSE Euronext Rate Administration Ltd.) and calculated by the Calculation Agent and published, as such rate appears: (i) on the Reuters Monitor Money Rates Service Page LIBOR01 (as defined below) (or a successor page on such service) or (ii) if such rate is not available, on such other information system that provides such information, in each case as of 11:00 a.m., London time, on such Determination Date;

- if no such rate is so published, then the rate for such Determination Date shall be the arithmetic mean (rounded to five decimal places, with 0.000005 being rounded upwards) of the rates for one-month dollar deposits quoted to the Calculation Agent as of 11:00 a.m., London time, on such Determination Date, it being understood that at least two such quotes must have been so provided to the Calculation Agent; or

- if LIBOR cannot be determined on such Determination Date using the foregoing methods, then the LIBOR for the relevant distribution period shall be the LIBOR as determined using the foregoing methods for the first day before such Determination Date on which LIBOR can be so determined.

All percentages resulting from any of the above calculations will be rounded, if necessary, to the nearest one hundred-thousandth of a percentage point, with five one-millionths of a percentage point rounded upwards (e.g., 9.876545% (or .09876545) being rounded to 9.87655% (or .0987655)) and all dollar amounts used in or resulting from such calculations will be rounded to the nearest cent (with one-half cent being rounded upwards).

"Calculation Agent" means U.S. Bank National Association, or any other firm appointed by us as the "Calculation Agent" for the Series A Preferred Units. "Determination Date" means the second London Business Day (as defined below) immediately preceding the applicable distribution period.

"London Business Day" means any day on which dealings in deposits in U.S. dollars are transacted in the London interbank market.

"Reuters Monitor Money Rates Service Page LIBOR01" means the display designated on page "LIBOR01" on Reuters (or such other page as may replace the LIBOR01 page on that service or any successor service for the purpose of displaying London interbank offered rates for U.S. dollar deposits of major banks).

Distribution Payment Dates

The "Distribution Payment Dates" for the Series A Preferred Units are on the 15th day of each month. Such distributions are paid to the holders of record as of the close of business on the last business day of the month preceding the applicable Distribution Payment Date. Distributions are cumulative and accumulate at the applicable distribution rate in each distribution period from and including the initial issue date or the first day of the following month, as the case may be, to and including the last day of that month until such time as we pay the distribution, convert all of the outstanding Series A Preferred Units as described under "Change of Control — Change of Control Rights" or redeem all of the outstanding Series A Preferred Units as described under Redemption — Optional Redemption" and "Change of Control — Redemption upon a Change of Control," whether or not such distributions have been declared. Distributions accumulate on the amount of distributions in arrears at the applicable distribution rate. If any Distribution Payment Date during the Fixed Rate Period otherwise falls on a day that is not a Business Day, declared distributions are paid on the immediately succeeding Business Day without the accumulation of additional distributions. If any Distribution Payment Date during the Floating Rate Period otherwise falls on a day that is not a Business Day, declared distributions are paid on the immediately succeeding Business Day without the accumulation of additional distributions, unless that day falls in the next calendar month, in which case the Distribution Payment Date is the immediately preceding Business Day. Distributions on the Series A Preferred Units for any distribution period in the Fixed Rate Period are payable based on a 360-day year consisting of twelve 30-day months, with the result that the amount of the distribution for each distribution period (other than the initial such period) equals $0.1875 per unit. Distributions on the Series A Preferred Units for any distribution period in the Floating Rate Period are payable based on the actual number of days in a distribution period and a 360-day year.

Payment of Distributions

Not later than 5:00 p.m., New York City time, on each Distribution Payment Date, we pay monthly distributions, if any, on the Series A Preferred Units that have been declared by the board of directors of our general partner to the holders of such units as such holders' names appear on our unit transfer books maintained by the Transfer Agent on the applicable record date. The record date is as of the close of the national securities exchange on which the Series A Preferred Units are listed or admitted to trading on the last Business Day of each month immediately preceding the applicable Distribution Payment Date, except that in the case of payments of distributions in arrears, the record date with respect to a Distribution Payment Date is such date as may be designated by the board of directors of our general partner in accordance with our Partnership Agreement.

So long as the Series A Preferred Units are held of record by the nominee of the Depositary, declared distributions are paid to the Depositary in same-day funds on each Distribution Payment Date. The Depositary credits accounts of its participants in accordance with the Depositary's normal procedures. The participants are responsible for holding or disbursing such payments to beneficial owners of the Series A Preferred Units in accordance with the instructions of such beneficial owners.

No distribution may be declared or paid or set apart for payment on any Junior Securities (other than a distribution payable solely in Junior Securities) unless full cumulative distributions have been or contemporaneously are being paid or provided for on all outstanding Series A Preferred Units and any Parity Securities through the most recently completed respective distribution periods. Accumulated distributions in arrears for any past distribution period may be declared by the board of directors of our general partner and paid on any date fixed by the board of directors of our general partner, whether or not a Distribution Payment Date, to holders of the Series A Preferred Units on the record date for such payment, which may not be less than 10 days before such payment date. Subject to the next succeeding sentence, if all accumulated distributions in arrears on all outstanding Series A Preferred Units and any Parity Securities have not been declared and paid, or sufficient funds for the payment thereof have not been set apart, payment of accumulated distributions in arrears will be made in order of their respective distribution payment dates, commencing with the earliest. If less than all distributions payable with respect to all Series A Preferred Units and any Parity Securities are paid, any partial payment is made pro rata with respect to the Series A Preferred Units and any Parity Securities entitled to a distribution payment at such time in proportion to the aggregate amounts remaining due in respect of such Series A Preferred Units and Parity Securities at such time. Holders of the Series A Preferred Units are not entitled to any distribution, whether payable in cash, property or partnership securities, in excess of full cumulative distributions. Except insofar as interest or sum of money in lieu of interest is payable in respect of any distribution payment which may be in arrears on the Series A Preferred Units.

Redemption

Optional Redemption

At any time on or after November 1, 2020, we may redeem the Series A Preferred Units, in whole or in part, from any source of funds legally available for such purpose, by paying $25.00 per unit plus an amount equal to all accumulated and unpaid distributions thereon to the date of redemption, whether or not declared. Any such redemption by the Partnership will be subject to compliance with the provisions of our senior secured credit facility, the indentures governing our outstanding senior notes and any other agreements governing our future or existing outstanding indebtedness.

We (or a third party with our prior written consent) may also redeem the Series A Preferred Units under the terms set forth under "Change of Control — Redemption upon a Change of Control."

Redemption Procedures

We or, in the case of a redemption described under "Change of Control — Redemption upon a Change of Control," a third party with our prior written consent (such third party or us, as applicable, the "Redeeming Party") will give written notice of its election to redeem Series A Preferred Units as set forth above under "— Optional Redemption" or "Change of Control — Redemption upon a Change of Control" not less than 30 days and not more than 60 days before the scheduled date of redemption, to the holders of any units to be redeemed as such holders' names appear (as of 5:00 p.m. New York City time on the Business Day next preceding the day on which notice is given) on our unit transfer books maintained by the Transfer Agent at the address of such holders shown therein. Such notice will state: (i) the redemption date, (ii) the number of Series A Preferred Units to be redeemed and, if fewer than all outstanding Series A Preferred Units are to be redeemed, the number (and, in the case of Series A Preferred Units in certificated form, the identification) of units to be redeemed from such holder, (iii) the redemption price, (iv) the place where any Series A Preferred Units in certificated form are to be redeemed and will be presented and surrendered for payment of the redemption price therefor and (v) that distributions on the units to be redeemed will cease to accumulate from and after such redemption date.

The Redeeming Party may give such notice in advance of a Change of Control if a definitive agreement is in place for the Change of Control at the time of giving such notice. The date of redemption may be on the date of the Change of Control, and any such redemption may be made simultaneously with the Change of Control.

If fewer than all of the outstanding Series A Preferred Units are to be redeemed, the number of units to be redeemed will be determined by the Redeeming Party, and such units will be redeemed by such method of selection as the Depositary (or, in the case of any certificated units, our general partner) determines, either pro rata or by lot, with adjustments to avoid redemption of fractional units. So long as all Series A Preferred Units are held of record by the nominee of the Depositary, the Redeeming Party will give notice, or cause notice to be given, to the Depositary of the number of Series A Preferred Units to be redeemed, and the Depositary will determine the number of Series A Preferred Units to be redeemed from the account of each of its participants holding such units in its participant account. Thereafter, each participant will select the number of units to be redeemed from each beneficial owner for whom it acts (including the participant, to the extent it holds Series A Preferred Units for its own account). A participant may determine to redeem Series A Preferred Units from some beneficial owners (including the participant itself) without redeeming Series A Preferred Units from the accounts of other beneficial owners. The Series A Preferred Units not redeemed will remain outstanding and entitled to all the rights and preferences of Series A Preferred Units under our Partnership Agreement.

So long as the Series A Preferred Units are held of record by the nominee of the Depositary, the redemption price will be paid by the Paying Agent to the Depositary on the redemption date. The Depositary's normal procedures provide for it to distribute the amount of the redemption price in same-day funds to its participants who, in turn, are expected to distribute such funds to the persons for whom they are acting as agent.

If the Redeeming Party gives a notice of redemption, then the Redeeming Party will deposit with the Paying Agent funds sufficient to redeem the Series A Preferred Units as to which notice has been given no later than 10:00 a.m., New York City time, on the date fixed for redemption, and the Redeeming Party will give the Paying Agent irrevocable instructions and authority to pay the redemption price to the holder or holders thereof upon surrender or deemed surrender (which will occur automatically if the certificate representing such units is issued in the name of the Depositary or its nominee) of the certificates therefor. If notice of redemption has been given, then from and after the date fixed for redemption, unless the Redeeming Party defaults in providing funds sufficient for such redemption at the time and place specified for payment pursuant to the notice, all distributions on such units will cease to accumulate and all rights of holders of such Series A Preferred Units with respect to such Series A Preferred Units will cease, except the right to receive the redemption price, plus an amount equal to accumulated and unpaid distributions to the date fixed for redemption, whether or not declared, and such Series A Preferred Units may not thereafter be transferred on the books of the Transfer Agent or be deemed to be outstanding for any purpose whatsoever.

The Redeeming Party will be entitled to receive from the Paying Agent the interest income, if any, earned on such funds deposited with the Paying Agent (to the extent that such interest income is not required to pay the redemption price of the Series A Preferred Units to be redeemed), and the holders of any Series A Preferred Units so redeemed will have no claim to any such interest income. Any funds deposited with the Paying Agent by the Redeeming Party for any reason, including redemption of Series A Preferred Units, that remain unclaimed or unpaid after two years after the applicable redemption date or other payment date, will be, to the extent permitted by law, repaid to us upon the Redeeming Party's written request, after which repayment the holders of Series A Preferred Units entitled to such redemption or other payment will have recourse only to the Redeeming Party.

If only a portion of the Series A Preferred Units represented by a certificate has been called for redemption, upon surrender of the certificate to the Paying Agent (which will occur automatically if the certificate representing such units is registered in the name of the Depositary or its nominee), we will issue and the Paying Agent will deliver to the holder of such units a new certificate (or adjust the applicable book-entry account) representing the number of Series A Preferred Units represented by the surrendered certificate that have not been called for redemption.

Notwithstanding any notice of redemption, there will be no redemption of any Series A Preferred Units called for redemption until funds sufficient to pay the full redemption price of such units, plus all accumulated and unpaid distributions to the date of redemption, whether or not declared, have been deposited by the Redeeming Party with the Paying Agent.

We and our affiliates may from time to time purchase Series A Preferred Units, subject to compliance with all applicable securities and other laws. Neither we nor any of our affiliates has any obligation, or any present plan or intention, to purchase any Series A Preferred Units. Any Series A Preferred Units that are redeemed or otherwise acquired by us will be cancelled.

Notwithstanding the foregoing, unless full cumulative distributions have been or contemporaneously are being paid or provided for on all outstanding Series A Preferred Units and any Parity Securities through the most recently completed respective distribution periods, we may not repurchase, redeem or otherwise acquire, in whole or in part, any Series A Preferred Units or Parity Securities except pursuant to a purchase or exchange offer made on the same relative terms to all holders of Series A Preferred Units and any Parity Securities. Common units and any other Junior Securities may not be redeemed, repurchased or otherwise acquired unless full cumulative distributions have been or contemporaneously are being paid or provided for on all outstanding Series A Preferred Units and any Parity Securities through the most recently completed respective distribution periods.

Amendment of the Partnership Agreement

General

Amendments to our Partnership Agreement may be proposed only by or with the consent of our general partner. However, our general partner will have no duty or obligation to propose any amendment and may decline to do so free of any fiduciary duty or obligation whatsoever to us or the limited partners, including any duty to act in good faith or in the best interests of us or the limited partners. In order to adopt a proposed amendment, other than the amendments discussed below, our general partner is required to seek written approval of the holders of the number of units (as defined in the Partnership Agreement) required to approve the amendment or call a meeting of the limited partners to consider and vote upon the proposed amendment. Except as described below, an amendment must be approved by a unit majority.

Prohibited Amendments

No amendment may be made that would:

- enlarge the obligations of any limited partner without its consent, unless approved by at least a majority of the type or class of limited partner interests so affected; or

- enlarge the obligations of, restrict in any way any action by or rights of, or reduce in any way the amounts distributable, reimbursable or otherwise payable by us to our general partner or any of its affiliates without the consent of our general partner, which consent may be given or withheld at its option.

The provision of our Partnership Agreement preventing the amendments having the effects described in any of the clauses above can be amended upon the approval of the holders of at least 90% of the outstanding units voting together as a single class (including units owned by our general partner and its affiliates).

No Unitholder Approval

Our general partner may generally make amendments to our Partnership Agreement without the approval of any limited partner or assignee to reflect:

- a change in our name, the location of our principal place of our business, our registered agent or our registered office;

- the admission, substitution, withdrawal or removal of partners in accordance with our Partnership Agreement;
- a change that our general partner determines to be necessary or appropriate to qualify or continue our qualification as a limited partnership or a partnership in which the limited partners have limited liability under the laws of any state or to ensure that neither we nor our operating subsidiary nor any of its subsidiaries will be treated as an association taxable as a corporation or otherwise taxed as an entity for federal income tax purposes;
- a change in our fiscal year and related changes;
- an amendment that is necessary, in the opinion of our counsel, to prevent us or our general partner or the directors, officers, agents or trustees of our general partner from in any manner being subjected to the provisions of the Investment Company Act of 1940, the Investment Advisors Act of 1940, or “plan asset” regulations adopted under the Employee Retirement Income Security Act of 1974, or ERISA, whether or not substantially similar to plan asset regulations currently applied or proposed;
- an amendment that our general partner determines to be necessary or appropriate for the authorization of additional partnership securities or rights to acquire partnership securities;
- any amendment expressly permitted in our Partnership Agreement to be made by our general partner acting alone;
- an amendment effected, necessitated or contemplated by a merger agreement that has been approved under the terms of our Partnership Agreement;
- any amendment that our general partner determines to be necessary or appropriate for the formation by us of, or our investment in, any corporation, partnership or other entity, as otherwise permitted by our Partnership Agreement;
- conversions into, mergers with or conveyances to another limited liability entity that is newly formed and has no assets, liabilities or operations at the time of the conversion, merger or conveyance other than those it receives by way of the conversion, merger or conveyance; or
- any other amendments substantially similar to any of the matters described in the clauses above.

In addition, our general partner may make amendments to our Partnership Agreement without the approval of any limited partner if our general partner determines that those amendments:

- do not adversely affect the limited partners (or any particular class of limited partners) in any material respect;
- are necessary or appropriate to satisfy any requirements, conditions or guidelines contained in any opinion, directive, order, ruling or regulation of any federal or state agency or judicial authority or contained in any federal or state statute;
- are necessary or appropriate to facilitate the trading of limited partner interests or to comply with any rule, regulation, guideline or requirement of any securities exchange on which the limited partner interests are or will be listed for trading;
- are necessary or appropriate for any action taken by our general partner relating to splits or combinations of units under the provisions of our Partnership Agreement; or

- are required to effect the intent of the provisions of our Partnership Agreement or are otherwise contemplated by our Partnership Agreement.

Opinion of Counsel and Unitholder Approval.

For amendments of the type not requiring limited partner approval, our general partner will not be required to obtain an opinion of counsel that an amendment will not result in a loss of limited liability to the limited partners or result in our being treated as an association taxable as a corporation or otherwise taxable as an entity for federal income tax purposes in connection with any of the amendments. No amendments to our Partnership Agreement other than those described above under "— No Unitholder Approval" will become effective without the approval of holders of at least 90% of the outstanding units voting as a single class unless we first obtain an opinion of counsel to the effect that the amendment will not affect the limited liability under applicable law of any of our limited partners.

In addition to the above restrictions, any amendment that would have a material adverse effect on the rights or preferences of any type or class of partnership interests in us in relation to other classes of partnership interests in us will require the approval of at least a majority of the type or class of partnership interests so affected. Any amendment that reduces the voting percentage required to take any action is required to be approved by the affirmative vote of limited partners whose aggregate outstanding partnership interests constitute not less than the voting requirement sought to be reduced.

Merger, Consolidation, Conversion, Sale or Other Disposition of Assets

A merger, consolidation or conversion of us requires the prior consent of our general partner. However, our general partner will have no duty or obligation to consent to any merger, consolidation or conversion and may decline to do so free of any fiduciary duty or obligation whatsoever to us or the limited partners, including any duty to act in good faith or in the best interest of us or the limited partners.

In addition, our Partnership Agreement generally prohibits our general partner without the prior approval of the holders of a unit majority, from causing us to, among other things, sell, exchange or otherwise dispose of all or substantially all of our assets in a single transaction or a series of related transactions, including by way of merger, consolidation or other combination, or approving on our behalf the sale, exchange or other disposition of all or substantially all of the assets of our subsidiaries. Our general partner may, however, mortgage, pledge, hypothecate or grant a security interest in all or substantially all of our assets without that approval. Our general partner may also sell all or substantially all of our assets under a foreclosure or other realization upon those encumbrances without that approval. Finally, our general partner may consummate any merger without the prior approval of our unitholders if we are the surviving entity in the transaction, our general partner has received an opinion of counsel regarding limited liability and tax matters, the transaction would not result in a material amendment to our Partnership Agreement, each of our partnership securities will be an identical partnership security of us following the transaction, and the partnership securities to be issued do not exceed 20% of our outstanding partnership securities immediately prior to the transaction.

If the conditions specified in our Partnership Agreement are satisfied, our general partner may convert us or any of our subsidiaries into a new limited liability entity or merge us or any of our subsidiaries into, or convey all of our assets to, a newly formed entity if the sole purpose of that conversion, merger or conveyance is to effect a mere change in our legal form into another limited liability entity, our general partner has received an opinion of counsel regarding limited liability and tax matters, and the governing instruments of the new entity provide the limited partners and the general partner with the same rights and obligations as contained in our Partnership Agreement. The holders of the Series A Preferred Units are not entitled to dissenters' rights of appraisal under our Partnership Agreement or applicable Delaware law in the event of a conversion, merger or consolidation, a sale of substantially all of our assets or any other similar transaction or event.

Withdrawal or Removal of the General Partner

Our general partner may withdraw as general partner without first obtaining approval of any holder of the Series A Preferred Units by giving 90 days' written notice, and that withdrawal will not constitute a violation of our Partnership Agreement. Notwithstanding the information above, our general partner may withdraw without approval of the holders of the Series A Preferred Units upon 90 days' notice to the limited partners if at least 50% of the outstanding common units are held or controlled by one person and its affiliates other than the general partner and its affiliates. In addition, our Partnership Agreement permits our general partner in some instances to sell or otherwise transfer all of its general partner interest in us without the approval of the holders of the Series A Preferred Units.

Upon withdrawal of our general partner under any circumstances, other than as a result of a transfer by our general partner of all or a part of its general partner interest in us, the holders of a unit majority, voting as separate classes, may select a successor to that withdrawing general partner. If a successor is not elected, or is elected but an opinion of counsel regarding limited liability and tax matters cannot be obtained, we will be dissolved, wound up and liquidated, unless within a specified period after that withdrawal, the holders of a unit majority agree in writing to continue our business and to appoint a successor general partner.

Our general partner may not be removed unless that removal is approved by the vote of the holders of not less than 66 ⅔% of the outstanding units, voting together as a single class, including units held by our general partner and its affiliates, and we receive an opinion of counsel regarding limited liability and tax matters. The ownership of more than 33 ⅓% of the outstanding units by our general partner and its affiliates would give them the practical ability to prevent our general partner's removal.

Our Partnership Agreement also provides that, if our general partner is removed as our general partner in accordance with our Partnership Agreement and under circumstances where cause does not exist, our general partner will have the right to convert its general partner interest into common units or to receive cash in exchange for those interests based on the fair market value of those interests at that time.

In the event of removal of a general partner under circumstances where cause exists or withdrawal of a general partner where that withdrawal violates our Partnership Agreement, a successor general partner will have the option to purchase the general partner interest of the departing general partner for a cash payment equal to the fair market value of those interests. Under all other circumstances where a general partner withdraws or is removed by the limited partners, the departing general partner will have the option to require the successor general partner to purchase the general partner interest of the departing general partner for fair market value. In each case, this fair market value will be determined by agreement between the departing general partner and the successor general partner. If no agreement is reached, an independent investment banking firm or other independent expert selected by the departing general partner and the successor general partner will determine the fair market value. Or, if the departing general partner and the successor general partner cannot agree upon an expert, then an expert chosen by agreement of the experts selected by each of them will determine the fair market value.

If the option described above is not exercised by either the departing general partner or the successor general partner, the departing general partner interest will automatically convert into common units equal to the fair market value of those interests as determined by an investment banking firm or other independent expert selected in the manner described in the preceding paragraph.

In addition, we are required to reimburse the departing general partner for all amounts due the departing general partner, including, without limitation, all employee-related liabilities, including severance liabilities, incurred for the termination of any employees employed by the departing general partner or its affiliates for our benefit.

Change of Management Provisions

Our Partnership Agreement contains specific provisions that are intended to discourage a person or group from attempting to remove our general partner or otherwise change the management of our general partner. If any person or group other than our general partner and its affiliates acquires beneficial ownership of 20% or more of any class of partnership securities, that person or group loses voting rights on all of its partnership securities. This loss of voting rights does not apply to any person or group that acquires the partnership securities from our general partner or its affiliates and any transferees of that person or group approved by our general partner or to any person or group who acquires the partnership securities with the prior approval of the board of directors of our general partner.

Our Partnership Agreement also provides that if our general partner is removed as our general partner under circumstances where cause does not exist and units held by our general partner and its affiliates are not voted in favor of that removal our general partner will have the right to convert its general partner units into common units or to receive cash in exchange for those interests based on the fair market value of those interests at that time.

Limited Call Right

If at any time our general partner and its affiliates own more than 80% of the then-issued and outstanding limited partner interests of any class, our general partner will have the right, which it may assign in whole or in part to any of its affiliates or to us, to acquire all, but not less than all, of the limited partner interests of the class held by unaffiliated persons as of a record date to be selected by our general partner, on at least 10 but not more than 60 days' notice. The purchase price in the event of this purchase is the greater of:

- the highest price paid by either of our general partner or any of its affiliates for any limited partner interests of the class purchased within the 90 days preceding the date on which our general partner first mails notice of its election to purchase those limited partner interests; and
- the current market price for any limited partner interests of the class purchased as of the date three days before the notice is mailed.

As a result of our general partner's right to purchase outstanding limited partner interests, a holder of limited partner interests may have his limited partner interests purchased at a price that may be lower than market prices at various times prior to such purchase or lower than a unitholder may anticipate the market price to be in the future. The tax consequences to a unitholder of the exercise of this call right are the same as a sale by that unitholder of his common units in the market.

Non-Citizen Assignees; Redemption

If we are or become subject to federal, state or local laws or regulations that, in the reasonable determination of our general partner, create a substantial risk of cancellation or forfeiture of any property that we have an interest in because of the nationality, citizenship or other related status of any limited partner, we may redeem the units held by such limited partner at their current market price. In order to avoid any cancellation or forfeiture, our general partner may require each limited partner to furnish information about his nationality, citizenship or related status. If a limited partner fails to furnish information about his nationality, citizenship or other related status within 30 days after a request for the information or our general partner determines after receipt of the information that the limited partner is not an eligible citizen, the limited partner may be treated as a non-citizen assignee. A non-citizen assignee is entitled to an interest equivalent to that of a limited partner for the right to share in allocations and distributions from us, including liquidating distributions. A non-citizen assignee does not have the right to direct the voting of his units and may not receive distributions in-kind upon our liquidation.

Right to Inspect Our Books and Records

Our partnership agreement provides that a limited partner can, for a purpose reasonably related to his interest as a limited partner, upon reasonable written demand stating the purpose of such demand and at his own expense, have furnished to him:

- a current list of the name and last known address of each partner;
- a copy of our tax returns;
- information as to the amount of cash, and a description and statement of the agreed value of any other property or services, contributed or to be contributed by each partner and the date on which each partner became a partner;

- copies of our partnership agreement, our certificate of limited partnership, related amendments and powers of attorney under which they have been executed;
- information regarding the status of our business and financial condition; and
- any other information regarding our affairs as is just and reasonable.

Our general partner may, and intends to, keep confidential from the limited partners trade secrets or other information the disclosure of which our general partner believes in good faith is not in our best interests or that we are required by law or by agreements with third parties to keep confidential.

No Sinking Fund

The Series A Preferred Units will not have the benefit of any sinking fund.

No Fiduciary Duty

We and our officers and directors will not owe any fiduciary duties to holders of the Series A Preferred Units other than a contractual duty of good faith and fair dealing pursuant to our Partnership Agreement.

Exhibit 21.1

Targa Resources Partners LP Subsidiary List

Entity Name	Jurisdiction of Formation
Allied CNG Ventures LLC	Delaware
Carnero G&P LLC	Delaware
Cayenne Pipeline, LLC	Delaware
Cedar Bayou Fractionators, L.P.	Delaware
Centrahoma Processing LLC	Delaware
DEVCO Holdings LLC	Delaware
Downstream Energy Ventures Co., L.L.C.	Delaware
FCPP Pipeline, LLC	Delaware
Flag City Processing Partners, LLC	Delaware
Floridian Natural Gas Storage Company, LLC	Delaware
Grand Prix Development LLC	Delaware
Grand Prix Pipeline LLC	Delaware
Gulf Coast Express Pipeline LLC	Delaware
Gulf Coast Fractionators	Texas
Little Missouri 4 LLC	Delaware
Pecos Pipeline LLC	Delaware
Sajet Development LLC	Delaware
Sajet Properties LLC	Delaware
Sajet Resources LLC	Delaware
Salta Properties LLC	Delaware
Setting Sun Pipeline Corporation	Delaware
Slider WestOk Gathering, LLC	Delaware
T2 Eagle Ford Gathering Company LLC	Delaware
T2 Gas Utility LLC	Texas
T2 LaSalle Gas Utility LLC	Texas
T2 LaSalle Gathering Company LLC	Delaware
Targa Acquisition LLC	Delaware
Targa Badlands Holdings LLC	Delaware
Targa Badlands LLC	Delaware
Targa Canada Liquids Inc.	British Columbia
Targa Capital LLC	Delaware
Targa Chaney Dell LLC	Delaware
Targa Channelview LLC	Delaware
Targa Cogen LLC	Delaware
Targa Delaware LLC	Delaware
Targa Downstream LLC	Delaware
Targa Gas Marketing LLC	Delaware
Targa Gas Pipeline LLC	Delaware
Targa Gas Processing LLC	Delaware
Targa GCX Pipeline LLC	Delaware
Targa Holding LLC	Delaware
Targa Intrastate Pipeline LLC	Delaware
Targa Liquids Marketing and Trade LLC	Delaware
Targa Louisiana Intrastate LLC	Delaware
Targa Midkiff LLC	Delaware
Targa Midland Gas Pipeline LLC	Delaware
Targa Midland LLC	Delaware
Targa Midstream Services LLC	Delaware
Targa MLP Capital LLC	Delaware
Targa NGL Pipeline Company LLC	Delaware
Targa Pipeline Escrow LLC	Delaware
Targa Pipeline Finance Corporation	Delaware
Targa Pipeline Mid-Continent Holdings LLC	Delaware
Targa Pipeline Mid-Continent LLC	Delaware
Targa Pipeline Mid-Continent WestOk LLC	Delaware
Targa Pipeline Mid-Continent WestTex LLC	Delaware
Targa Pipeline Operating Partnership LP	Delaware
Targa Pipeline Partners GP LLC	Delaware
Targa Pipeline Partners LP	Delaware
Targa Receivables LLC	Delaware
Targa Resources Operating GP LLC	Delaware
Targa Resources Operating LLC	Delaware
Targa Resources Partners Finance Corporation	Delaware
Targa Resources Partners LP	Delaware
Targa Southern Delaware LLC	Delaware
Targa SouthOk NGL Pipeline LLC	Oklahoma
Targa SouthTex Midstream Company LP	Texas

Targa Train 6 LLC	Delaware
Targa Train 7 LLC	Delaware
Targa Train 8 LLC	Delaware
Targa Transport LLC	Delaware
Terracotta Ventures LLC	Delaware
Tesla Resources LLC	Delaware
Tesuque Pipeline, LLC	Delaware
TPL Arkoma Holdings LLC	Delaware
TPL Arkoma Inc.	Delaware
TPL Arkoma Midstream LLC	Delaware
TPL Barnett LLC	Delaware
TPL Gas Treating LLC	Delaware
TPL SouthTex Gas Utility Company LP	Texas
TPL SouthTex Midstream Holding Company LP	Texas
TPL SouthTex Midstream LLC	Delaware
TPL SouthTex Pipeline Company LLC	Texas
TPL SouthTex Processing Company LP	Texas
TPL SouthTex Transmission Company LP	Texas
Velma Gas Processing Company, LLC	Delaware
Velma Intrastate Gas Transmission Company, LLC	Delaware
Venice Energy Services Company, L.L.C.	Delaware
Versado Gas Processors, L.L.C.	Delaware

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 Annual Report on Form 10-K of Targa Resources Partners LP (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: February 20, 2020

By:	/s/ Joe Bob Perkins
Name:	Joe Bob Perkins
Title:	Chief Executive Officer of Targa Resources GP LLC, the general partner of Targa Resources Partners LP (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 Annual Report on Form 10-K of Targa Resources Partners LP (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: February 20, 2020

By:	/s/ Jennifer R. Kneale
Name:	Jennifer R. Kneale
Title:	Chief Financial Officer of Targa Resources GP LLC, the general partner of Targa Resources Partners LP (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 Annual Report on Form 10-K of Targa Resources Partners LP (the "Partnership") for the year ended December 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 GP LLC, the general partner of the Partnership, 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 the Partnership.

By:	/s/ Joe Bob Perkins
Name:	Joe Bob Perkins
Title:	Chief Executive Officer

of Targa Resources GP LLC, the general partner of Targa Resources Partners LP

Date: February 20, 2020

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 the Partnership and will be retained by the Partnership 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 Annual Report on Form 10-K of Targa Resources Partners LP (the “Partnership”) for the year ended December 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 GP LLC, the general partner of the Partnership, 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 the Partnership.

By: /s/ Jennifer R. Kneale
Name: Jennifer R. Kneale
Title: Chief Financial Officer
of Targa Resources GP LLC, the general partner of Targa Resources Partners LP

Date: February 20, 2020

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 the Partnership and will be retained by the Partnership and furnished to the Securities and Exchange Commission or its staff upon request.