Targa Resources Corp.
Form 10-K
February 16, 2018

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, 2017

OR

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

Commission File Number: 001-34991

TARGA RESOURCES CORP.

(Exact name of registrant as specified in its charter)

Delaware	20-3701075
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
811 Louisiana St, Suite 2100, Houston, Texas	77002
(Address of principal executive offices)	(Zip Code)

(713) 584-1000

(Registrant's telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
Common Stock	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 and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

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

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

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

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

The aggregate market value of the common stock held by non-affiliates of the registrant was approximately $9,571.8 million on June 30, 2017, based on $45.20 per share, the closing price of the common stock as reported on the New York Stock Exchange (NYSE) on such date.

As of February 12, 2018, there were 218,830,282 shares of the registrant's common stock, $0.001 par value, outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None

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CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

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

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

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

- the timing and extent of changes in natural gas, natural gas liquids, crude oil and other commodity prices, interest rates and demand for our services;
- the level and success of crude oil and natural gas drilling around our assets, our success in connecting natural gas supplies to our gathering and processing systems, oil supplies to our gathering systems and natural gas liquid supplies to our logistics and marketing facilities and our success in connecting our facilities to transportation services and markets;
- our ability to access the capital markets, which will depend on general market conditions and the credit ratings for the Partnership's and our debt obligations;
- the amount of collateral required to be posted from time to time in our transactions;
- our success in risk management activities, including the use of derivative instruments to hedge commodity price risks;
- the level of creditworthiness of counterparties to various transactions with us;
- changes in laws and regulations, particularly with regard to taxes, safety and protection of the environment;
- weather and other natural phenomena;
- industry changes, including the impact of consolidations and changes in competition;
- our ability to obtain necessary licenses, permits and other approvals;
- our ability to grow through acquisitions or internal growth projects and the successful integration and future performance of such assets;
- general economic, market and business conditions; and
- the risks described 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.

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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
GPM	Liquid volume equivalent expressed as gallons per 1000 cu. ft. of natural gas
LACT	Lease Automatic Custody Transfer
LIBOR	London Interbank Offered Rate
LPG	Liquefied petroleum gas
MBbl	Thousand barrels
MMBbl	Million barrels
MMBtu	Million British thermal units
MMcf	Million cubic feet
MMgal	Million U.S. gallons
NGL(s)	Natural gas liquid(s)
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
SCOOP	South Central Oklahoma Oil Province
STACK	Sooner Trend, Anadarko, Canadian and Kingfisher

Price Index Definitions

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

PART I

Item 1. Business.

Overview

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

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.

Organization Structure

On February 17, 2016, TRC completed its acquisition of all of the outstanding common units of Targa Resources Partners LP (NYSE: NGLS), pursuant to the Agreement and Plan of Merger (the “TRC/TRP Merger Agreement”, and such transaction, the “TRC/TRP Merger” or “Buy-in Transaction”). We issued 104,525,775 shares of common stock in exchange for all of the outstanding common units of the Partnership that we previously did not own. As a result of the completion of the TRC/TRP Merger, the TRP common units are no longer publicly traded. The Partnership’s 9.00% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the “Preferred Units”) that were issued in October 2015 remain outstanding as preferred limited partner interests in TRP and continue to trade on the New York Stock Exchange (“NYSE”) under the symbol “NGLS PRA.” TRC also maintains a 2% general partner interest in the Partnership.

On October 19, 2016, TRP executed the Third Amended and Restated Agreement of Limited Partnership (the “Third A&R Partnership Agreement”), effective as of December 1, 2016. In connection with the Third A&R Partnership Agreement, TRP issued to Targa Resources GP LLC (the “General Partner”) (i) 20,380,286 common units and 424,590 General Partner units in exchange for the cancellation of the incentive distribution rights (“IDRs”) and (ii) 11,267,485 common units and 234,739 General Partner units in exchange for cancellation of the Special GP Interest. 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.”

The diagram below shows our corporate structure as of February 12, 2018, which reflects the effect of the TRC/TRP Merger:

(1) Common shares outstanding as of February 12, 2018.

Our Operations

We are engaged in the business of:

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

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

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

Our Logistics and Marketing segment includes the activities and assets necessary to convert mixed NGLs into NGL products and also includes other assets and value-added services such as storing, fractionating, terminaling, transporting and marketing of NGLs and NGL products, including services to LPG exporters; storing and terminaling of refined petroleum products and crude oil and certain natural gas supply and marketing activities in support of our other businesses. The Logistics and Marketing segment includes Grand Prix, as well as our equity interest in GCX, which are both currently under construction. The associated assets, including these pipeline projects, are generally connected to and supplied in part by our Gathering and Processing segment and, except for the pipeline projects and smaller terminals, are located predominantly in Mont Belvieu and Galena Park, Texas, and in Lake Charles, Louisiana.

Organic Growth Projects and Acquisitions

Since 2010, the year of our initial public offering, we have expanded our midstream natural gas and NGL services footprint substantially. The expansion of our business has been fueled by a combination of major organic growth investments in our businesses and third-party acquisitions. 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") and our 2015 acquisition of Atlas Pipeline Partners L.P. ("APL," renamed by us as Targa Pipeline Partners LP or "TPL"). In these transactions, we acquired (1) natural gas gathering, processing and treating assets in West Texas, South Texas, North Texas, Oklahoma and North Dakota, and (2) crude oil gathering and terminal assets in North Dakota. In 2017, we acquired additional gas gathering and processing and crude gathering systems located in the Permian Basin (the "Permian Acquisition"). See further discussion of the Permian Acquisition in the "Recent Developments" section below.

We also continue to invest significant capital to expand through organic growth projects. We have invested approximately $5.3 billion in growth capital expenditures since 2007, including approximately $1.4 billion in 2017. These expansion investments were distributed across our businesses, with 42% related to Logistics and Marketing and 58% to Gathering and Processing. We expect to continue to invest in both large and small organic growth projects in 2018. We currently estimate that we will invest at least $1.6 billion in organic growth capital expenditures for announced projects in 2018.

The map below highlights our more significant assets:

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Recent Developments

Gathering and Processing Segment Expansion

Permian Acquisition

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

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

New Delaware's gas gathering and processing and crude gathering assets are located in Loving, Winkler, Pecos and Ward counties. The operations are backed by producer dedications of more than 145,000 acres under long-term, largely fee-based contracts, with an average weighted contract life of 14 years. The New Delaware assets include 70 MMcf/d of processing capacity. In addition, the Oahu Plant, a 60 MMcf/d plant in the Delaware Basin, which is expected to be completed in the first quarter of 2018, will be added to New Delaware’s footprint. Currently, there is 40 MBbl/d of crude gathering capacity on the New Delaware system.

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

New Delaware's gas gathering and processing assets were connected to our Sand Hills system in the first quarter of 2017, and New Midland's gas gathering and processing assets were connected to our existing WestTX system in the fourth quarter of 2017. We believe connecting the acquired assets to our legacy Permian footprint creates operational and capital synergies, and is expected to afford enhanced flexibility in serving producers.

Additional Permian System Processing Capacity

In November 2016, we announced plans to build the 200 MMcf/d Joyce Plant in the Midland Basin, which is expected to be completed in the first quarter of 2018. We expect total net growth capital expenditures for the Joyce Plant to be approximately $80 million.

In the first quarter of 2017, we restarted the idled 45 MMcf/d Benedum cryogenic processing plant. We also added 20 MMcf/d of capacity at our Midkiff Plant in the second quarter of 2017 and increased overall plant capacity of the Midkiff/Consolidator Plant complex in Reagan County, Texas from 210 MMcf/d to 230 MMcf/d.

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

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

On February 6, 2018, we announced plans to construct two new 250 MMcf/d cryogenic natural gas processing plants in the Midland Basin to support increasing production. The two plants are expected to begin operations in the first and third quarters of 2019, respectively.

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Eagle Ford Shale Natural Gas Gathering and Processing Joint Ventures

The Raptor Plant, a gas processing facility with an initial capacity of 200 MMcf/d, and 45 miles of associated gathering pipelines, both part of a 50/50 joint venture with Sanchez Midstream Partners, L.P. (“SNMP”), which is associated with Sanchez Energy Corporation (“Sanchez”), began operations in the second quarter of 2017. In February 2017, we announced that we were going to add compression to increase the processing capacity of the Raptor Plant to 260 MMcf/d, which was completed in the fourth quarter of 2017. The Raptor Plant accommodates growing production from Sanchez’s premier Eagle Ford Shale acreage position in Dimmit, La Salle and Webb Counties, Texas and from other third party producers. The plant and high pressure gathering pipelines are supported by long-term, firm, fee-based contracts and acreage dedications with Sanchez. We manage operations of the high pressure gathering lines as well as the plant. Prior to the Raptor Plant being placed in service, we benefited from Sanchez natural gas volumes that were processed at our Silver Oak facilities in Bee County, Texas.

Eagle Ford Shale Acquisition of Flag City Natural Gas Processing Plant

In May 2017, we acquired a 150 MMcf/d natural gas processing plant (the “Flag City Plant”) and associated assets from subsidiaries of Boardwalk Pipeline Partners, L.P. (“Boardwalk”) for $60.0 million, subject to customary closing adjustments. The gas processing activities under commercial contracts related to the Flag City Plant have been redirected to our Silver Oak facilities. The Flag City Plant has been shut down and disassembled and will be installed as part of our SouthOK operations. See further details below in “SouthOK Expansion.”

SouthOK Expansion

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

Badlands

During 2017, we invested approximately $125 million to expand our crude gathering and natural gas processing business in the Williston Basin, North Dakota. The expansion included the addition of pipelines, LACT units, compression and other infrastructure to support continued growth in producer activity.

In January 2018, we announced the formation of a 50/50 joint venture with Hess Midstream Partners LP to construct a new 200 MMcf/d natural gas processing plant (“LM4 Plant”) at Targa’s existing Little Missouri facility. The LM4 Plant is expected to have a total cost of approximately $150 million and is anticipated to be completed in the fourth quarter of 2018. Targa will manage construction of, and operate, the LM4 Plant.

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

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

Downstream Segment Expansion

Grand Prix NGL Pipeline

In May 2017, we announced plans to construct a new common carrier NGL pipeline. The NGL pipeline (“Grand Prix”) will transport volumes from the Permian Basin and North Texas to our fractionation and storage complex in the NGL market hub at Mont Belvieu, Texas. Grand Prix will be supported by our volumes and other third-party customer commitments, and is expected to be in service in the second quarter of 2019. The capacity of the pipeline from the Permian Basin will be approximately 300 MBbl/d, expandable to 550 MBbl/d.

In September 2017, we sold a 25% interest in our consolidated subsidiary, Grand Prix Pipeline LLC (the "Grand Prix Joint Venture") to funds managed by Blackstone Energy Partners (“Blackstone”). We are the operator and construction manager of Grand Prix. Our share of total growth capital expenditures for Grand Prix is expected to be approximately $728 million.

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

Gulf Coast Express Pipeline

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

Channelview Splitter

On December 27, 2015, we and Noble Americas Corp., an affiliate of Noble Group Ltd., entered into a long-term, fee-based agreement (“Splitter Agreement”) under which Targa Terminals will build and operate a 35,000 Bbl/d crude oil and condensate splitter at our Channelview Terminal on the Houston Ship Channel (“Channelview Splitter”). The Channelview Splitter will have the capability to split approximately 35,000 Bbl/d of crude oil and condensate into its various components, including naphtha, kerosene, gas oil, jet fuel, and liquefied petroleum gas and will provide segregated storage for the crude, condensate and components. In January 2018, Vitol US Holding Co. acquired Noble Americas Corp.

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

Fractionation Expansion

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

Development Joint Ventures

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

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

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

2017 Financing Activities

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

On February 23, 2017, we amended the Partnership's account receivable securitization facility (the "Securitization Facility") to increase the facility size to $350.0 million from $275.0 million. In December 2017, the Securitization Facility was amended to extend the maturity to December 7, 2018.

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

On May 9, 2017, we entered into an equity distribution agreement under the May 2016 Shelf (as defined below) (the "May 2017 EDA"), pursuant to which we may sell through our sales agents, at our option, up to an aggregated amount of $750.0 million of our common stock. For the year ended December 31, 2017, no shares of common stock have been issued under the May 2017 EDA.

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

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

On October 17, 2017, the Partnership issued $750.0 million aggregate principal amount of 5% senior notes due January 2028 (the “5% Senior Notes due 2028”). The Partnership used the net proceeds of $744.1 million after costs from this offering to redeem its 5% Senior Notes due 2018, reduce borrowings under its credit facilities and for general partnership purposes.

On October 30, 2017, the Partnership redeemed its outstanding 5% Senior Notes due 2018 at par value plus accrued interest through the redemption date.

During the year ended December 31, 2017, we issued 6,433,561 shares through an equity distribution agreement under the May 2016 Shelf (the “December 2016 EDA”) associated with our ATM program, resulting in net proceeds of $343.1 million.

Growth Drivers

We believe that our near-term growth will be driven by the level of producer activity in the basins where our gathering and processing infrastructure is located and by the level of demand for services provided by our Downstream Business. We believe our assets are not easily duplicated and are located in many attractive and active areas of exploration and production activity and are near key markets and logistics centers. Over the longer term, we expect our growth will continue to be driven by 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 also continue to be a focus 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 processing 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 footprint, and are benefiting from increasing activity as rigs have been added in the basin 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 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 278 MBbl/d of additional fractionation capacity with the additions of Cedar Bayou Fractionator (“CBF”) Trains 3, 4 and 5. We believe that the higher volumes of fractionated NGLs will also result in increased demand for other related fee-based services provided by our Downstream Business. Continued demand for fractionation capacity is expected to lead to other 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 results in an increasing supply of NGLs. As drilling in these areas continues, the supply of NGLs requiring transportation and fractionation to market hubs is expected to continue. 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 will transport volumes from the Permian Basin and our North Texas system to our fractionation and storage complex in the NGL market hub at Mont Belvieu, Texas, further enhancing the integration of our gathering and processing assets with our Downstream Business. Grand Prix positions us to offer an integrated midstream service across the NGL value chain to our customers by linking supply to key markets. Grand Prix is expected to be in service in the second quarter of 2019.

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 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 fractionation opportunities from active crude oil resource plays. We believe that our leadership position in the Downstream Business, which includes our fractionation and export services and will be complemented by Grand Prix, 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 our initial public offering in 2010, we have executed on approximately $5.1 billion of growth capital projects and approximately $7.2 billion in third-party acquisitions. We expect that organic growth and third-party acquisitions will continue to be a focus of our strategy.

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 primarily by commodity 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. Once in service, Grand Prix will connect 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 crude, gather, process and treat wellhead gas to meet pipeline standards, and extract NGLs for sale into petrochemical, industrial, commercial and export markets. We believe that our ability to provide 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 GCX further enhance our position to offer an integrated midstream service across the natural gas and NGL value chain by linking supply to key markets. Additionally, we believe the barriers to enter the midstream sector on a scale similar to ours are reasonably high due to the high cost of replicating or acquiring assets in key strategic positions and the difficulty of developing the expertise necessary to operate them.

High quality and efficient assets

Our gathering and processing systems and logistics 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), measurements (essentially all electronic and electronically linked to a central data-base) and operations and maintenance 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 $94.8 million per year over the last three years. We believe that our assets are well-maintained and anticipate that a similar level of maintenance capital expenditures will be sufficient for us to continue to operate our existing 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 Marketing 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 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.

Financial flexibility

We have historically managed our leverage ratio, maintained sufficient liquidity and have funded our growth investments with a mix of equity and debt over time. Disciplined management of leverage, liquidity 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 includes a number of individuals who formed us in 2004, and several others who managed many of our businesses prior to acquisition by Targa. They possess a breadth and depth of experience working in the midstream energy business. Other officers and key operational, commercial and financial 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 has a contract mix that is primarily percent-of-proceeds, but also has increasing components of fee-based margin driven by fees added to percent-of-proceeds contracts for natural gas treating and compression, by new/amended contracts with a combination of percent-of-proceeds and fee-based components and by essentially fully fee-based crude oil gathering and gas gathering and processing in certain areas where fee-based contracts are prevalent such as the Williston Basin, South Oklahoma, South Texas and parts of the Permian Basin. Contracts in our Coastal Gathering and Processing segment are primarily hybrid (percent-of-liquids with a fee floor) or percent-of-liquids contracts. 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 and future commodity purchases and sales through 2020 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 domestic 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 Marketing (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 small 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 either the gatherers and processors or third parties. 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; the Eagle Ford Shale in South Texas; the Barnett Shale in North Texas; the Anadarko, Ardmore, and Arkoma Basins in Oklahoma (including the SCOOP and STACK) and South Central Kansas; the Williston Basin in North Dakota and in the onshore and near offshore regions of the Louisiana Gulf Coast and the Gulf of Mexico.

The natural gas processed in this segment is supplied through our gathering systems which, in aggregate, consist of approximately 27,000 miles of natural gas pipelines and include 37 owned and operated processing plants. During 2017, we processed an average of 3,473.6 MMcf/d of natural gas and produced an average of 333.2 MBbl/d of NGLs. In addition to our natural gas gathering and processing, our Badlands operations include a crude oil gathering system and four terminals with crude oil operational storage capacity of 125 MBbl, and our Permian operations include a crude oil gathering system and two terminals with crude oil operational storage capacity of 20 MBbl. During 2017, we gathered an average of 143.4 MBbl/d of crude oil.

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 operations consist of the San Angelo Operating Unit (“SAOU”) and WestTX:

SAOU

SAOU includes approximately 1,700 miles of pipelines in the Permian Basin that gather natural gas for delivery to the Mertzon, Sterling, Tarzan and High Plains processing plants. SAOU’s processing facilities are refrigerated cryogenic processing plants with an aggregate processing capacity of approximately 354 MMcf/d. These plants have residue gas connections to pipelines owned by affiliates of Atmos Energy Corporation (“Atmos”), Enterprise Products Partners L.P. (“Enterprise”), Kinder Morgan, Inc. (“Kinder Morgan”), Northern Natural Gas Company (“Northern”) and ONEOK, Inc. (“ONEOK”). SAOU has gathering lines that extend across nine counties.

WestTX

The WestTX gathering system has approximately 4,500 miles of natural gas gathering pipelines located across nine counties within the Permian Basin in West Texas. We have an approximate 72.8% ownership in the WestTX system. Pioneer, the largest active driller in the Spraberry and Wolfberry Trends and a major producer in the Permian Basin, owns the remaining interest in the WestTX system.

The WestTX system includes six separate plants: the Consolidator, Driver, Midkiff, Benedum, Edward and Buffalo processing facilities. The WestTX processing operations currently have an aggregate processing nameplate capacity of 875 MMcf/d. Two additional plants in the Permian Basin are currently under construction: 1) the 200 MMcf/d Joyce Plant, which is expected to be completed in the first quarter of 2018, and 2) the 200 MMcf/d Johnson Plant, which is expected to begin operations in the third quarter of 2018. In addition, two recently announced 250 MMcf/d plants are expected to begin operations in the first and third quarters of 2019, respectively.

The WestTX system has access to natural gas takeaway pipelines owned by affiliates of Atmos; Kinder Morgan; ONEOK; Enterprise; and Northern.

Permian Delaware

The Permian Delaware operations consist of Sand Hills and Versado:

Sand Hills

The Sand Hills operations consist of the Sand Hills and Loving gas processing plants and related gathering systems in West Texas. These systems consist of approximately 1,900 miles of natural gas gathering pipelines. These gathering systems are primarily low-pressure gathering systems with significant compression assets. The Sand Hills and Loving refrigerated cryogenic processing plants have aggregate processing capacity of 235 MMcf/d. These plants have residue gas connections to pipelines owned by affiliates of Enterprise, Kinder Morgan and ONEOK. Two additional plants in the Delaware Basin are currently under construction: 1) the 60 MMcf/d Oahu Plant, which is expected to be completed in the first quarter of 2018, and 2) the 250 MMcf/d Wildcat Plant, which is expected to begin operations in the second quarter of 2018.

Versado

Versado consists of the Saunders, Eunice and Monument gas processing plants and related gathering systems in Southeastern New Mexico and in West Texas. Versado includes approximately 3,600 miles of natural gas gathering pipelines. The Saunders, Eunice and Monument refrigerated cryogenic processing plants have aggregate processing capacity of 255 MMcf/d. These plants have residue gas connections to pipelines owned by affiliates of Kinder Morgan and MidAmerican Energy Company.

SouthTX

The SouthTX system processes natural gas through the Silver Oak I, Silver Oak II and Raptor gas processing plants. The Silver Oak I and II facilities are each 200 MMcf/d cryogenic plants located in Bee County, Texas. The Raptor facility includes a 260 MMcf/d cryogenic plant located in La Salle County, Texas, and approximately 45 miles of high pressure gathering pipelines. As of December 31, 2017, the Raptor gas processing plant and gas gathering facilities are complete and operational. The gathering facilities connect SNMP's Catarina gathering system to the Raptor plant. We operate the Carnero gas gathering and processing facilities.

The SouthTX gathering system includes approximately 800 miles of gathering pipelines located in the Eagle Ford Shale in southern Texas. Included in the total SouthTX pipeline mileage is our 75% interest in T2 LaSalle Gathering Company L.L.C. ("T2 LaSalle"), which has approximately 60 miles of gathering pipelines, and our 50% interest in T2 Eagle Ford Gathering Company L.L.C. ("T2 Eagle Ford"), which has approximately 120 miles of gathering pipelines. T2 LaSalle and T2 Eagle Ford are operated by a subsidiary of Southcross Holdings, L.P. ("Southcross"), which owns the remaining interests.

The SouthTX assets also include a 50% interest in T2 EF Cogeneration Holdings L.L.C. ("T2 Cogen", together with T2 LaSalle and T2 Eagle Ford, the "T2 Joint Ventures"), which owns a cogeneration facility. T2 Cogen is operated by Southcross, which owns the remaining interest in T2 Cogen.

The SouthTX system has access to natural gas takeaway pipelines owned by affiliates of Enterprise; Kinder Morgan; Williams Partners L.P.; CPS Energy; and Energy Transfer Partners, L.P. ("Energy Transfer").

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 4,600 miles of pipelines gathering wellhead natural gas. These plants have residue gas connections to pipelines owned by affiliates of Atmos, Energy Transfer, and Enterprise.

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. Natural gas gathered from the northern and eastern portions of the Shackelford gathering system is typically transported to the Chico plant for processing. The Shackelford plant has processing capacity of 13 MMcf/d.

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 1,500 miles of active pipelines.

The SouthOK system includes five separate operational processing plants: Velma, Velma V-60, Coalgate, Stonewall and Tupelo. The SouthOK processing operations currently have a total nameplate capacity of 560 MMcf/d. The 150 MMcf/d Hickory Hills Plant is currently under construction and expected to begin operations in the second half of 2018. The Coalgate, Stonewall, and Hickory Hills facilities are owned by Centrahoma. The SouthOK system has access to natural gas takeaway pipelines owned by affiliates of Enable Midstream Partners, L.P. (“Enable”); MPLX, LP; Kinder Morgan; ONEOK; and Southern Star Central Gas Pipeline, Inc. (“Southern Star”).

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 6,500 miles of natural gas gathering pipelines.

The WestOK system processes natural gas through 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, with total nameplate capacity of 458 MMcf/d. The WestOK system has access to natural gas takeaway pipelines owned by affiliates of Enable; Energy Transfer; and Southern Star.

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. They consist of approximately 4,445 MMcf/d of natural gas processing capacity, 11 MBbl/d of integrated fractionation capacity, 980 miles of onshore gathering system pipelines, and 200 miles of offshore gathering system pipelines. The processing plants are comprised of five wholly-owned and operated plants (including one idled), one partially owned and operated plant, and three partially owned plants which are not operated by us. 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 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 460 miles of crude oil gathering pipelines, 40 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 includes approximately 200 miles of natural gas gathering pipelines and the Little Missouri natural gas processing plant with a current gross processing capacity of approximately 90 MMcf/d. Additionally, the 200 MMcf/d LM4 Plant, in which we own a 50% interest and will operate, is expected to be completed in the fourth quarter of 2018.

The following table lists the Gathering and Processing segment's processing plants and related volumes for the year ended December 31, 2017:

Facility	Process Type (5)	Operated/ Non-Operated	% Owned	Location	Gross Processing Capacity (MMcf/d) (1)	Gross Plant Natural Gas Inlet Throughput Volume (MMcf/d) (2) (3) (4)	Gross NGL Production (MBbl/d) (2) (3) (4)
Permian Midland							
SAOU							
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	354.0	311.9	38.2
WestTX (6)							
Consolidator	Cryo	Operated	72.8	Reagan County, TX	150.0		
Midkiff	Cryo	Operated	72.8	Reagan County, TX	80.0		
Driver	Cryo	Operated	72.8	Midland County, TX	200.0		
Benedum	Cryo	Operated	72.8	Upton County, TX	45.0		
Edward	Cryo	Operated	72.8	Upton County, TX	200.0		
Buffalo	Cryo	Operated	72.8	Martin County, TX	200.0		
				Area Total	875.0	581.6	80.1
Permian Delaware							
Sand Hills							
Sand Hills	Cryo	Operated	100.0	Crane County, TX	165.0		
Loving	Cryo	Operated	100.0	Loving County, TX	70.0		
				Area Total	235.0	178.0	19.3
Versado (7)							
Saunders	Cryo	Operated	100.0	Lea County, NM	60.0		
Eunice	Cryo	Operated	100.0	Lea County, NM	110.0		
Monument	Cryo	Operated	100.0	Lea County, NM	85.0		
				Area Total	255.0	203.8	23.8
SouthTX							
Silver Oak I	Cryo	Operated	100.0	Bee County, TX	200.0		
Silver Oak II	Cryo	Operated	100.0	Bee County, TX	200.0		
Raptor	Cryo	Operated	50.0	La Salle County, TX	260.0		
				Area Total	660.0	273.2	30.4
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	268.1	30.2
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	100.0	Coal County, OK	120.0		

Velma	Cryo	Operated	100.0	Stephens County, OK	100.0		
Velma V-60	Cryo	Operated	100.0	Stephens County, OK	60.0		
				Area Total	560.0	494.0	42.8
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 (11)	Cryo	Operated	100.0	Woodward County, OK	28.0		
				Area Total	458.0	377.7	21.9
Coastal (12)							
Gillis (13)	Cryo	Operated	100.0	Calcasieu Parish, LA	180.0		
Acadia (14)	Cryo	Operated	100.0	Acadia Parish, LA	80.0		
Big Lake (15)	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 (16)	Cryo	Operated	100.0	Cameron Parish, LA	265.0		
Terrebone	RA	Non-operated	1.5	Terrebonne Parish, LA	950.0		
Toca	Cryo/RA	Non-operated	12.6	St. Bernard Parish, LA	1,150.0		
Sea Robin	Cryo	Non-operated	0.8	Vermillion Parish, LA	700.0		
				Area Total	4,445.0	728.8	38.6
Badlands							
Little Missouri (17)	Cryo/RA	Operated	100.0	McKenzie County, ND	90.0	56.5	7.9
				Segment System Total	8,410.0	3,473.6	333.2

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(1) 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.
(2) 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.
(3) Plant natural gas inlet and NGL production volumes represent 100% of ownership interests for our consolidated VESCO joint venture, Silver Oak II, Coalgate and Stonewall 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.
(4) Per day Gross Plant Natural Gas Inlet and NGL Production statistics for plants listed above are based on the number of days operational during 2017.
(5) Cryo – Cryogenic Processing; RA – Refrigerated Absorption Processing.
(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) The Chaney Dell plant was idled in December 2015 due to lower volumes in the WestOK system.
(11) The Chester plant was idled in May 2017 due to lower volumes in the WestOK system.
(12) Coastal also includes two offshore gathering systems which have a combined length of approximately 200 miles.
(13) The Gillis plant has fractionation capacity of approximately 11 MBbl/d.
(14) The Acadia plant is available and operates on the LOU system subject to market conditions.
(15) The Big Lake plant is available and operates subject to market conditions.
(16) The Lowry facility was idled in June 2015, but is available subject to market conditions.
(17) Little Missouri Trains I and II are Straight Refrigeration plants and Little Missouri Train III is a Cryo plant.

Logistics and Marketing Segment

Our Logistics and Marketing segment is also referred to as our Downstream Business. Our Downstream Business includes the activities and assets necessary to convert mixed NGLs into NGL products and also includes other assets and value-added services described below. The Logistics and Marketing segment includes Grand Prix, as well as our equity interest in GCX, which are both currently under construction. The associated assets, including these pipeline projects, are generally connected to and supplied in part by our Gathering and Processing segment and, except for the pipeline projects and smaller terminals, are located predominantly in Mont Belvieu and Galena Park, Texas, and in Lake Charles, Louisiana.

The Logistics and Marketing 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, Nevada, California, Florida, Alabama, Mississippi, Tennessee, Kentucky, New Jersey, Washington and Maryland. 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, and by Grand Prix once it is completed.

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

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.

Our NGL fractionation business is under 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, one at Mont Belvieu, Texas and the other at Lake Charles, Louisiana. We have an equity investment in the third fractionator, Gulf Coast Fractionators LP ("GCF"), also located at Mont Belvieu. In addition to the three stand-alone facilities in the Logistics Assets segment, we own fractionation assets at Chico and LOU in our Gathering and Processing segment.

In June 2016, we commissioned an additional fractionator, CBF Train 5, in Mont Belvieu, Texas. This expansion added 100 MBbl/d of fractionation capacity and is fully integrated with our existing Gulf Coast NGL storage, terminaling and delivery infrastructure, which includes an extensive network of connections to key petrochemical and industrial customers as well as our LPG export terminal at Galena Park on the Houston Ship Channel. In addition, we recently announced another 100 MBbl/d fractionator, which will be connected to most of our other Mont Belvieu and Galena Park facilities. The additional fractionator is expected to begin operations in the first quarter of 2019.

We also have a natural gasoline hydrotreater at Mont Belvieu, Texas that removes sulfur from natural gasoline, allowing customers to meet new, more stringent environmental 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 or provisions for deficiency payments.

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

Facility	% Owned	Gross Capacity (MBbl/d) (1)	Gross Throughput 2017 (MBbl/d)
Operated Facilities:			
Lake Charles Fractionator (Lake Charles, LA) (2)	100.0	55.0	3.6
Cedar Bayou Fractionator (Mont Belvieu, TX) (3)	88.0	493.0	348.9
Targa LSNG Hydrotreater (Mont Belvieu, TX)	100.0	35.0	34.6
LSNG treating volumes			26.6
Benzene treating volumes			21.6
Non-operated Facilities:			
Gulf Coast Fractionator (Mont Belvieu, TX)	38.8	125.0	100.9

(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 was idled during 2016 as raw volumes were directed to Cedar Bayou Fractionator. Starting in 2017, Lake Charles Fractionator runs in a mode of ethane/propane splitting for a local petrochemical customer and is still configured to handle raw product.
(3)

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 once it is operational. 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 Marketing segment, we own or operate a total of 39 storage wells at our facilities with a gross storage capacity of approximately 69 MMBbl, 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 project includes our facilities at both Mont Belvieu and the Galena Park Marine Terminal near Houston, Texas. The facilities have export capacity of approximately 7 MMBbl per month of propane and/or butane with the capability to export international grade low ethane propane. We have the capability to load VLGC vessels alongside small and medium sized export vessels. We continue to experience demand growth for US-based NGLs (both propane and butane) for export into international markets.

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

Facility	% Owned	Location	Description	Throughput for 2017 (Million gallons)	Number of Permitted Wells	Gross Storage Capacity (MMBbl)
Galena Park Marine Terminal (1)	100	Harris County, TX	NGL import/export terminal	3,832.7	N/A	0.8
Mont Belvieu Terminal & Storage	100	Chambers County, TX	Transport and storage terminal	16,530.4	21 (2)	47.6
Hackberry Terminal & Storage	100	Cameron Parish, LA	Storage terminal	590.4	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 also include volumes that have also been handled at the Mont Belvieu Terminal.
(2) Excludes six non-owned wells we operate on behalf of Chevron Phillips Chemical Company LLC ("CPC"). An additional well has been drilled and is being prepared for operations. Two additional wells are permitted.
(3) Five of 12 owned wells leased to Citgo Petroleum Corporation under long-term leases.

Our fractionation, storage and terminaling business includes approximately 900 miles of company-owned pipelines to transport mixed NGLs and specification products.

Petroleum Logistics

Our Petroleum Logistics business owns and operates storage and terminaling facilities in Texas, Maryland and Washington. These facilities not only serve the refined petroleum products and crude oil markets, but also include LPGs and biofuels. The following table details the Logistics and Marketing segment's petroleum logistics facilities:

Throughput for 2017	Gross Storage

Facility	% Owned	Location	Description	(Million gallons)	Capacity (MMBbl)
Channelview Terminal	100	Harris County, TX	Transport and storage terminal	146.5	0.6
Baltimore Terminal	100	Baltimore County, MD	Transport and storage terminal	53.3	0.5
Sound Terminal	100	Pierce County, WA	Transport and storage terminal	661.6	1.4

In addition, the Channelview Splitter, which is expected to be completed in the second quarter of 2018, will be part of our Petroleum Logistics business once in service.

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 Marketing segment, including exports. During the year ended December 31, 2017, our distribution and marketing services business sold an average of 490.0 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 Marketing 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 marketing 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 via 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 Marketing 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, 2017, include approximately 640 railcars that we lease and manage, approximately 130 leased and managed transport tractors and 18 company-owned pressurized NGL barges.

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

Facility	% Owned	Location	Description	Throughput for 2017 (Million gallons) (1)	Usable Storage Capacity (Million gallons)
Calvert City Terminal	100	Marshall County, KY	Propane terminal	9.2	0.1

Greenville Terminal	100	Washington County, MS	Marine propane terminal	16.0	1.5
Port Everglades Terminal	100	Broward County, FL	Marine propane terminal	17.9	1.6
Tyler Terminal	100	Smith County, TX	Propane terminal	7.6	0.2
Abilene Transport (2)	100	Taylor County, TX	Raw NGL transport terminal	20.0	0.1
Bridgeport Transport (2)	100	Jack County, TX	Raw NGL transport terminal	60.3	0.1
Gladewater Transport (2)	100	Gregg County, TX	Raw NGL transport terminal	9.3	0.3
Chattanooga Terminal	100	Hamilton County, TN	Propane terminal	13.3	0.9
Sparta Terminal	100	Sparta County, NJ	Propane terminal	13.8	0.2
Hattiesburg Terminal (3)	50	Forrest County, MS	Propane terminal	422.8	179.8
Winona Terminal	100	Flagstaff County, AZ	Propane terminal	12.1	0.3
Sound Terminal	100	Pierce County, WA	Propane terminal	6.4	0.2
Jacksonville Transload (4)	100	Duval County, FL	Butane transload	1.8	-
Fort Lauderdale Transload (4)	100	Broward County, FL	Butane transload	0.9	-
Eagle Lake Transload (4)	100	Polk County, FL	Butane/propane transload	4.4	-
Baltimore Transload (4) (5)	100	Baltimore County, MD	Propane transload	0.9	-

(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.
(5) Operational in the third quarter of 2017 and located at our Baltimore Petroleum Logistics facility.

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, crude oil and petroleum logistics 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 and 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. We maintain, on behalf of ourselves and our subsidiaries, including the Partnership, 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, 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 Enterprise, Kinder Morgan, WTG Gas Processing, L.P. (“WTG”), DCP, Devon Energy Corporation (“Devon”), Enbridge Inc., Enlink Midstream Partners LP, Energy Transfer, ONEOK, J-W Operating Company, Louisiana Intrastate Gas Company L.L.C., Enable, Medallion Midstream, LLC and several other interstate pipeline companies. Our competitors for crude oil gathering services in North Dakota include Crestwood Equity Partners LP, Kinder Morgan, Tesoro Corporation, Caliber Midstream Partners, L.P., Bridger Pipeline LLC, Paradigm Energy Partners, LLC and Summit Midstream Partners, LLC. Our competitors may have greater financial resources than we possess.

We also compete for NGL supplies for our NGL pipeline currently under construction. 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 Energy Transfer, Enterprise, ONEOK and DCP.

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, ONEOK and LoneStar NGL LLC. 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, Phillips 66 and LoneStar NGL LLC.

We also compete for NGL products to market through our Logistics and Marketing 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 Enterprise, Energy Transfer, DCP, ONEOK and BP p.l.c.

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.

Regulation of Interstate Natural Gas Pipelines

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 limited jurisdiction certificate of public convenience and necessity under the Natural Gas Act of 1938 (“NGA”) for the Driver Residue Pipeline. In the certificate order, among other things, FERC waived requirements pertaining to the filing of an initial rate for service, the filing of a tariff and compliance with specified accounting and reporting requirements. 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.

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 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 “—Other Federal Laws and Regulations Affecting Our Industry—FERC Market Transparency Rules.”

Intrastate Pipeline Regulation

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 “—Other Federal Laws and Regulations Affecting Our Industry—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 its 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.

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 Natural Gas Act. 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, and FERC has accepted the rates, which TPL SouthTex Transmission's predecessor filed, as being in accordance with the "fair and equitable" standard. On November 6, 2017, TPL SouthTex Transmission filed a petition for approval of its existing rates applicable to NGPA Section 311 service. We anticipate that the GCX Project, which is expected to be completed in 2019 and will transport natural gas from the Permian Basin to markets on the Texas Gulf Coast, will be subject to regulation by the RRC and under Section 311 of the NGPA.

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 operates our Tarzan plant residue gas pipeline, which provides NGPA Section 311 service and falls outside of the "stub" line exemption. We are currently in the process of filing all required registrations and rate documentation with the Texas RRC.

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.

Our intrastate NGL pipelines in Texas transport mixed and purity NGL streams between Targa's Mont Belvieu and Galena Park, Texas facilities. Additionally, we expect to begin operating portions of the Grand Prix pipeline in 2018, which would transport mixed NGLs from the Permian Basin to intermediate points in Texas and, beginning in 2019, 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 Texas Railroad Commission. They are also subject to United States 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 fractionators in Lake Charles, Louisiana, where the mixed NGLs streams are fractionated into various products. We deliver such refined petroleum products (ethane, propane, butanes and natural gasoline) out of our fractionator to and from Targa-owned storage, to other third-party facilities and to various third-party 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. Certain of our Louisiana intrastate NGL pipelines are subject to the Louisiana Public Service Commission 2015 General Order (the "LPSC Order") Docket No. R-33390. We are currently in the process of registering such lines in accordance with Section 1 of the LPSC Order.

Our intrastate 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.

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 "—Other Federal Laws and Regulations Affecting Our Industry—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 "—Other Federal Laws and Regulations Affecting Our Industry—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 "—Other Federal Laws and Regulations Affecting Our Industry—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.

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 marketing, production, pricing, community right-to-know, protection of the environment, safety 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."

Interstate Common Carrier Liquids Pipeline Regulation

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 a regulated twelve-inch diameter pipeline that runs between Lake Charles, Louisiana, and Mont Belvieu, Texas. This pipeline can move mixed NGLs and purity NGL products. Targa NGL also owns an eight-inch diameter pipeline and a twenty-inch diameter pipeline, each of which run between Mont Belvieu, Texas, and Galena Park, Texas. The eight-inch and the twenty-inch pipelines are also regulated and are 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. In 2018, Targa NGL will complete another pipeline for exports at Targa's Galena Park dock.

Additionally, we expect to begin operating portions of the Grand Prix pipeline in 2018, which would transport mixed NGLs from the Permian Basin, including points in New Mexico, to intermediate points in Texas, and beginning in 2019, 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. Several of these pipelines would qualify for a waiver of filing of the FERC tariffs.

Targa NGL also owns a twelve-inch diameter pipeline that runs between Mont Belvieu, Texas, and Galena Park, Texas, that transports NGLs and that has qualified for a waiver of applicable FERC regulatory requirements under the ICA based on current circumstances. The crude oil pipeline system that is part of the Badlands assets also qualifies for such a waiver. Although we do not presently make any interstate movements on our Texas crude oil pipeline system, in 2018 Targa Crude Pipeline LLC may construct a new pipeline connecting to interstate crude pipelines and, thus, make interstate movements of crude oil. We presently anticipate such movements would also qualify for 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 the transportation on these pipelines is within its jurisdiction. In the event that FERC were to determine that one or both of these pipelines no longer qualified for waiver, we would likely be required to file a tariff with FERC for one or both of these pipelines, as applicable, 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.

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 $1 million per day for violations of the NGA and $1 million per violation per day 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.

Environmental and Operational Health and Safety Matters

General

Our operations are subject to numerous federal, tribal, state and local laws and regulations governing the discharge of materials into the environment, worker health and safety, or otherwise relating to environmental protection. As with the industry generally, compliance with current and anticipated environmental laws and regulations increases our overall cost of business, including our costs to construct, maintain, upgrade and decommission equipment and facilities. 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 laws and regulations. The trend in environmental regulation is to place more restrictions and limitations on activities that may adversely affect the environment and thus, any changes in environmental laws and regulations or reinterpretation of enforcement policies that result in more stringent and costly waste management or disposal, pollution control or remediation requirements could have a material adverse effect on our operations and financial position. We may be unable to pass on such increased compliance costs 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. See Risk Factor "Failure to comply with environmental laws or regulations or an accidental release into the environment may cause us to incur significant costs and liabilities" under Item 1A of this Form 10-K for further discussion on environmental compliance matters. See "Item 3. Legal Proceedings – Environmental Proceedings" for a discussion of certain recent or pending proceedings related to environmental matters.

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 become material in the future. The following is a summary of the more significant existing environmental and worker health and safety laws and regulations, as amended from time to time, to which our business operations are subject and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

Hazardous Substances and Waste

The Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), and comparable state laws impose joint and several, strict liability on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include current and prior owners or operators of the site where the release occurred and entities that disposed or arranged for the disposal of the hazardous substances found at the site. Liability of these "responsible persons" under CERCLA may include the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the U.S. Environmental Protection Agency ("EPA") and, in some instances, third-parties to act in response to threats to the public health or the environment and to seek to recover from these responsible persons the costs they incur. It is not uncommon for neighboring landowners and other third-parties to file claims under CERCLA for personal injury and property damage allegedly caused by the release of hazardous substances into the environment. We generate materials in the course of our operations that are regulated as "hazardous substances" under CERCLA or similar state statutes and, as a result, may be jointly and severally liable under CERCLA or similar state statutes for all or part of the costs required to clean up releases of hazardous substance into the environment.

We also generate solid wastes, including hazardous wastes that are subject to the Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. While RCRA regulates both solid and hazardous wastes, it imposes additional stringent requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. In the course of our operations, we generate petroleum product wastes and ordinary industrial wastes that are regulated as hazardous wastes. Although certain materials generated in the exploration, development or production of crude oil and natural gas are excluded from RCRA's hazardous waste regulations, there have been efforts from time to time to remove this exclusion. For example, in response to a lawsuit filed by several non-governmental environmental groups against the EPA for the agency's failure to timely assess its RCRA Subtitle D criteria regulations for oil and gas wastes, the EPA and the environmental groups entered into an agreement that was finalized in a consent decree issued by the U.S. District Court for the District of Columbia in December 2016. Under the decree, the EPA is required to propose no later than March 15, 2019, a rulemaking for revision of certain Subtitle D criteria regulations pertaining to oil and gas wastes or sign a determination that revision of the regulations is not necessary. If EPA proposes a rulemaking for revised oil and gas waste regulations, the Consent Decree requires that the EPA take final action following notice and comment rulemaking no later than July 15, 2021. Any future changes in law or regulation that result in these wastes, including wastes currently generated during our or our customers' operations, being designated as "hazardous wastes" and therefore subject to more rigorous and costly disposal requirements, could have a material adverse effect on our capital expenditures and operating expenses and, with respect to such adverse effects on our customers, could reduce the demand for our services.

We currently own or lease, and have in the past owned or leased, properties that for many years have been used for midstream natural gas, NGL and crude oil activities and refined petroleum product and crude oil storage and terminaling activities. Hydrocarbons or other substances and wastes may have been released on or under the properties owned or leased by us or on or under the other locations where these hydrocarbons or other substances and wastes have been taken for treatment or disposal. In addition, certain of these properties have been operated by third parties whose treatment and release of hydrocarbons or other substances and wastes was not under our control. These properties and any hydrocarbons, substances and wastes released thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) and to perform remedial operations to prevent future contamination, the costs of which activities could have a material adverse effect on our business and results of operations.

Air Emissions

The federal Clean Air Act (“CAA”) and comparable state laws and regulations restrict the emission of air pollutants from many sources, including processing plants and compressor stations and also impose various monitoring and reporting requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions. The need to obtain permits has the potential to delay the development of oil and natural gas related projects. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. For example, in 2015, the EPA issued a final rule under the CAA, lowering the National Ambient Air Quality Standard 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. The EPA published a final rule in November 2017 that issued area designations with respect to ground-level ozone for approximately 85% of the U.S. counties as either “attainment/unclassifiable” or “unclassifiable” and is expected to issue non-attainment designations for the remaining areas of the U.S. not addressed under the November 2017 final rule in the first half of 2018. Also, states are expected to implement more stringent regulations, which could apply to our operations. Additionally, in June 2016, the EPA (1) published a final rule updating federal permitting regulations for stationary sources in the oil and natural gas industry by defining and clarifying the meaning of the term “adjacent” for determining when separate surface sites and the equipment at those sites will be aggregated for permitting purposes; and (2) published a final Federal Implementation Plan to implement a minor new source review permitting program for oil and natural gas stationary sources on certain Indian reservations, including the Fort Berthold Indian Reservation in North Dakota. Compliance with these or other new regulations could, among other things, require installation of new emission controls on some of our equipment, result in longer permitting timelines, and significantly increase our capital expenditures and operating costs, which could adversely impact our business.

Climate Change

The EPA has determined that greenhouse gas (“GHG”) emissions endanger public health and the environment because emissions of such gases are contributing to warming of the earth’s atmosphere and other climatic changes. Based on these findings, the EPA has adopted regulations under the CAA related to GHG emissions. See Risk Factor “The adoption and implementation of climate change legislation and 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 Form 10-K for further discussion on climate change and regulation of GHG emissions.

Water Discharges

The Federal Water Pollution Control Act ("Clean Water Act" or "CWA") and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into navigable waters. Pursuant to the CWA and analogous state laws, permits must be obtained to discharge pollutants into state waters or waters of the United States. Any such discharge of pollutants into regulated waters must be performed in accordance with the terms of the permit issued by the EPA or the analogous state agency. Spill prevention, control and countermeasure requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities and such permits may require us to monitor and sample the storm water runoff. The CWA also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by permit. The CWA and analogous state laws also may impose substantial civil and criminal penalties for non-compliance including spills and other non-authorized discharges.

In June 2015, the EPA and the U.S. Army Corps of Engineers (the "Corps") published a final rule attempting to clarify the federal jurisdictional reach over waters of the United States, including wetlands, but legal challenges to this rule followed. The June 2015 rule was stayed nationwide to determine whether federal district or appellate courts had jurisdiction to hear cases in the matter and, in January 2017, the U.S. Supreme Court agreed to hear the case. Recently, on January 22, 2018, the U.S. Supreme Court issued a decision finding that jurisdiction resides with the federal district courts; consequently, while implementation of the June 2015 rule currently remains stayed, the previously filed district court cases will be allowed to proceed. Additionally, the EPA and Corps proposed a rulemaking in June 2017 to repeal the June 2015 rule, and announced their intent to issue a new rule defining the scope of the Clean Water Act's jurisdiction. Further, in November 2017, the EPA and the Corps published a proposed rule specifying that the contested June 2015 rule will not take effect until two years after the November 2017 proposed rule is finalized and published in the Federal Register. As a result, future implementation of the June 2015 rule is uncertain at this time. To the extent this rule or a revised rule expands the scope of the CWA's jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas in connection with any expansion activities.

The Federal Oil Pollution Act of 1990 ("OPA") which amends the CWA, establishes strict liability for owners and operators of facilities that are the site of a release of oil into waters of the United States. The OPA and its associated regulations impose a variety of requirements on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills. A "responsible party" under the OPA includes owners and operators of onshore facilities, such as our plants and our pipelines. Under the OPA, owners and operators of facilities that handle, store, or transport oil are required to develop and implement oil spill response plans, and establish and maintain evidence of financial responsibility sufficient to cover liabilities related to an oil spill for which such parties could be statutorily responsible.

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and chemical additives under pressure into rock formations to stimulate gas production. The process is typically regulated by state oil and gas commissions, but several federal agencies, including the EPA and the BLM have asserted regulatory authority over aspects of the process. Also, Congress has considered, and some states and local governments have adopted legal requirements that could impose more stringent permitting, disclosure or well construction requirements on hydraulic fracturing activities. While we do not conduct hydraulic fracturing, if new or more stringent federal, state, or local legal restrictions or prohibitions relating to the hydraulic fracturing process are adopted in areas where our oil and natural gas exploration and production customers operate, those customers could incur potentially significant added costs to comply with such requirements and experience delays or curtailment in the pursuit of exploration, development or production activities, which could reduce demand for our gathering, processing and fractionation services. See Risk Factor "Increased regulation of hydraulic fracturing could result in reductions or delays in drilling and completing new oil and natural gas wells, 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" under Item 1A of this Form 10-K for further discussion on hydraulic fracturing.

Endangered Species Act Considerations

The federal Endangered Species Act ("ESA") restricts activities that may affect endangered or threatened species or their habitats. Some of our facilities may be located in areas that are designated as habitat for endangered or threatened species. If endangered species are located in areas of the underlying properties where we plan to conduct development activities, such work could be prohibited or delayed or expensive mitigation may be required. Similar protections are offered to migrating birds under the federal Migratory Bird Treaty Act. Moreover, as a result of one or more settlements approved by the federal government, the U.S. Fish and Wildlife Service ("FWS") must make determinations within specified timeframes on the listing of numerous species as endangered or threatened under the ESA. The designation of previously unprotected species as threatened or endangered in areas where we or our customers operate could cause us or our customers to incur increased costs arising from species protection measures and could result in delays or limitations in our customers' performance of operations, which could reduce demand for our services. Certain of our operations occur within areas of American Burying Beetle habitat. In July 2017, the FWS issued Incidental Take Permits to certain of our subsidiaries operating in Oklahoma that requested participation in the Amended Oil and Gas Industry Conservation Plan Associated with Issuance of Endangered Species Act Section 10(a)(1)(B) Permits for the American Burying Beetle in Oklahoma.

Employee Health and Safety

We are subject to a number of 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. On November 24, 2017, OSHA published a final rule in the Federal Register delaying the initial compliance deadline for the electronic submission of worker injury and illness logs to December 15, 2017. We have timely complied with these electronic reporting requirements. We and the entities in which we own an interest are also 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. We have implemented an internal program of inspection designed to monitor and pursue operations in a manner consistent with worker safety requirements.

Pipeline Safety Matters

Many of our natural gas, NGL and crude pipelines are subject to regulation by the Pipeline and Hazardous Materials Safety Administration ("PHMSA"), an agency under the DOT (or state analogs), 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 wall thicknesses, design pressures, maximum operating pressures, pipeline patrols and leak surveys, 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 for certain natural gas and hazardous liquids pipelines that, in the event of a pipeline leak or rupture, could affect "high consequence areas," which are areas where a release could have the most significant adverse consequences, including high-population areas, certain drinking water sources and unusually sensitive ecological areas. In the past, we have not incurred material costs in connection with complying with these NGPSA and HLPSA requirements. If, however, PHMSA imposes new or amended regulations, reinterprets or changes enforcement practices, or revises or issues new guidance with respect thereto, future compliance with the NGPSA and HLPSA could result in increased costs that could have a material adverse effect on our results of operations or financial position.

The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 ("2011 Pipeline Safety Act"), which became law in January 2012, amended the NGPSA and HLPSA by increasing the penalties for safety violations, establishing additional safety requirements for newly constructed pipelines and requiring studies of safety issues that could result in the adoption of new regulatory requirements for existing pipelines. In June 2016, President Obama signed the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016 ("2016 Pipeline Safety Act"), further amending the NGPSA and HLPSA, extending PHMSA's statutory mandate through 2019 and, among other things, requires PHMSA to complete certain of its outstanding mandates under the 2011 Pipeline Safety Act and develop new safety standards for natural gas storage facilities by June 22, 2018. The 2016 Pipeline Safety Act also empowers PHMSA to address 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. PHMSA published an interim rule in October 2016 to implement the agency's expanded authority to address unsafe pipeline conditions or practices that pose an imminent hazard to life, property, or the environment.

We, or the entities in which we own an interest, inspect our pipelines regularly in a manner consistent with state and federal maintenance requirements. Nonetheless, the adoption of new or amended regulations by PHMSA that result in more stringent or costly pipeline integrity management or safety standards could have a significant adverse effect on us. The safety enhancement requirements and other provisions of the 2016 Pipeline Safety Act as well as any implementation of PHMSA rules thereunder 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 or operational delays that could have a material adverse effect on our results of operations or financial position.

In addition, states have adopted regulations, similar to existing PHMSA regulations, for intrastate gathering and transmission lines. Texas, Louisiana and New Mexico, for example, have developed regulatory programs that parallel the federal regulatory scheme and are applicable to intrastate pipelines transporting natural gas, NGLs and crude oil. North Dakota has similarly implemented regulatory programs applicable to intrastate natural gas pipelines. We currently estimate an annual average cost of $3.3 million for the years 2018 through 2020 to perform necessary integrity management program testing on our pipelines required by existing PHMSA and state regulations. This estimate does not include the costs, if any, of any repair, remediation, or preventative or mitigating actions that may be determined to be necessary as a result of the testing program, which costs could be substantial. However, we do not currently expect that any such costs would be material to our 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

Through a wholly-owned subsidiary of ours, we employ approximately 2,130 people who primarily support our operations. None of those employees are covered by collective bargaining agreements. We consider our employee relations to be good.

Financial Information by Reportable Segment

See "Segment Information" included under Note 26 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– 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. The filings are also available through the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549 or by calling 1-800-SEC-0330. Also, these filings are available on the internet at http://www.sec.gov. Our press releases and recent analyst presentations are also available on our website.

Item 1A. Risk Factors.

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, 2017, we had $4,223.0 million outstanding under the Partnership's senior unsecured notes and $54.6 million of outstanding senior notes of TPL, excluding $0.4 million of unamortized net discounts and premiums. We also had $350.0 million outstanding under the Partnership's Securitization Facility. In addition, we had (i) $20.0 million of borrowings outstanding, $27.2 million of letters of credit outstanding and $1,552.8 million of additional borrowing capacity available under the TRP Revolver, (ii) $435.0 million of borrowings outstanding, and $235.0 million of additional borrowing capacity available under the TRC Revolver. For the years ended December 31, 2017, 2016 and 2015, our consolidated interest expense, net was $233.7 million, $254.2 million and $231.9 million.

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 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, 2017, the Partnership's senior unsecured debt was rated "BB-" by S&P. As of December 31, 2017, the Partnership'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 dividends. 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 and TRC Revolver allow us to request increases in commitments up to an additional $500 million and $200 million, respectively. 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 and may cause the market price of our common stock to decline.

We have significant exposure to increases in interest rates. As of December 31, 2017, our total indebtedness was $5,082.6 million, excluding $0.4 million of net premiums and $30.0 million of net debt issuance costs, of which $4,277.6 million was at fixed interest rates and $805.0 million was at variable interest rates. 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 $8.1 million. As a result of this amount of variable interest rate debt, our financial condition could be negatively affected by increases in interest rates.

Additionally, like all equity investments, an investment in our common stock is subject to certain risks. In exchange for accepting these risks, investors may expect to receive a higher rate of return than would otherwise be obtainable from lower-risk investments. Accordingly, as interest rates rise, the ability of investors to obtain higher risk-adjusted rates of return by purchasing government-backed debt securities may cause a corresponding decline in demand for riskier investments generally, including yield-based equity investments. Reduced demand for our common stock resulting from investors seeking other more favorable investment opportunities may cause the trading price of our common stock to decline.

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, including to pay dividends to our stockholders

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 stock;
- pay dividends 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 the Partnership's 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 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 operations can be affected by the level of natural gas and NGL 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. Beginning in the third quarter of 2014, crude oil and natural gas prices significantly declined and continued to decline during 2015 and remained depressed in 2016 before starting to recover in 2017. 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. For the year ended December 31, 2017, our percent-of-proceeds arrangements accounted for approximately 59.9% of our gathered natural gas volume. 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.”

In the future, we may not have sufficient cash to pay estimated dividends.

Factors such as reserves established by our board of directors for our estimated general and administrative expenses as well as other operating expenses, reserves to satisfy our debt service requirements, if any, and reserves for future dividends by us may affect the dividends we make to our stockholders. The actual amount of cash that is available for dividends to our stockholders will depend on numerous factors, many of which are beyond our control.

Our cash dividend policy limits our ability to grow.

Because we may distribute a substantial amount of our cash flow, our growth may not be as fast as the growth of businesses that reinvest their available cash to expand ongoing operations. If we issue additional shares of common or preferred stock or we incur debt, the payment of dividends on those additional shares or interest on that debt could increase the risk that we will be unable to maintain or increase our cash dividend levels.

If dividends on our shares of common stock are not paid with respect to any fiscal quarter, our stockholders will not be entitled to receive that quarter's payments in the future.

Dividends to our common stockholders are not cumulative. Consequently, if dividends on our shares of common stock are not paid with respect to any fiscal quarter, our stockholders will not be entitled to receive that quarter's payments in the future.

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

We evaluate goodwill for impairment at least annually, as of November 30, as well as whenever events or changes in circumstances indicate it is more likely than not the fair value of a reporting unit is less than its carrying amount. During 2015, global oil and natural gas commodity prices, particularly crude oil, significantly decreased as compared to 2014, and such prices remained depressed in 2016 with some recovery in 2017. This decrease in commodity prices has had, and could continue to have, a negative impact on the demand for our services and our market capitalization.

Should energy industry conditions further deteriorate, there is a possibility that goodwill 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 goodwill. For a further discussion of our goodwill impairments, see Note 7 - Goodwill 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 pay cash dividends to our stockholders.

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 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. Beginning in the third quarter of 2014, crude oil and natural gas prices significantly declined and continued to decline during 2015 and remained depressed in 2016 before starting to recover in 2017. 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 (including the Permian Acquisition and our recently announced Grand Prix and GCX joint ventures) are subject to substantial risks that could adversely affect our financial condition and results of operations and reduce our ability to pay dividends to stockholders. In addition, we may not achieve the expected results of the Permian Acquisition and any adverse conditions or developments related to the Permian Acquisition 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 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 dividends will be limited.

Any acquisition (including the Permian Acquisition) or growth project (including Grand Prix and GCX) 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 to pay cash dividends to our stockholders.

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. 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 such rights of way to connect new natural gas 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.

Demand for propane is significantly impacted by weather conditions and therefore seasonal and requires increases in inventory to meet seasonal demand.

Weather conditions have a significant impact on the demand for propane because domestic end-users principally utilize propane for heating purposes. Warmer-than-normal temperatures in one or more regions in which we operate can significantly decrease the total volume of propane we sell. Lack of consumer domestic demand for propane may also adversely affect the retailers with which we transact our wholesale propane marketing operations, exposing us to retailers' inability to satisfy their contractual obligations to us.

If we lose any of our named executive officers, our business may be adversely affected.

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

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 and future commodity purchases and sales. 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 at its highest during the six-month peak heating season of October through March. Demand for our propane may be reduced during periods of 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.

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.

The duties of our officers and directors may conflict with those owed to the Partnership.

Substantially all of our officers and all the members of our board of directors are officers and/or directors of the general partner and, as a result, have separate duties that govern their management of the Partnership’s business. These officers and directors may encounter situations in which their obligations to us, on the one hand, and the Partnership, on the other hand, are in conflict. The resolution of these conflicts may not always be in our best interest or that of our stockholders. For a discussion of our officers and directors that will serve in the same capacity for the general partner and the amount of time we expect them to devote to our business, please read “Management.”

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

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

In connection with the issuance of the Preferred Shares, we entered into an agreement with Stonepeak Target Holdings, LP pursuant to which we granted them the right to appoint an observer to our Board of Directors, such observer having the right to become a member of our Board of Directors under certain circumstances. In addition, the Certificate of Designations governing the Preferred Shares provides the holders of the Preferred Shares with the right to vote, under certain conditions, on an as-converted basis with our common stockholders on matters submitted to a stockholder vote. The holders of the Preferred Shares do not currently have such right to vote. Also, so long as any Preferred Shares are outstanding, subject to certain exceptions, the affirmative vote or consent of the holders of at least a majority of the outstanding Preferred Shares, voting together as a separate class, will be necessary for effecting or validating, among other things: (i) any issuance of stock senior to the Preferred Shares, (ii) any issuance or increase by any of our consolidated subsidiaries of any issued or authorized amount of, any specific class or series of securities, (iii) any issuance by us of parity stock, subject to certain exceptions and (iv) any incurrence of indebtedness by us and our consolidated subsidiaries for borrowed monies, other than under our existing credit agreement and the Partnership's existing credit agreement (or replacement commercial bank credit facilities) in an aggregate amount up to $2.75 billion, or indebtedness that complies with a specified fixed charge coverage ratio. These restrictions may adversely affect our ability to finance future operations or capital needs or to engage in other business activities.

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

The tax treatment of the Partnership depends on its status as a partnership for U.S. federal income tax purposes as well as its not being subject to a material amount of entity-level taxation by individual states. If, upon an audit of the Partnership, the Internal Revenue Service ("IRS") were to treat the Partnership as a corporation for federal income tax purposes now or with respect to a tax period prior to the TRC/TRP Merger, or the Partnership becomes subject to a material amount of entity-level taxation for state tax purposes, then its cash available for distribution to us would be substantially reduced.

A publicly traded partnership such as the Partnership may be treated as a corporation for federal income tax purposes unless it satisfies a "qualifying income" requirement. Based on the Partnership's current operations we believe that the Partnership satisfies 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 the Partnership to be treated as a corporation for federal income tax purposes or otherwise subject the Partnership to taxation as an entity. The Partnership has not requested and does not plan to request a ruling from the IRS with respect to its treatment as a partnership for federal income tax purposes.

If the Partnership were treated as a corporation for federal income tax purposes, it would pay federal income tax on its 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 from the Partnership would generally be taxed again as corporate distributions and no income, gains, losses or deductions would flow through to us. If such tax were imposed upon the Partnership as a corporation now or with respect to a tax period prior to the TRC/TRP Merger, its cash available for distribution would be substantially reduced. Therefore, treatment of the Partnership as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to us and could cause a substantial reduction in the value of our shares.

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, the Partnership is subject to the Texas franchise tax at a maximum effective rate of 0.75% of its gross income apportioned to Texas in the prior year. Imposition of any similar tax on the Partnership by additional states would reduce the cash available for distribution to us.

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

The present U.S. federal income tax treatment of publicly traded partnerships, including the Partnership, or an investment in the Partnership may be modified by administrative, legislative or judicial changes or differing interpretations at any time. For example, from time to time, members of Congress propose and consider such substantive changes to the existing federal income tax laws that affect publicly traded partnerships. One such legislative proposal would have eliminated the qualifying income exception to the treatment of all publicly traded partnerships as corporations, upon which the Partnership relies for its treatment as a partnership for U.S. federal income tax purposes.

Any modification to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible for the Partnership 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 changes could negatively impact the value of our shares.

On January 24, 2017, final regulations regarding which activities give rise to qualifying income within the meaning of Section 7704 of the Code (the "Final Regulations") were published in the Federal Register. The Final Regulations are effective as of January 19, 2017, and apply to taxable years beginning on or after January 19, 2017. We do not believe the Final Regulations affect the Partnership's ability to be treated as a partnership for U.S. federal income tax purposes.

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, following a recent decision issued in May 2017 by the federal Tenth Circuit Court of Appeals, 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.

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.

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. For example, unseasonably wet weather, extended periods of below freezing weather, or hurricanes may cause disruptions or suspensions of our operations, which could adversely affect our operating results. 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.

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 damage, and may result in 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. During 2017, we had minimal direct losses as a result of Hurricane Harvey.

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, as amended from time to time, 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 "high consequence areas," which are areas where a release could have the most significant adverse consequences, including high-population areas, certain drinking water sources and unusually sensitive ecological areas. 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 a high consequence area;

- improve data collection, integration and analysis;
- repair and remediate the pipeline as necessary; and
- implement preventive and mitigating actions.

In addition, states 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 $3.3 million between 2018 and 2020 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 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 will 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 example, in January 2017, PHMSA issued a final rule for hazardous liquid pipelines that significantly extends and expands the reach of certain PHMSA integrity management requirements, such as, for example, periodic assessments, leak detection and repairs, regardless of the pipeline's proximity to a high consequence area. The final rule also requires all pipelines in or affecting a high consequence area to be capable of accommodating in-line inspection tools within the next 20 years. In addition, the final rule extends annual and accident reporting requirements to gravity lines and all gathering lines and also imposes inspection requirements on 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. The timing for implementation of this rule has been delayed and remains uncertain at this time due to the change in U.S. Presidential administrations. In a second example, in March 2016, PHMSA announced a proposed rulemaking that would impose new or more stringent requirements for certain natural gas lines and gathering lines, including, among other things, the imposition of increased integrity management requirements. PHMSA has not yet finalized the March 2016 proposed rulemaking. Such legislative and regulatory changes could have a material effect on our operations and costs of transportation services.

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.

Failure to comply with environmental laws or regulations 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 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 analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits 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 delays 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 waste have been released by a predecessor operator or the activities conducted and from which a release emanated complied with applicable law.

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. The adoption of any laws, regulations or other legally enforceable mandates that result in more stringent air emission limitations or that restrict or prohibit the drilling of new oil or natural gas wells for any extended period of time could increase our oil and natural gas customers' operating and compliance costs as well as reduce the rate of production of natural gas or crude oil from operators with whom we have a business relationship, which could have a material adverse effect on our results of operations and cash flows. See "Item 1. Business –Regulation of Operations—Environmental and Operational Health and Safety Matters" for additional information regarding regulatory developments with respect to environmental regulations.

Increased regulation of hydraulic fracturing could result in reductions or delays in drilling and completing new oil and natural gas wells, 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 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 and the BLM. For example, in December 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. 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. States could elect to prohibit high volume hydraulic fracturing altogether, following the approach taken by the State of 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. New or more stringent laws or regulations 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, 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, our natural gas pipeline operations are generally exempt from FERC regulation under the NGA, 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.

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 to impose penalties for current violations of up to $1 million 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 as a natural gas company under the NGA, 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. For more information regarding regulation of our operations, see "Item 1. Business—Regulation of Operations."

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.

Climate change continues to attract considerable public and scientific attention. 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 emissions of GHGs. These efforts have included consideration of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs, and regulations that directly limit GHG emissions from certain sources.

At the federal level, no comprehensive climate change legislation has been implemented to date. However, the EPA has adopted rules under authority of the CAA that, among other things, establish Potential for Significant Deterioration (PSD) construction and Title V operating permit reviews for GHG emissions from certain large stationary sources that are also potential major sources of certain principal, or criteria, pollutant emissions, which reviews could require securing PSD permits at covered facilities emitting GHGs and meeting "best available control technology" standards for those GHG emissions. The EPA has also adopted rules requiring the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the United States, including, among others, onshore processing, transmission, storage and distribution facilities. In October 2015, the EPA amended and expanded the GHG reporting requirements to all segments of the oil and natural gas industry, including gathering, compression and boosting facilities as well as blowdowns of natural gas transmission pipelines, and in January 2016, the EPA proposed additional revisions to leak detection methodology to align the reporting rules with the new source performance standards.

Federal agencies also have begun directly regulating emissions of methane, a GHG, from oil and natural gas operations. For example, in June 2016, the EPA published New Source Performance Standards, known as Subpart OOOOa, that require certain new, modified or reconstructed facilities in the oil and natural gas sector to reduce these methane gas and volatile organic compound emissions. These Subpart OOOOa standards will expand previously issued New Source Performance Standards published by the EPA in 2012 and known as Subpart OOOO, by using certain equipment-specific emissions control practices, requiring additional controls for pneumatic controllers and pumps as well as compressors, and imposing leak detection and repair requirements for natural gas compressor and booster stations. However, the EPA proposed rulemaking in June 2017 to stay certain requirements of Subpart OOOOa for a period of two years and revisit implementation of Subpart OOOOa in its entirety. The EPA has not yet published a final rule but, as a result of these developments, future implementation of the 2016 Subpart OOOOa standards is uncertain. Because of the long-term trend toward increasing regulation, however, future federal GHG regulations of the oil and natural gas industry remain a possibility.

On the international level, in December 2015, the U.S. joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France that prepared an agreement requiring member countries to review and “represent a progression” in their intended nationally determined contributions, which set GHG emission reduction goals every five years beginning in 2020. This “Paris Agreement” was signed by the United States in April 2016 and entered into force in November 2016; however, this agreement does not create any binding obligations for nations to limit their GHG emissions, but does include pledges to voluntarily limit or reduce future emissions. However, in August 2017, the U.S. State Department officially informed the United Nations of the intent of the United States to withdraw from the Paris Agreement. The Paris Agreement provides for a four-year exit process beginning when it took effect in November 2016, which would result in an effective exit date of November 2020. The United States’ adherence to the exit process and/or the terms on which the United States may re-enter the Paris Agreement or a separately negotiated agreement are unclear at this time.

The adoption and implementation of any international, federal or state legislation or regulations that require reporting of GHGs or otherwise restrict emissions of GHGs could result in increased compliance costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, oil and natural gas, which could reduce demand for our products and services. One or more of these developments could have a material adverse effect on our business, financial condition and results of operation. Recently, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult to secure funding for exploration and production or midstream activities. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to rise and will not peak until after 2040 and that oil and natural gas will continue to represent a substantial percentage of global energy use over that time. Finally, some scientists have concluded that increasing concentrations of GHG in the atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climate events.

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.

In June 2016, President Obama signed the 2016 Pipeline Safety Act that extends PHMSA’s statutory mandate regarding pipeline safety through 2019 and requires PHMSA to complete certain of its outstanding mandates under the 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 called for the development of new safety standards for natural gas storage facilities by June 22, 2018, and empowered PHMSA to address 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.

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. For example, in March 2016, PHMSA announced a proposed rulemaking that would impose new or more stringent requirements for certain natural gas lines and gathering lines including, among other things, expanding certain of PHMSA's current regulatory safety programs for natural gas pipelines in newly defined "moderate consequence areas" that contain as few as 5 dwellings within a potential impact area; requiring natural gas pipelines installed before 1970 and thus excluded from certain pressure testing obligations to be tested to determine their maximum allowable operating pressures ("MAOP"); requiring certain onshore and offshore gathering lines in Class I areas to comply with damage prevention, corrosion control, public education, MAOP limits, line markers and emergency planning standards; and requiring consideration of seismicity in evaluating threats to pipelines. In another example, effective April 2017, PHMSA adopted a final rule increasing the maximum administrative civil penalties for violation of the pipeline safety laws and regulations to $209,002 per violation per day and up to $2,090,022 for a related series of violations. 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. The safety enhancement requirements and other provisions of the 2016 Pipeline Safety Act as well as any implementation of PHMSA rules thereunder 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 or operational delays that could have a material adverse effect on our results of operation 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, 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.

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 November 2013, 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. The rules were re-proposed in December 2016. 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. In addition, for uncleared swaps, the CFTC or federal banking regulators may require end-users to enter into credit support documentation and/or post initial and variation margin in the future, although current rules do not result in requirements for our swap dealer counterparties to collect margin from us for our hedging transactions. Posting of collateral could impact liquidity and reduce cash available to us for capital expenditures, therefore reducing our ability to execute hedges to reduce risk and protect cash flows.

The Dodd-Frank Act also may require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty.

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.

Our interstate common carrier liquids pipelines are regulated by the FERC.

Targa NGL has interstate NGL pipelines that are considered common carrier pipelines subject to regulation by FERC under the ICA. More specifically, Targa NGL owns a twelve-inch diameter pipeline that runs between Lake Charles, Louisiana and Mont Belvieu, Texas. This pipeline can move mixed NGL and purity NGL products. Targa NGL also owns an eight-inch diameter pipeline and a twenty-inch diameter pipeline, each of which run between Mont Belvieu, Texas and Galena Park, Texas. The eight-inch and the twenty-inch pipelines are 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. In 2018, Targa NGL will complete another pipeline for exports at Targa's Galena Park dock.

Additionally, we expect to begin operating portions of the Grand Prix pipeline in 2018, which would transport mixed NGLs from the Permian Basin, including points in New Mexico and Texas, to intermediate points in Texas, and beginning in 2019, to Mont Belvieu, Texas. The ICA requires that we maintain tariffs on file with FERC for each of these pipelines. 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 nondiscriminatory. Several of these pipelines would qualify for a waiver of filing of the FERC tariffs.

Targa NGL also owns a twelve-inch diameter pipeline that runs between Mont Belvieu, Texas, and Galena Park, Texas, that transports NGLs and that has qualified for a waiver of applicable FERC regulatory requirements under the ICA based on current circumstances. The crude oil pipeline system that is part of the Badlands assets also qualifies for such a waiver. Although we do not presently make any interstate movements on our Texas crude oil pipeline system, in the future we could construct new pipelines that connect to interstate crude pipelines and, thus, make interstate movements of crude oil. We presently anticipate such movements would also qualify for a waiver.

All such waivers are subject to revocation, however, and should a particular pipelines' circumstances change, FERC could, either at the request of other entities or on its own initiative, assert that some or all of the transportation on these pipelines is within its jurisdiction. In the event that FERC were to determine that one or both of these pipelines no longer qualified for a waiver, the Partnership would likely be required to file a tariff with FERC for one or both of these pipelines, as applicable, 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.

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 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 certain processing activities. For example, we depend on digital technologies to perform many of our services and to process and record financial and operating 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 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 other disruption of business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period. Our systems and insurance coverage 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 continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber incidents. Our insurance coverage for cyberattacks may not be sufficient to cover all the losses we may experience as a result of such cyberattacks.

Future sales of our common stock in the public market could lower our stock price, and any additional capital raised by us through the sale of equity or convertible securities may dilute your ownership in us.

We or our stockholders may sell shares of common stock in subsequent public offerings. We may also issue additional shares of common stock or convertible securities. As of December 31, 2017, we had 217,566,980 outstanding shares of common stock. We cannot predict the size of future issuances of our common stock or the effect, if any, that future issuances and sales of shares of our common stock will have on the market price of our common stock. Sales of substantial amounts of our common stock (including shares issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices of our common stock.

Our amended and restated certificate of incorporation and amended and restated bylaws, as well as Delaware law, contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our common stock.

Our amended and restated certificate of incorporation authorizes our board of directors to issue preferred stock without stockholder approval. If our board of directors elects to issue preferred stock, it could be more difficult for a third-party to acquire us. In addition, some provisions of our amended and restated certificate of incorporation and amended and restated bylaws could make it more difficult for a third-party to acquire control of us, even if the change of control would be beneficial to our stockholders, including provisions which require:

- a classified board of directors, so that only approximately one-third of our directors are elected each year;
- limitations on the removal of directors; and
- limitations on the ability of our stockholders to call special meetings and establish advance notice provisions for stockholder proposals and nominations for elections to the board of directors to be acted upon at meetings of stockholders.

Delaware law prohibits us from engaging in any business combination with any “interested stockholder,” meaning generally that a stockholder who beneficially owns more than 15% of our stock cannot acquire us for a period of three years from the date this person became an interested stockholder, unless various conditions are met, such as approval of the transaction by our board of directors. Please read "Description of Our Capital Stock—Anti-Takeover Effects of Provisions of Our Amended and Restated Certificate of Incorporation, Our Amended and Restated Bylaws and Delaware Law."

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 by this item is included in Note 20 – Contingencies in our Consolidated Financial Statements, and is incorporated herein by reference thereto.

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

Our common stock is listed on the NYSE under the symbol "TRGP." As of December 31, 2017, there were approximately 246 stockholders of record of our common stock. This number does not include stockholders whose shares are held in trust by other entities. The actual number of stockholders is greater than the number of holders of record. As of February 12, 2018, there were 218,830,282 shares of common stock outstanding.

The following table sets forth the high and low sales prices of our common stock as reported by the NYSE and the amount of cash dividends declared for the periods indicated:

	Share Prices		
Quarter Ended	High	Low	Dividend per Share
December 31, 2017	$48.45	$39.59	$0.9100
September 30, 2017	48.73	42.49	0.9100
June 30, 2017	60.62	40.25	0.9100
March 31, 2017	61.83	53.74	0.9100
December 31, 2016	59.35	41.35	0.9100
September 30, 2016	50.87	35.35	0.9100
June 30, 2016	45.64	27.09	0.9100
March 31, 2016	31.41	14.55	0.9100
December 31, 2015	66.87	23.33	0.9100
September 30, 2015	92.13	48.65	0.9100
June 30, 2015	108.63	87.09	0.8750
March 31, 2015	107.93	82.09	0.8300

Stock Performance Graph

The graph below compares the cumulative return to holders of Targa Resources Corp.'s common stock, the NYSE Composite Index (the "NYSE Index") and the Alerian MLP Index (the "MLP Index"). The performance graph was prepared based on the following assumptions: (i) $100 was invested in our common stock at $24.70 per share (the closing market price at the end of our first trading day), in the NYSE Index, and the MLP Index on December 7, 2010 (our first day of trading) and (ii) dividends were reinvested on the relevant payment dates. The stock price performance included in this graph is historical and not necessarily indicative of future stock price performance.

Pursuant to Instruction 7 to Item 201(e) of Regulation S-K, the above stock performance graph and related information is being furnished and is not being filed with the SEC, and as such shall not be deemed to be incorporated by reference into any filing that incorporates this Annual Report by reference.

Our Dividend Policy

We intend to pay to our stockholders, on a quarterly basis, dividends funded primarily by the cash that we receive from our operations, less reserves for expenses, future dividends and other uses of cash, including:

- the proper conduct of our business including reserves for corporate purposes, future capital expenditures and for anticipated future credit needs;
- compliance with applicable law or any loan agreements, security agreements, mortgages, debt instruments or other agreements;

- other general and administrative expenses;
- federal income taxes, which we may be required to pay because we are taxed as a corporation;
- reserves that our board of directors, in consultation with management, believes prudent to maintain; and
- interest expense or principal payments on any indebtedness we incur.

The determination of the amount of cash dividends, including the quarterly dividend referred to above, if any, to be declared and paid will depend upon our financial condition, results of operations, cash flow, the level of our capital expenditures, future business prospects and any other matters that our board of directors, in consultation with management, deems relevant. Further, the Partnership's debt agreements and obligations to its holders of Preferred Units ("Preferred Unitholders") may restrict or prohibit the payment of distributions to us if the Partnership is in default, threat of default, or arrears. If the Partnership cannot make distributions to us, we may be unable to pay dividends on our common stock. In addition, so long as any Preferred Shares are outstanding, certain limitations on our ability to declare dividends on our common stock exist.

Our dividend policy takes into account the possibility of establishing cash reserves in some quarterly periods that we may use to pay cash dividends in other quarterly periods, thereby enabling us to maintain more consistent cash dividend levels even if our business experiences fluctuations in cash from operations due to seasonal and cyclical factors. Our dividend policy also allows us to maintain reserves to provide funding for growth opportunities.

Dividends on our Preferred Shares are cumulative from the last day of the most recent fiscal quarter, and are payable quarterly in arrears on the 45th day after the end of each fiscal quarter when, as and if declared by our board of directors. Dividends on the Preferred Shares are paid out of funds legally available for payment, in an amount equal to an annual rate of 9.5% ($95.00 per share annualized) of $1,000 per Preferred Share, subject to certain adjustments (the "Liquidation Preference"). With respect to any quarter ending on or prior to December 31, 2017, we could have elected, in lieu of paying a dividend, to add the amount that would have been paid as a dividend to the Liquidation Preference. If we were to have made such election, we would have granted to the holders of the Preferred Shares (the "Holders") a corresponding number of additional warrants having the same terms (including exercise price) as the warrants issued on the date of the closing of the transaction pursuant to which the Preferred Shares were issued (the "Closing Date"). Except as set forth in the preceding sentence, if we fail to pay in full to the Holders the required cash dividend for a fiscal quarter, then (i) the amount of such shortfall will continue to be owed by us to the Holders and will accumulate until paid in full in cash, (ii) the Liquidation Preference will be deemed increased by such amount until paid in full in cash and (iii) contemporaneous with increasing the Liquidation Preference by such shortfall, we will grant and deliver to the Holders a corresponding number of additional warrants having the same terms (including exercise price) as the warrants issued on the Closing Date.

Subject to certain exceptions, so long as any Preferred Shares remain outstanding, no dividend or distribution will be declared or paid on, and no redemption or repurchase will be agreed to or consummated of, stock on a parity with the Preferred Shares or our common stock, unless all accumulated and unpaid dividends for all preceding full fiscal quarters (including the fiscal quarter in which such accumulated and unpaid dividends first arose) have been declared and paid.

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 the 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 a discussion of restrictions on our and our subsidiaries' ability to pay dividends or make distributions, please see Note 10 – Debt Obligations in our Consolidated Financial Statements beginning on page F-1 in this Form 10-K for more information.

Dividends on TRC Common Stock

The following table details the dividends declared by us to our common shareholders for the periods presented.

Three Months Ended	Date Paid or To Be Paid	Total Common Dividends Declared	Amount of Common Dividends Paid or To Be Paid	Accrued Dividends (1)	Dividends Declared per Share of Common Stock
(In millions, except per share amounts)					
2017					
December 31, 2017	February 15, 2018	$ 202.4	$ 199.1	$ 3.3	$ 0.91000
September 30, 2017	November 15, 2017	199.0	196.2	2.8	0.91000
June 30, 2017	August 15, 2017	198.6	196.2	2.4	0.91000
March 31, 2017	May 16, 2017	182.8	180.3	2.5	0.91000
2016					
December 31, 2016	February 15, 2017	$ 178.3	$ 176.5	$ 1.8	$ 0.91000
September 30, 2016	November 15, 2016	166.4	164.6	1.8	0.91000
June 30, 2016	August 15, 2016	153.1	151.6	1.5	0.91000
March 31, 2016	May 16, 2016	147.8	146.1	1.7	0.91000
2015					
December 31, 2015	February 9, 2016	$ 51.7	$ 51.0	$ 0.7	$ 0.91000
September 30, 2015	November 16, 2015	51.3	51.0	0.3	0.91000
June 30, 2015	August 17, 2015	49.2	49.0	0.2	0.87500
March 31, 2015	May 18, 2015	46.6	46.4	0.2	0.83000

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

Recent Sales of Unregistered Equity Securities

There were no sales of unregistered equity securities for the year ended December 31, 2017.

Repurchase of Equity by Targa Resources Corp, or Affiliated Purchasers

Period	Total number of shares withheld	Average price per share	Total number of shares purchased	Maximum number of shares that may yet to

	(1)		as part of publicly announced plans	be purchased under the plan
October 1, 2017 - October 31, 2017	130	$ 45.95	—	—
December 1, 2017 - December 31, 2017	4,146	$ 46.36	—	—

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

Item 6. Selected Financial Data.

The following table presents selected historical consolidated financial and operating data of Targa Resources Corp. 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.

	2017	2016	2015	2014	2013
	(In millions, except per share amounts)				
Statement of operations data:					
Revenues	$8,814.9	$6,690.9	$6,658.6	$8,616.5	$6,314.7
Income (loss) from operations	(122.4)	55.8	159.3	640.5	368.2
Net income (loss)	104.2	(159.1)	(151.4)	423.0	201.3
Net income (loss) attributable to common shareholders	(63.4)	(278.1)	58.3	102.3	65.1
Net income (loss) per common share - basic	(0.31)	(1.80)	1.09	2.44	1.56
Net income (loss) per common share - diluted	(0.31)	(1.80)	1.09	2.43	1.55
Balance sheet data (at end of period):					
Total assets	$14,388.6	$12,871.2	$13,211.0	$6,423.5	$6,022.5
Long-term debt	4,703.0	4,606.0	5,718.8	2,855.5	2,963.2
Series A Preferred 9.5% Stock	216.5	190.8	—	—	—
Other:					
Dividends declared per share	$3.6400	$3.6400	$3.5250	$2.8450	$2.2050

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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 report which should be helpful to the reading of our discussion and analysis 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." Also, the Partnership files a separate Annual Report on Form 10-K with the SEC.

Overview

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

We are engaged in the business of:

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

Factors That Significantly Affect Our Results

Our results of operations are impacted by a number of factors, including changes in commodity prices, the volumes that move through our gathering, processing and logistics assets, contract terms, 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)
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
2016			
4th Quarter	$ 2.98	$ 0.53	$47.73
3rd Quarter	2.81	0.45	44.94
2nd Quarter	1.95	0.46	45.59
1st Quarter	2.09	0.36	33.45
2016 Average	2.46	0.45	42.93
2015			
4th Quarter	$ 2.27	$ 0.40	$42.17
3rd Quarter	2.77	0.39	46.44
2nd Quarter	2.65	0.44	57.96
1st Quarter	2.99	0.46	48.57
2015 Average	2.67	0.42	48.79

(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:

2017: 38% ethane, 34% propane, 13% normal butane, 5% isobutane and 10% natural gasoline

2016: 38% ethane, 34% propane, 12% normal butane, 5% isobutane and 11% natural gasoline

2015: 37% ethane, 35% propane, 12% normal butane, 6% 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 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. The current demand for fractionation services has grown, resulting in increases in fractionation fees, reservation fees and contract term. Export services are supported by fee-based contracts whose rates and terms are driven by global LPG demand fundamentals. The Logistics and Marketing 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 and future commodity purchases and sales through 2020 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 as volumes fluctuate through our systems. 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 ours.

General and Administrative Expenses

We perform centralized corporate functions 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 our direct costs of being a separate public reporting company, these costs are reimbursed by the Partnership. 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 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 infrastructure growth capital expenditures. Demand in our Downstream Business for 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. Notably, beginning in the third quarter of 2014, crude oil, natural gas and NGL prices declined significantly primarily due to global supply and demand imbalances. Crude oil, natural gas and NGL prices continued to decline in 2015 and remained depressed in 2016 before starting to recover in 2017. 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 recent volatility in commodity prices, we are uncertain of what pricing and market demand for oil, condensate, NGLs and natural gas will be throughout 2018, 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

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

Our profitability is also impacted by fee-based contracts. Our growing fee-related capital expenditures for pipelines, expansion of our downstream facilities, as well as third-party acquisitions of businesses and assets, will continue to increase the number of our contracts that are fee-based. Fixed fees for services such as fractionation, storage, terminaling and crude oil gathering are not directly tied to changes in market prices for commodities. Nevertheless, a change in unit fees due to market dynamics does affect profitability.

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

Throughput Volumes, Facility Efficiencies and Fuel Consumption

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

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

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

Operating Expenses

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

Capital Expenditures

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

Gross Margin

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

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

Logistics and Marketing segment gross margin consists primarily of :

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

The gross margin impacts of our equity volumes hedge settlements are reported in Other.

Operating Margin

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

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

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

Gross margin and operating margin are non-GAAP measures. The GAAP measure most directly comparable to gross margin and operating margin is net income. Gross margin and operating margin are not alternatives to GAAP net income and have important limitations as analytical tools. Investors should not consider gross margin and operating margin in isolation or as a substitute for analysis of our results as reported under GAAP. Because gross margin and operating margin exclude some, but not all, items that affect net income and are defined differently by different companies in our industry, our definitions of gross margin and operating margin may not be comparable with similarly titled measures of other companies, thereby diminishing their utility. Management compensates for the limitations of gross margin and operating margin as analytical tools by reviewing the comparable GAAP measures, understanding the differences between the measures and incorporating these insights into its decision-making processes.

Adjusted EBITDA

We define Adjusted EBITDA as net income (loss) available to TRC before interest, income taxes, depreciation and amortization, and other items that we believe should be adjusted consistent with our core operating performance. The adjusting items are detailed in the Adjusted EBITDA reconciliation table and its footnotes. Adjusted EBITDA is used as a supplemental financial measure by us and by external users of our financial statements such as investors, commercial banks and others. The economic substance behind our use of Adjusted EBITDA is to measure the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and pay dividends to our investors.

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

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

Distributable Cash Flow

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

Distributable cash flow is a significant performance metric used by us and by external users of our financial statements, such as investors, commercial banks and research analysts, to compare basic cash flows generated by us (prior to the establishment of any retained cash reserves by our board of directors) to the cash dividends we expect to pay our shareholders. Using this metric, management and external users of our financial statements can quickly compute the coverage ratio of estimated cash flows to cash dividends. Distributable cash flow is also an important financial measure for our shareholders since it serves as an indicator of our success in providing a cash return on investment. Specifically, this financial measure indicates to investors whether or not we are generating cash flow at a level that can sustain or support an increase in our quarterly dividend rates.

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

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

Our Non-GAAP Financial Measures

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

	2017	2016	2015
	(In millions)		
Reconciliation of Net Income (Loss) attributable to TRC to Operating Margin and Gross Margin:			
Net income (loss) attributable to TRC	$ 54.0	$ (187.3)	$ 58.3
Net income (loss) attributable to noncontrolling interests	50.2	28.2	(209.7)
Net income (loss)	104.2	(159.1)	(151.4)
Depreciation and amortization expense	809.5	757.7	644.5
General and administrative expense	203.4	187.2	161.7
Impairment of property, plant and equipment	378.0	—	32.6
Impairment of goodwill	—	207.0	290.0
Interest expense, net	233.7	254.2	231.9
Income tax expense (benefit)	(397.1)	(100.6)	39.6
(Gain) loss on sale or disposition of assets	15.9	6.1	(8.0)
(Gain) loss from financing activities	16.8	48.2	10.1
Other, net	(78.5)	13.6	30.0
Operating margin	1,285.9	1,214.3	1,281.0
Operating expenses	622.9	553.7	540.0
Gross margin	$ 1,908.8	$ 1,768.0	$ 1,821.0

	2017	2016	2015
	(In millions)		
Reconciliation of Net Income (Loss) attributable to TRC to Adjusted EBITDA and Distributable Cash Flow			
Net income (loss) attributable to TRC	$ 54.0	$ (187.3)	$ 58.3
Impact of TRC/TRP Merger on NCI	—	(3.8)	(180.1)
Income attributable to TRP preferred limited partners	11.3	11.3	2.4
Interest expense, net	233.7	254.2	231.9
Income tax expense (benefit)	(397.1)	(100.6)	39.6
Depreciation and amortization expense	809.5	757.7	644.5
Impairment of property, plant and equipment	378.0	—	32.6
Impairment of goodwill	—	207.0	290.0
(Gain) loss on sale or disposition of assets	15.9	6.1	(8.0)
(Gain) loss from financing activities (1)	16.8	48.2	10.1
(Earnings) loss from unconsolidated affiliates	17.0	14.3	2.5
Distributions from unconsolidated affiliates and preferred partner interests, net	18.0	17.5	21.1
Change in contingent consideration included in Other expense	(99.6)	(0.4)	(1.2)
Compensation on equity grants	42.3	29.7	25.0
Transaction costs related to business acquisitions	5.6	—	27.3
Splitter Agreement (2)	43.0	10.8	—
Risk management activities (3)	10.0	25.2	64.8

Other	—	—	0.6
Noncontrolling interests adjustments (4)	(18.6)	(25.0)	(69.7)
TRC Adjusted EBITDA	$ 1,139.8	$ 1,064.9	$ 1,191.7
Distributions to TRP preferred limited partners	(11.3)	(11.3)	(2.4)
Cash received from payments under Splitter Agreement (2)	43.0	43.0	—
Splitter Agreement (2)	(43.0)	(10.8)	—
Interest expense on debt obligations (5)	(224.3)	(263.8)	(253.3)
Cash tax (expense) benefit (6)	46.7	20.9	(15.0)
Maintenance capital expenditures	(100.7)	(85.7)	(97.9)
Noncontrolling interests adjustments of maintenance capex	1.6	5.2	7.2
Distributable Cash Flow	$ 851.8	$ 762.4	$ 830.3

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

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

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

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

(5) Excludes amortization of interest expense.

(6) Includes an adjustment, reflecting the benefit from net operating loss carryback to 2015 and 2014, which was recognized over the periods between the third quarter 2016 recognition of the receivable and the anticipated receipt date of the refund. The refund, previously expected to be received on or before the fourth quarter of 2017, was received in the second quarter of 2017. The year ended December 31, 2017 also includes a refund of Texas margin tax paid in previous periods and received in 2017.

Consolidated Results of Operations

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

	Year Ended December 31, 2017	2016	2015	2017 vs. 2016		2016 vs. 2015	
	(In millions, except operating statistics and price amounts)						
Revenues							
Sales of commodities	$ 7,751.1	$ 5,626.8	$ 5,465.4	$ 2,124.3	38 %	$ 161.4	3 %
Fees from midstream services	1,063.8	1,064.1	1,193.2	(0.3)	—	(129.1)	(11 %)
Total revenues	8,814.9	6,690.9	6,658.6	2,124.0	32 %	32.3	—
Product purchases	6,906.1	4,922.9	4,837.6	1,983.2	40 %	85.3	2 %
Gross margin (1)	1,908.8	1,768.0	1,821.0	140.8	8 %	(53.0)	(3 %)
Operating expenses	622.9	553.7	540.0	69.2	12 %	13.7	3 %
Operating margin (1)	1,285.9	1,214.3	1,281.0	71.6	6 %	(66.7)	(5 %)
Depreciation and amortization expense	809.5	757.7	644.5	51.8	7 %	113.2	18 %
General and administrative expense	203.4	187.2	161.7	16.2	9 %	25.5	16 %
Impairment of property, plant and equipment	378.0	—	32.6	378.0	—	(32.6)	(100%)
Impairment of goodwill	—	207.0	290.0	(207.0)	(100%)	(83.0)	(29 %)
Other operating (income) expense	17.4	6.6	(7.1)	10.8	164 %	13.7	193 %
Income (loss) from operations	(122.4)	55.8	159.3	(178.2)	NM	(103.5)	(65 %)
Interest expense, net	(233.7)	(254.2)	(231.9)	20.5	8 %	(22.3)	(10 %)
Equity earnings (loss)	(17.0)	(14.3)	(2.5)	(2.7)	(19 %)	(11.8)	NM
Gain (loss) from financing activities	(16.8)	(48.2)	(10.1)	31.4	65 %	(38.1)	NM
Change in contingent considerations	99.6	0.4	1.2	99.2	NM	(0.8)	(67 %)
Other income (expense), net	(2.6)	0.8	(27.8)	(3.4)	NM	28.6	103 %
Income tax (expense) benefit	397.1	100.6	(39.6)	296.5	295 %	140.2	NM
Net income (loss)	104.2	(159.1)	(151.4)	263.3	165 %	(7.7)	(5 %)
Less: Net income (loss) attributable to noncontrolling interests	50.2	28.2	(209.7)	22.0	78 %	237.9	113 %
Net income (loss) attributable to Targa Resources Corp.	54.0	(187.3)	58.3	241.3	129 %	(245.6)	NM
Dividends on Series A Preferred Stock	91.7	72.6	—	19.1	26 %	72.6	—
Deemed dividends on Series A Preferred Stock	25.7	18.2	—	7.5	41 %	18.2	—
Net income (loss) attributable to common shareholders	$ (63.4)	$ (278.1)	$ 58.3	$ 214.7	77 %	$ (336.4)	NM
Financial and operating data:							
Financial data:							
Adjusted EBITDA (1)	$ 1,139.8	$ 1,064.9	$ 1,191.7	$ 74.9	7 %	$ (126.8)	(11 %)
Distributable cash flow (1)	851.8	762.4	830.3	89.4	12 %	(67.9)	(8 %)
Capital expenditures	1,506.5	592.1	777.2	914.4	154 %	(185.1)	(24 %)

Business acquisition (2)	987.1	—	5,024.2	987.1	—			(5,024.2	)	(100	%)
Operating statistics: (3)											
Crude oil gathered, Badlands, MBbl/d	113.6	105.2	106.3	8.4	8	%		(1.1	)	(1	%)
Crude oil gathered, Permian, MBbl/d (4)	29.8	—	—	29.8	—			—		—	
Plant natural gas inlet, MMcf/d (5) (6)	3,473.7	3,399.6	3,241.3	74.1	2	%		158.3		5	%
Gross NGL production, MBbl/d	333.2	305.4	265.5	27.8	9	%		39.9		15	%
Export volumes, MBbl/d (7)	184.1	181.4	183.0	2.7	1	%		(1.6	)	(1	%)
Natural gas sales, BBtu/d (6) (8)	2,004.0	1,962.9	1,770.7	41.1	2	%		192.2		11	%
NGL sales, MBbl/d (8)	525.6	526.1	517.0	(0.5	)	—		9.1		2	%
Condensate sales, MBbl/d	11.8	10.1	9.3	1.7	17	%		0.8		9	%

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(1) Gross margin, operating margin, Adjusted EBITDA, and distributable cash flow are non-GAAP financial measures and are discussed under "Management's Discussion and Analysis of Financial Condition and Results of Operations – How We Evaluate Our Operations."
(2) Includes the acquisition date fair value of the potential earn-out payments of $416.3 million that would occur in 2018 and 2019.
(3) These volume statistics are presented with the numerator as the total volume sold during the year and the denominator as the number of calendar days during the year.
(4) Includes operations from the Permian Acquisition for the period effective March 1, 2017. For the volume statistics presented, the numerator is the total volume sold during the period of our ownership while the denominator is the number of calendar days during the year.
(5) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant, other than in Badlands, where it represents total wellhead gathered volume.
(6) Plant natural gas inlet volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.
(7) Export volumes represent the quantity of NGL products delivered to third-party customers at our Galena Park Marine Terminal that are destined for international markets.
(8) Includes the impact of intersegment eliminations.
NM Due to a low denominator, the noted percentage change is disproportionately high and as a result, considered not meaningful.

2017 Compared to 2016

The increase in commodity sales was primarily due to higher commodity prices ($2,124.2 million) and increased petroleum products, natural gas and condensate sales volumes ($100.1 million), partially offset by decreased NGL sales volumes ($13.8 million) and the impact of hedge settlements ($86.2 million). Fee-based and other revenues were flat as a result of lower export fees offset by increases in gas processing and crude gathering fees, which included the impact of our March 2017 Permian Acquisition.

The increase in product purchases was primarily due to the impact of higher commodity prices and increased volumes.

In the third quarter of 2017, we experienced limited impacts to our operations from Hurricane Harvey and our operating margin for the full year 2017 was not significantly impacted. No property insurance or business interruption insurance claims were made as a result of the storm.

The higher operating margin and gross margin in 2017 reflect increased segment results for Gathering and Processing, partially offset by decreased Logistics and Marketing segment results. 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 the impact of the March 2017 Permian Acquisition and the impact of other growth investments, including CBF Train 5 that went into service in the second quarter of 2016 and the Raptor Plant at SouthTX that went into service in the second quarter of 2017. These factors were partially offset by lower planned amortization of the Badlands intangible assets.

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

The impairment of property, plant and equipment in 2017 reflects a third quarter impairment of gas processing facilities and gathering systems associated with our North Texas operations in the Gathering and Processing segment. The impairment was the result of our assessment that forecasted undiscounted future net cash flows from operations, while positive, would not be sufficient to recover the total net book value of the underlying assets.

In conjunction with our required annual goodwill assessments, we recognized impairments of goodwill totaling $207.0 million during 2016 related to goodwill acquired in the mergers with Atlas Energy L.P. and Atlas Pipeline Partners L.P. in 2015 (collectively 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 expense in 2017 was primarily due to the reduction in the carrying value of our ownership interest in the Venice Gathering System in connection with the April 2017 sale. Other operating expense in 2016 was primarily due to the loss on decommissioning two storage wells at our Hattiesburg facility and an acid gas injection well at our Versado facility.

Net interest expense in 2017 decreased as compared with 2016 primarily due to lower average outstanding borrowings and higher capitalized interest during 2017, partially offset by higher non-cash interest expense related to the increase in the estimated redemption value of mandatorily redeemable preferred interests.

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

During 2017, we recorded a loss from financing activities of $16.8 million on the redemption of the outstanding 6 % Senior Notes and the repayment of the outstanding balance on our senior secured term loan, whereas in 2016 we recorded a $48.2 million loss from financing activities that included the tender, open market repurchase and redemption of various series of Partnership Senior Notes.

During 2017, we recorded other income for changes in contingent considerations of $99.6 million resulting primarily from a reduction in the estimated fair value of the Permian Acquisition contingent consideration, which is based on a multiple of gross margin realized during the first two annual periods after the acquisition date. The estimated fair value of the contingent consideration may decrease or increase until the settlement dates, resulting in the recognition of additional other income (expense).

The increase in income tax benefit was primarily due to the Tax Cuts and Jobs Act of 2017 (the “Tax Act”) and the resulting reduction of the federal corporate tax rate from 35% to 21%, which under GAAP results in a recalculation of our ending balance sheet deferred tax balances. The resulting $269.5 million reduction of our net deferred tax liability is included in current period earnings. Further, in 2017, which is subject to pre-Tax Act rates, a higher pre-tax loss resulted in higher income tax benefits.

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

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

2016 Compared to 2015

The increase in commodity sales was primarily due to the favorable impact of the inclusion of two additional months of TPL’s operations during 2016 ($270.1 million), partially offset by lower commodity prices ($53.7 million) and the impact of hedge settlements ($42.5 million). Additionally, fee-based and other revenues decreased primarily due to lower fractionation and export fees, partially offset by the impact of an additional two months of TPL’s fee revenue in 2016 ($40.9 million).

The increase in product purchases was primarily due to the inclusion of two additional months of operations from TPL in 2016 ($137.5 million), partially offset by the impact of the lower commodity prices.

The lower operating margin and gross margin in 2016 reflect decreased segment results for Logistics and Marketing, partially offset by increased Gathering and Processing segment results. Operating expenses increased slightly compared to 2015 due to the inclusion of TPL’s operations for an additional two months in 2016, offset by a continued focused cost reduction effort throughout our operating areas. See “—Results of Operations—By Reportable Segment” for additional information regarding changes in operating margin and gross margin on a segment basis.

The increase in depreciation and amortization expense reflects an additional two months of TPL operations in 2016, growth investments from other system expansions including CBF Train 5, the Buffalo Plant, compressor stations and pipelines, and higher planned amortization of the Badlands intangible assets.

General and administrative expense, which includes TPL operations for an additional two months in 2016, increased primarily due to higher compensation and benefits, partially offset by lower insurance premiums.

We recognized impairments of goodwill totaling $207.0 million during 2016, as compared with the $290.0 million provisional impairment of goodwill recorded during the fourth quarter of 2015. Goodwill impairment recorded in 2016 includes $24.0 million recorded in the first quarter to finalize the 2015 provisional charge, as well as an additional $183.0 million associated with our annual impairment evaluation in the fourth quarter of 2016. These impairment charges relate to goodwill acquired in the Atlas mergers in 2015.

There was no impairment of property, plant and equipment in 2016, whereas in 2015 we recorded a loss of $32.6 million to reflect the impairment of certain gas processing facilities and associated gathering systems due to market conditions and processing spreads in Louisiana.

Other operating (income) expense in 2016 includes the loss on decommissioning two storage wells at our Hattiesburg facility and an acid gas injection well at our Versado facility, whereas in 2015 we reported a net gain on sales of assets.

Net interest expense increased primarily due to lower non-cash interest income related to the mandatorily redeemable preferred interests liability that is revalued quarterly at the estimated redemption value as of the reporting date. The estimated redemption value of the mandatorily redeemable preferred interests decreased in 2016 by a lesser amount than in 2015. Other factors included lower capitalized interest due to decreased capital expenditures in 2016, partially offset by the impact of lower average outstanding borrowings during 2016.

The decrease in equity earnings (loss) was due to lower operating results from GCF and the inclusion of an additional two months of equity losses from the T2 Joint Ventures in 2016.

During 2016, we recorded a $48.2 million loss from financing activities that included the tender of $1,138.3 million of Partnership Senior Notes, the repurchase of $559.2 million of Partnership Senior Notes in open market purchases, and the redemption of $146.2 million of Partnership Senior Notes. In 2015, we incurred a net loss from financing activities of $10.1 million from the partial repayments of the TRC senior secured term loan and the repurchase of Partnership Senior Notes.

Other income (expense) in 2015 was primarily attributable to non-recurring transaction costs related to the Atlas mergers.

The change in income tax (expense) benefit was primarily due to the decrease in income (loss) before income taxes and the impact of the TRC/TRP Merger, which eliminated the noncontrolling interest associated with the third-party TRP common unit holders for most of 2016. Income attributable to noncontrolling interests is not subject to income taxes in our financial statements. Therefore, during most of 2016, we recorded income taxes on the majority of the pre-tax loss generated by TRP due to absence of the large noncontrolling interest in TRP.

Despite similar amounts of net losses in 2016 and 2015, net income (loss) attributable to noncontrolling interests was significantly lower for 2016 due to the February 2016 TRC/TRP Merger, which eliminated the noncontrolling interest associated with the third-party TRP common unit holders for most of 2016. The impact of the TRP non-controlling common interest buy-in was most pronounced during the fourth quarter of both years that included significant losses as a result of our annual goodwill impairment evaluations. The noncontrolling interest bore approximately 89% of the fourth quarter impairment loss in 2015 and 0% in 2016. This reduction was partially offset by the impact of a full year of distributions in 2016 for the TRP's Preferred Units issued in October 2015.

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

Results of Operations—By Reportable Segment

Our operating margins by reportable segment are:

	Gathering and Processing	Logistics and Marketing	Other	Corporate and Eliminations	Consolidated Operating Margin
	(In millions)				
2017	$ 783.8	$ 511.8	$ (9.6)	$ (0.1)	$ 1,285.9
2016	577.1	574.4	62.9	(0.1)	1,214.3
2015	515.1	681.7	84.2	—	1,281.0

Gathering and Processing Segment

	Year Ended December 31,						
	2017	2016	2015	2017 vs. 2016		2016 vs. 2015	
Gross margin	$ 1,145.5	$ 903.6	$ 830.1	$ 241.9	27 %	$ 73.5	9 %
Operating expenses	361.7	326.5	315.0	35.2	11 %	11.5	4 %
Operating margin	$ 783.8	$ 577.1	$ 515.1	$ 206.7	36 %	$ 62.0	12 %
Operating statistics (1):							
Plant natural gas inlet, MMcf/d (2),(3)							
Permian Midland (4)	893.5	747.4	608.0	146.1	20 %	139.4	23 %
Permian Delaware (4)	381.8	321.0	346.2	60.8	19 %	(25.2)	(7 %)
Total Permian	1,275.3	1,068.4	954.2	206.9		114.2	
SouthTX	273.2	216.4	120.0	56.8	26 %	96.4	80 %
North Texas	268.1	317.3	347.6	(49.2)	(16%)	(30.3)	(9 %)
SouthOK	494.0	462.1	401.5	31.9	7 %	60.6	15 %
WestOK	377.7	444.9	471.7	(67.2)	(15%)	(26.8)	(6 %)
Total Central	1,413.0	1,440.7	1,340.8	(27.7)		99.9	
Badlands (5)	56.5	52.1	49.2	4.4	8 %	2.9	6 %
Total Field	2,744.8	2,561.2	2,344.2	183.6		217.0	
Coastal	728.8	838.4	897.0	(109.6)	(13%)	(58.6)	(7 %)
Total	3,473.6	3,399.6	3,241.2	74.0	2 %	158.4	5 %
Gross NGL production, MBbl/d (3)							
Permian Midland (4)	118.3	94.5	70.7	23.8	25 %	23.8	34 %
Permian Delaware (4)	43.1	36.4	40.8	6.7	18 %	(4.4)	(11%)
Total Permian	161.4	130.9	111.5	30.5		19.4	
SouthTX	30.4	23.8	13.8	6.6	28 %	10.0	72 %
North Texas	30.2	35.8	39.6	(5.6)	(16%)	(3.8)	(10%)
SouthOK	42.8	39.4	28.1	3.4	9 %	11.3	40 %
WestOK	21.9	27.1	23.8	(5.2)	(19%)	3.3	14 %
Total Central	125.3	126.1	105.3	(0.8)		20.8	
Badlands	7.9	7.3	6.8	0.6	8 %	0.5	7 %
Total Field	294.6	264.3	223.6	30.3		40.7	
Coastal	38.6	41.2	41.8	(2.6)	(6 %)	(0.6)	(1 %)
Total	333.2	305.5	265.4	27.7	9 %	40.1	15 %
Crude oil gathered, Badlands, MBbl/d	113.6	105.2	106.3	8.4	8 %	(1.1)	(1 %)
Crude oil gathered, Permian, MBbl/d (4)	29.8	—	—	29.8	—	—	—
Natural gas sales, BBtu/d (3)	1,665.4	1,623.6	1,577.9	41.8	3 %	45.7	3 %
NGL sales, MBbl/d	254.8	241.3	208.3	13.5	6 %	33.0	16 %

Condensate sales, MBbl/d	11.8	9.9	9.1	1.9	19 %	0.8	9 %
Average realized prices (6):							
Natural gas, $/MMBtu	2.65	2.14	2.38	0.51	24 %	(0.24)	(10%)
NGL, $/gal	0.55	0.36	0.35	0.19	53 %	0.01	3 %
Condensate, $/Bbl	45.52	36.20	41.86	9.32	26 %	(5.66)	(14%)

(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) Includes operations from the Permian Acquisition for the period effective March 1, 2017. New Midland volumes are included within Permian Midland and New Delaware volumes are included within Permian Delaware. For the volume statistics presented, the numerator is the total volume sold during the period of our ownership while the denominator is the number of calendar days during the year.

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

(6) Average realized prices exclude the impact of hedging activities presented in Other.

2017 Compared to 2016

The increase in gross margin was primarily due to higher commodity prices and higher Permian volumes including those associated with the Permian Acquisition. The overall increase in Gathering and Processing inlet volumes included all areas in the Permian region, at SouthTX and SouthOK, partially offset by decreases at WestOK, North Texas and Coastal. The Coastal Gathering and Processing assets generate significantly lower unit margins than the Field Gathering and Processing assets. NGL production, NGL sales and natural gas sales increased primarily due to higher Field Gathering and Processing inlet volumes and increased plant recoveries including additional ethane recovery. Total crude oil gathered volumes increased in the Permian region due to the Permian Acquisition. In the Badlands, total crude oil gathered volumes and natural gas volumes increased primarily due to higher production from new wells and system expansions.

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

2016 Compared to 2015

The increase in gross margin was primarily due to the inclusion of the TPL volumes for all of 2016 and an increase in NGL prices partially offset by lower natural gas and condensate prices and lower inlet volumes in WestOK and on certain of our other systems. The plant inlet volume increase in SAOU was more than offset by reduced producer activity and volumes at Sand Hills (which also had operational issues), Versado and North Texas. Badlands natural gas volumes increased due to system expansions while crude oil volumes were essentially flat. Coastal plant inlet volumes decreased due to current market conditions and the decline of off-system volumes partially offset by additional higher GPM volumes.

Excluding the impact of including operating expenses for TPL for an additional two months in 2016 and system expansions, operating expenses for most areas were lower due to a continued focused cost reduction effort.

Gross Operating Statistics Compared to Actual Reported

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

Operating statistics:	Year Ended December 31, 2017			
Plant natural gas inlet, MMcf/d (1),(2)	Gross Volume (3)	Ownership %	Net Volume (3)	Actual Reported
Permian Midland (4)	1,110.8	Varies (5)	893.5	893.5
Permian Delaware (4)	381.8	100 %	381.8	381.8
Total Permian	1,492.6		1,275.3	1,275.3
SouthTX	273.2	Varies (6) (7)	213.5	273.2
North Texas	268.1	100 %	268.1	268.1
SouthOK	494.0	Varies (8)	397.9	494.0
WestOK	377.7	100 %	377.7	377.7

Total Central	1,413.0			1,257.2	1,413.0
Badlands (9)	56.5	100	%	56.5	56.5
Total Field	2,962.1			2,589.0	2,744.8
Gross NGL production, MBbl/d (2)					
Permian Midland (4)	148.2	Varies (5)		118.3	118.3
Permian Delaware (4)	43.1	100	%	43.1	43.1
Total Permian	191.3			161.4	161.4
SouthTX	30.4	Varies (6) (7)		23.4	30.4
North Texas	30.2	100	%	30.2	30.2
SouthOK	42.8	Varies (8)		34.9	42.8
WestOK	21.9	100	%	21.9	21.9
Total Central	125.3			110.4	125.3
Badlands	7.9	100	%	7.9	7.9
Total Field	324.5			279.7	294.6

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

(3) For these volume statistics presented, the numerator is the total volume sold during the year and the denominator is the number of calendar days during the year.
(4) Includes operations from the Permian Acquisition for the period effective March 1, 2017. New Midland volumes are included within Permian Midland and New Delaware volumes are included within Permian Delaware.
(5) Permian Midland includes operations in WestTX, of which we own 73%, and other plants which are owned 100% by us. Operating results for the WestTX undivided interest assets are presented on a pro-rata net basis in our reported financials.
(6) SouthTX includes the Silver Oak II Plant, of which we owned a 90% interest from October 2015 through May 2017, and after which we own a 100% interest. Silver Oak II is owned by a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials.
(7) SouthTX also includes the Raptor Plant, which began operations in the second quarter of 2017, of which we own a 50% interest through the Carnero Processing Joint Venture. The Carnero Processing Joint Venture is a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials.
(8) SouthOK includes the Centrahoma Joint Venture, of which we own 60%, and other plants which are owned 100% by us. Centrahoma is a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials.
(9) Badlands natural gas inlet represents the total wellhead gathered volume.

	Year Ended December 31, 2016			
Operating statistics:				
Plant natural gas inlet, MMcf/d (1),(2)	Gross Volume (3)	Ownership %	Net Volume (3)	Actual Reported
Permian Midland (4)	929.8	Varies (5)	747.4	747.4
Permian Delaware	321.0	Varies (6)	253.8	321.0
Total Permian	1,250.8		1,001.2	1,068.4
SouthTX	216.4	Varies (7)	205.6	216.4
North Texas	317.3	100 %	317.3	317.3
SouthOK	462.1	Varies (8)	382.0	462.1
WestOK	444.9	100 %	444.9	444.9
Total Central	1,440.7		1,349.8	1,440.7
Badlands (9)	52.1	100 %	52.1	52.1
Total Field	2,743.6		2,403.1	2,561.2
Gross NGL production, MBbl/d (2)				
Permian Midland (4)	117.9	Varies (5)	94.5	94.5
Permian Delaware	36.4	Varies (6)	36.4	36.4
Total Permian	154.3		130.9	130.9
SouthTX	23.8	Varies (7)	22.8	23.8
North Texas	35.8	100 %	35.8	35.8
SouthOK	39.4	Varies (8)	32.6	39.4
WestOK	27.1	100 %	27.1	27.1
Total Central	126.1		118.3	126.1
Badlands	7.3	100 %	7.3	7.3
Total Field	287.7		256.5	264.3

(1) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.
(2) Plant natural gas inlet volumes and gross NGL production volumes include producer take-in-kind volumes.
(3) For these volume statistics presented, the numerator is the total volume sold during the year and the denominator is the number of calendar days during the year.
(4) Includes the Buffalo Plant that commenced commercial operations in April 2016.
(5) Permian Midland includes operations in WestTX, of which we own 73%, and other plants which are owned 100% by us. Operating results for the WestTX undivided interest assets are presented on a pro-rata net basis in our reported financials.
(6) Permian Delaware includes Versado, which is a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials, and other plants which are owned 100% by us. We held a 63% interest in Versado until October 31, 2016, when we acquired the remaining 37% interest.
(7) SouthTX includes the Silver Oak II Plant, of which we owned a 90% interest from October 2015 through May 2017, and after which we own a 100% interest. Silver Oak II is owned by a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials.
(8) SouthOK includes the Centrahoma Joint Venture, of which we own 60%, and other plants which are owned 100% by us. Centrahoma is a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials.
(9) Badlands natural gas inlet represents the total wellhead gathered volume.

	Year Ended December 31, 2015					
Operating statistics:						
Plant natural gas inlet, MMcf/d (1),(2)	Gross Volume (3)	Ownership %	Net Volume (3)	Pro Forma (4)	Timing Adjustment (5)	Actual Reported
SAOU	234.0	100 %	234.0	234.0	—	234.0
WestTX (6)(7)	612.8	73 %	446.1	446.1	(72.1)	374.0
Sand Hills	163.0	100 %	163.0	163.0	—	163.0
Versado (8)	183.2	63 %	115.4	183.2	—	183.2
SouthTX (6)	143.1	100 %	143.1	143.1	(23.1)	120.0
North Texas	347.6	100 %	347.6	347.6	—	347.6
SouthOK (6)	478.9	Varies (9)	398.6	478.9	(77.4)	401.5
WestOK (6)	562.6	100 %	562.6	562.6	(90.9)	471.7
Badlands (10)	49.2	100 %	49.2	49.2	—	49.2
Total Field	2,774.4		2,459.6	2,607.7	(263.5)	2,344.2
Gross NGL production, MBbl/d (2)						
SAOU	27.3	100 %	27.3	27.3	—	27.3
WestTX (6)(7)	71.1	73 %	51.8	51.8	(8.4)	43.4
Sand Hills	17.4	100 %	17.4	17.4	—	17.4
Versado	23.4	63 %	14.7	23.4	—	23.4
SouthTX (6)	16.5	100 %	16.5	16.5	(2.7)	13.8
North Texas	39.6	100 %	39.6	39.6	—	39.6
SouthOK (6)	33.5	Varies (9)	29.1	33.5	(5.4)	28.1
WestOK (6)	28.4	100 %	28.4	28.4	(4.6)	23.8
Badlands	6.8	100 %	6.8	6.8	—	6.8
Total Field	264.0		231.6	244.7	(21.1)	223.6

(1) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.
(2) Plant natural gas inlet volumes and gross NGL production volumes include producer take-in-kind volumes.
(3) For these volume statistics presented, the numerator is the total volume sold during the year and the denominator is the number of calendar days during the year, other than for the volumes related to the APL merger, for which the denominator is 306 days.
(4) Pro forma statistics represents volumes per day while owned by us.
(5) Timing adjustment made to the pro forma statistics to adjust for the actual reported statistics based on the full period.
(6) Operations acquired as part of the APL merger effective February 27, 2015.
(7) Operating results for the WestTX undivided interest assets are presented on a pro-rata net basis in our reported financials.
(8) Versado is a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials. We held a 63% interest in Versado until October 31, 2016, when we acquired the remaining 37% interest.
(9) SouthOK includes the Centrahoma joint venture, of which TPL owns 60%, and other plants which are owned 100% by TPL. Centrahoma is a consolidated subsidiary and its financial results are presented on a gross basis in our reported financials.

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

Logistics and Marketing Segment

	Year Ended December 31,						
	2017	2016	2015	2017 vs. 2016		2016 vs. 2015	
	(In millions)						
Gross margin	$ 773.4	$ 801.8	$ 907.5	$ (28.4)	(4 %)	$ (105.7)	(12%)
Operating expenses	261.6	227.4	225.8	34.2	15 %	1.6	1 %
Operating margin	$ 511.8	$ 574.4	$ 681.7	$ (62.6)	(11%)	$ (107.3)	(16%)
Operating statistics MBbl/d (1):							
Fractionation volumes (2)(3)	354.2	309.3	342.7	44.9	15 %	(33.4)	(10%)
LSNG treating volumes (2)	32.2	24.9	22.4	7.3	29 %	2.5	11 %
Benzene treating volumes (2)	21.6	22.1	22.4	(0.5)	(2 %)	(0.3)	(1 %)
Export volumes, MBbl/d (4)	184.1	181.4	183.0	2.7	1 %	(1.6)	(1 %)
NGL sales, MBbl/d	490.0	477.5	422.1	12.5	3 %	55.4	13 %
Average realized prices:							
NGL realized price, $/gal	$ 0.69	$ 0.49	$0.46	$ 0.20	41 %	$ 0.03	7 %

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(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 and treating contracts include pricing terms composed of base fees and fuel and power components which vary with the cost of energy. As such, the Logistics and Marketing segment results include effects of variable energy costs that impact both gross margin and operating expenses.

(3) Fractionation volumes reflect those volumes delivered and settled under fractionation contracts.

(4) Export volumes represent the quantity of NGL products delivered to third-party customers at our Galena Park Marine Terminal that are destined for international markets.

2017 Compared to 2016

Logistics and Marketing gross margin decreased due to lower LPG export margin and lower domestic marketing margin, partially offset by higher fractionation margin, higher terminaling and storage throughput and higher marketing gains. LPG export margin decreased due to lower fees partially offset by higher volumes. Domestic marketing margin decreased due to lower terminal margins. Fractionation margin increased due to higher supply volume and higher system product gains. Fractionation margin was partially impacted by the variable effects of fuel and power costs that are largely reflected in operating expenses (see footnote (2) above).

Operating expenses increased due to higher fuel and power costs that are largely passed through, higher compensation and benefits related to the operations of CBF Train 5, 2017 repairs and maintenance activities that were not required in 2016 and higher taxes.

2016 Compared to 2015

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

Operating expenses were relatively flat. Higher compensation and benefits and higher ad valorem taxes associated with the start-up of CBF Train 5 were largely offset by lower fuel and power costs, and lower maintenance expense resulting from continued focused cost reductions.

Other

	Year Ended December 31,				
				2017 vs.	2016 vs.
	2017	2016	2015	2016	2015
	(In millions)				
Gross margin	$(9.6)	$62.9	$84.2	$(72.5)	$(21.3)
Operating margin	$(9.6)	$62.9	$84.2	$(72.5)	$(21.3)

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

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

	2017			2016			2015		
	(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)	61.1	$ 0.22	$ 13.5	44.7	$ 0.79	$ 35.2	34.2	$ 1.08	$ 37.0
NGL (MMgal)	262.9	(0.10)	(26.0)	31.9	0.21	6.8	28.4	0.77	22.0
Crude oil (MBbl)	1.3	4.09	5.3	1.1	17.14	19.5	0.9	31.81	29.3
Non-hedge accounting (2)			(2.2)			2.3			(5.0)
Ineffectiveness (3)			(0.2)			(0.9)			0.9
			$ (9.6)			$ 62.9			$ 84.2

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

As part of the Atlas mergers, outstanding TPL derivative contracts with a fair value of $102.1 million as of the acquisition date were novated to us and included in the acquisition date fair value of assets acquired. We received derivative settlements of $7.6 million, $26.6 million, and $67.9 million for the years ended December 31, 2017, 2016 and 2015, related to these novated contracts. The final settlement was received in December 2017. These settlements were reflected as a reduction of the acquisition date fair value of the TPL derivative assets acquired and had no effect on results of operations.

Our Liquidity and Capital Resources

As of December 31, 2017, we had $137.2 million of "Cash and cash equivalents," on our Consolidated Balance Sheet. We believe our cash position, remaining borrowing capacity on our credit facilities (discussed below in "Short-term Liquidity"), and our cash flows from operating activities are adequate to allow us to manage our day-to-day cash requirements and anticipated obligations as discussed further below.

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

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

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

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

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

Short-term Liquidity

Our short-term liquidity on a consolidated basis as of February 9, 2018, was:

	February 9, 2018 (In millions)		
			Consolidated
	TRC	TRP	Total
Cash on hand	$32.9	$316.2	$ 349.1
Total availability under the TRC Revolver	670.0	—	670.0
Total availability under the TRP Revolver	—	1,600.0	1,600.0
Total availability under the Securitization Facility	—	350.0	350.0
	702.9	2,266.2	2,969.1
Less: Outstanding borrowings under the TRC Revolver	(395.0)	—	(395.0)
Outstanding borrowings under the TRP Revolver	—	(320.0)	(320.0)
Outstanding borrowings under the Securitization Facility	—	(350.0)	(350.0)
Outstanding letters of credit under the TRP Revolver	—	(28.9)	(28.9)
Total liquidity	$307.9	$1,567.3	$ 1,875.2

Other potential capital resources associated with our existing arrangements include:

- Our right to request an additional $200 million in commitment increases under the TRC Revolver, subject to the terms therein. The TRC Revolver matures on February 27, 2020.
- Our right to request an additional $500 million in commitment increases under the TRP Revolver, subject to the terms therein. The TRP Revolver matures on October 7, 2020.

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: (1) our cash position; (2) liquids inventory levels and valuation, which we closely manage; (3) changes in the fair value of the current portion of derivative contracts; (4) monthly swings in borrowings under the Securitization Facility; and (5) major structural changes in our asset base or business operations, such as acquisitions or divestitures and certain organic growth projects.

Our working capital, exclusive of current debt obligations, decreased $110.9 million. The major item contributing to this decrease was an increase in capital accruals related to Permian growth projects. The remaining working capital decrease reflects the collection of an income tax refund, partially offset by higher inventories due to price and volume increases, a higher cash balance and an increase in broker margin deposits associated with futures contracts utilized in our derivatives program. The increase of $75.0 million in current debt obligations was due to increased receivables available for the Securitization Facility.

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

Long-term Financing

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

During 2017, under the December 2016 equity distribution agreement, we issued and sold through our sales agents 6,433,561 shares of common stock and received net proceeds of $343.1 million. As of February 9, 2018, we have $266.0 million remaining under our December 2016 equity distribution agreement and the full $750.0 million remaining under our May 2017 equity distribution agreement.

During 2016, 19,983,843 Warrants were exercised and net settled for 11,336,856 shares of common stock. During 2017, no detachable Warrants were exercised. As a result, Series A Warrants exercisable into a maximum of 67,392 shares of common stock and Series B Warrants exercisable into a maximum of 32,496 shares of common stock were outstanding as of December 31, 2017. In February 2018, the remaining 99,888 Warrants were exercised and net settled by us for 58,814 shares of common stock.

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, 2017 and December 31, 2016, the aggregate principal amount outstanding of our various long-term debt obligations (excluding current maturities) was $4,732.6 million and $4,641.8 million, respectively. In October 2017, the Partnership issued $750.0 million aggregate principal amount of 5% Senior Notes due 2028, with net proceeds of $744.1 million after costs, and redeemed its outstanding 5% Senior Notes due 2018 at face value plus accrued interest through the redemption date.

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

The majority of our consolidated long-term debt is fixed rate borrowings; however, we have some exposure to the risk of changes in interest rates, primarily as a result of the variable rate borrowings under the TRC Revolver and the TRP Revolver. We may enter into interest rate hedges with the intent to mitigate the impact of changes in interest rates on cash flows. As of December 31, 2017, we do not have any interest rate hedges.

To date, our and our subsidiaries' debt balances have not adversely affected our operations, ability to grow or ability to repay or refinance indebtedness. For additional information about our debt-related transactions, see Note 10 - Debt

Obligations to our consolidated financial statements. For information about our interest rate risk, see Item 7A "Quantitative and Qualitative Disclosures About Market Risk—Interest Rate Risk."

On February 6, 2018, we announced the formation of the DevCo JVs with Stonepeak. Stonepeak committed a maximum of approximately $960 million of capital to the DevCo JVs, including an initial contribution of approximately $190 million that will be distributed to the Partnership to reimburse it for a portion of capital spent to date. The proceeds from Stonepeak's initial contribution will be used to reduce our current debt.

Compliance with Debt Covenants

As of December 31, 2017, both we and the Partnership were in compliance with the covenants contained in our various debt agreements.

Cash Flow

Cash Flows from Operating Activities

2017	2016	2015	2017 vs. 2016	2016 vs. 2015
(In millions)				
$939.5	$837.4	$1,034.7	$102.1	$(197.3)

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, and (iii) the payment of other expenses, primarily field operating costs, general and administrative expense and interest expense. In addition, we use derivative instruments to manage our exposure to commodity price risk. Changes in the prices of the commodities we hedge impact our derivative settlements as well as our margin deposit requirements on unsettled futures contracts.

Net cash provided by operating activities increased in 2017 compared to 2016, primarily driven by higher commodity prices and a lower average debt balance, offset by the impact of expanded operations in 2017. Higher commodity prices resulted in higher net cash collections from the sale of commodities, partially offset by an increase in NGL product inventory, and higher margin calls and payments related to our derivative contracts. The lower average debt balance in 2017 resulting from the debt repayments in the fourth quarter of 2016 contributed to lower interest charges. In addition, we received net tax refunds mainly from net operating loss carry back. Expanded operations in 2017 contributed to increases in payments for compensation and benefits, as well as utilities.

Net cash provided by operating activities decreased in 2016 compared to 2015, primarily driven by lower commodity prices, the impact of expanded operations, and a higher average debt balance. Lower commodity prices resulted in decreased cash collections from the sale of commodities. Derivative settlements remained an overall source of revenue during 2016, but at a lower amount as commodity price spreads on those derivative contracts were lower in 2016 in comparison to 2015. Expanded operations primarily from the Atlas mergers contributed to increased compensation and benefits, as well as utilities. The higher average debt balance in 2016 that resulted from new debt instruments entered into in 2015 caused increases in interest charges.

Cash Flows from Investing Activities

2017	2016	2015	2017 vs. 2016	2016 vs. 2015
(In millions)				
$(1,892.7)	$(558.6)	$(2,399.6)	$(1,334.1)	$1,841.0

Cash used in investing activities increased in 2017 compared to 2016, primarily due to an $735.4 million increase in capital expenditures, reflecting the spending for major growth projects during 2017 and the acquisition of the Flag City Plant. In addition, outlays for business acquisitions increased by $570.8 million for the cash portion of the Permian Acquisition consideration.

Cash used in investing activities decreased in 2016 compared to 2015, primarily due to the $1,574.4 million outlay for the cash portion of the Atlas merger consideration in 2015. In addition, capital expenditures decreased $255.1 million during 2016 reflecting the completion of major growth projects and cost control initiatives.

Cash Flows from Financing Activities

	2017	2016	2015
Source of Financing Activities, net	(In millions)		
Equity offerings, net of financing costs	$1,644.4	$1,522.6	$766.6
Dividends and distributions	(854.5)	(716.5)	(682.2)
Debt, including financing costs	149.4	(1,127.4)	$1,283.4
Other	77.6	(24.2)	56.3
Net cash provided by (used in) financing activities	$1,016.9	$(345.5)	$1,424.1

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

We incurred a net use of cash from financing activities in 2016, primarily due to a net reduction of outstanding debt and payment of dividends and distributions, partially offset by proceeds from our Series A Preferred issuance and common stock issued under our May 2015 and December 2016 EDAs. With the proceeds from equity issuances we repurchased a portion of the Partnership's senior notes through open market repurchases generally at a discount to par values and repaid a portion of our senior secured credit facilities. With the proceeds from new senior note borrowings and additional borrowings under the TRP Revolver, we tendered for, and then redeemed, certain of the Partnership's senior notes to refinance to longer maturities.

We realized a net source of cash from financing activities in 2015, primarily due to the cash borrowings and equity offerings associated with the Atlas mergers, offset by dividends and distributions. Net borrowings under the Partnership's debt facilities increased, offset by payment to tender APL's senior notes; issuance of our term loan and borrowings under our senior secured credit facility and proceeds from common stock offerings, offset by partial repayments of our term loan and our senior secured credit facility.

Common Dividends

The following table details the dividends on common stock declared and/or paid by us for 2017:

Three Months Ended	Date Paid or To Be Paid	Total Common Dividends Declared	Amount of Common Dividends Paid or To Be Paid	Accrued Dividends (1)	Dividends Declared per Share of Common Stock
(In millions, except per share amounts)					
December 31, 2017	February 15, 2018	$ 202.4	$ 199.1	$ 3.3	$ 0.91000
September 30, 2017	November 15, 2017	199.0	196.2	2.8	0.91000
June 30, 2017	August 15, 2017	198.6	196.2	2.4	0.91000
March 31, 2017	May 16, 2017	182.8	180.3	2.5	0.91000

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

Preferred Dividends

Our Series A Preferred has a liquidation value of $1,000 per share and bears a cumulative 9.5% fixed dividend payable quarterly 45 days after the end of each fiscal quarter. We had the option, but did not elect, to pay dividends in kind ("PIK") for any quarter through December 31, 2017.

Cash dividends of $91.7 million were paid to holders of the Series A Preferred during the year ended December 31, 2017. As of December 31, 2017, cash dividends accrued for our Series A Preferred were $22.9 million, which were paid on February 14, 2018.

Capital Requirements

Our capital requirements relate to capital expenditures, which are classified as growth capital expenditures, business acquisitions, and maintenance expenditures. Growth capital expenditures improve the service capability of the existing assets, extend asset useful lives, increase capacities from existing levels, add capabilities, reduce costs or enhance revenues, and fund acquisitions of businesses or assets. Maintenance capital expenditures are those expenditures that are necessary to maintain the service capability of our existing assets, including the replacement of system components and equipment, which are worn, obsolete or completing their useful life and expenditures to remain in compliance with environmental laws and regulations.

	2017	2016	2015
	(In millions)		
Capital requirements:			
Consideration for business acquisitions	$987.1	$—	$5,024.2
Less: Non-cash value of acquisition (1)	—	—	(3,449.8)
Contingent consideration (2)	(416.3)	—	—
Cash outlay for business acquisition, net of cash acquired	570.8	—	1,574.4
Growth	1,405.7	506.4	679.3
Maintenance	100.8	85.7	97.9
Gross capital expenditures	1,506.5	592.1	777.2
Transfers from materials and supplies inventory to property, plant and equipment	(3.6)	(2.4)	(3.8)
Change in capital project payables and accruals	(205.4)	(27.6)	43.8
Cash outlays for capital projects	1,297.5	562.1	817.2
Total capital outlays	$1,868.3	$562.1	$2,391.6

(1) Includes the fair value of non-cash consideration. See Note 4 – Acquisitions and Divestitures of the “Consolidated Financial Statements”.
(2) See Note 4 – Acquisitions and Divestitures of the “Consolidated Financial Statements.” Represents the fair value of contingent consideration at the acquisition date.

We currently estimate that we will invest at least $1,630 million in net growth capital expenditures (exclusive of outlays for business acquisitions) in 2018. Given our objective of growth through expansions of existing assets, other internal growth projects, and acquisitions, we anticipate that over time that we will invest significant amounts of capital to grow and acquire assets. Future growth capital expenditures may vary significantly based on investment opportunities. We expect that 2018 net maintenance capital expenditures will be approximately $120 million.

Our growth capital expenditures increased for the year ended December 31, 2017 as compared to the year ended December 31, 2016, primarily due to spending related to additional processing plants and associated infrastructure in the Permian Basin, Grand Prix and the Channelview Splitter, as well as the acquisition of the Flag City Plant. The increase was partially offset by the impact of the substantial completion of the CBF Train 5 project in the second quarter of 2016. Our maintenance capital expenditures increased for 2017 as compared to 2016, primarily due to increases in overhauls driven by higher volumes on our systems and additional infrastructure upgrades of the existing capital assets.

Our growth capital expenditures decreased in 2016 as compared to 2015, primarily due to reduced gathering and processing business unit spending activity and lower CBF Train 5 construction costs in 2016. Reductions were partially offset by spending on the Carnero joint ventures and the Channelview Splitter. Our maintenance capital expenditures decreased for 2016 as compared to 2015, primarily due to fewer well connects and lengthened maintenance cycle times resulting from decreases in producer activity, as well as a higher percentage of environmental expenditures incurred in 2015 versus 2016.

Off-Balance Sheet Arrangements

As of December 31, 2017, there were $44.0 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:

Contractual Obligations	Payments Due By Period Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
	(in millions)				
Long-term debt obligations (1)	$ 4,732.6	$ —	$ 1,204.4	$ 6.5	$ 3,521.7
Interest on debt obligations (2)	1,572.2	266.8	464.0	402.8	438.6
Operating leases (3)	42.5	12.6	15.4	14.5	—
Land site lease and rights of way (4)	14.6	3.2	5.8	5.6	—
Purchase Obligations (5):					
Pipeline capacity and throughput agreements (6)	398.1	86.0	137.9	119.0	55.2
Commodities (7)	26.9	26.9	—	—	—
Purchase commitments and service contracts (8)	1,029.6	1,024.1	4.6	0.6	0.3
Other long-term liabilities (9)	58.5	—	18.0	7.5	33.0
	$ 7,875.0	$ 1,419.6	$ 1,850.1	$ 556.5	$ 4,048.8
Commodity Volumetric Commitments					
Natural gas (MMBtu)	5.8	5.8	—	—	—
NGLs (MMgal)	12.0	12.0	—	—	—

(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, 2017 rates for floating debt. See Note 10 - Debt Obligations for more information regarding our debt obligations.
(3) Includes minimum payments on lease obligations for office space, railcars and tractors. See Note 19 - Commitments (Leases) for more information regarding our operating leases.
(4) 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 19 - Commitments (Leases) for more information regarding our land site lease and rights of way.
(5) 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.
(6) Consists of pipeline capacity payments for firm transportation and throughput and deficiency agreements.
(7) Includes natural gas and NGL purchase commitments. Contracts that will be settled at future spot prices are valued using prices as of December 31, 2017.
(8) Includes commitments for capital expenditures, operating expenses and service contracts.
(9)

Includes long-term liabilities of which we are certain of the amount and timing, including certain arrangements that resulted in deferred revenue and other liabilities pertaining to accrued dividends. 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.

Business Acquisitions

For business acquisitions, we generally recognize the identifiable assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at their estimated fair values on the acquisition date. Goodwill results when the cost of a business acquisition exceeds the fair value of the net identifiable assets of the acquired business. Determining fair value requires management's judgment and involves the use of significant estimates and assumptions with respect to projections of future production volumes, pricing and cash flows, benchmark analysis of comparable public companies, discount rates, expectations regarding customer contracts and relationships, and other management estimates. The judgments made in the determination of the estimated fair value assigned to the assets acquired, liabilities assumed and any noncontrolling interest in the investee, the duration of each liability, and any resulting goodwill can materially impact the financial statements in periods after acquisition. See Note 4 – Acquisitions and Divestitures to our consolidated financial statements.

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

In general, depreciation and amortization is the systematic and rational allocation of an asset's cost, less its residual value (if any), to the period it benefits. Our property, plant and equipment are depreciated 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. Amortization expense attributable to intangible assets is recorded in a manner that closely resembles the expected benefit pattern of the intangible assets, or where such pattern is not readily determinable, on a straight-line basis, 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. Examples of such circumstances include:

- changes in energy prices;
- changes in competition;

•changes in laws and regulations that limit the estimated economic life of an asset;

•changes in technology that render an asset obsolete;

•changes in expected salvage values; and

•changes in the forecasted life of applicable resources basins.

Impairment of Long-Lived Assets, including Intangible Assets and Goodwill

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. 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.

As a result of such evaluations, we recorded non-cash pre-tax impairment charges of $378.0 million related to North Texas assets during 2017 and $32.6 million related to certain Coastal gathering and processing assets during 2015. For further details regarding our Property, plant and equipment impairment charges, see Note 6 – Property, Plant and Equipment and Intangible Assets to our consolidated financial statements.

We evaluate goodwill for impairment at least annually, as of November 30, as well as whenever events or changes in circumstances indicate it is more likely than not the fair value of a reporting unit is less than its carrying amount. We early adopted ASU 2017-04 for our annual goodwill impairment test as of November 30, 2017, which requires an impairment up to the amount of goodwill to the extent that the carrying value of the affected reporting unit exceeds its fair value. There was no impairment of goodwill during 2017. Our 2016 and 2015 evaluations were performed under the previous guidance, which required a second step if the carrying value of the reporting unit exceeded its fair value. The second step involved determining the fair value of the assets and liabilities of the affected reporting unit to derive the implied fair value of goodwill. Any excess carrying value over the implied fair value was recognized as a goodwill impairment loss. In 2016 and 2015, we recognized goodwill impairments of $207.0 million and $290.0 million. Included in the 2016 impairment was $24.0 million that represented the finalization of the 2015 provisional impairment.

Our goodwill assessments utilized the income approach (a discounted cash flow analysis (“DCF”)) to estimate the fair values of our reporting units. Future cash flows for our reporting units were based on our estimates, at that time, of future volumes and operating margin and other factors, such as timing of capital expenditures and terminal values. We took into account current and expected industry and market conditions, including commodity pricing, volumetric forecasts and observable exit multiples in the basins in which the reporting units operate. The discount rates used in our DCF analysis were based on a weighted average cost of capital determined from relevant market comparisons. Changes in the forecasts and assumptions used in our DCF analysis could have a material effect on the results of our goodwill assessment.

For further details regarding our Goodwill impairment, see Note 7 – Goodwill to our consolidated financial statements.

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 significant portion of our expected natural gas, NGL, and condensate equity volumes and future commodity purchases and sales.

One of the primary 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. For further details regarding our derivative instruments and fair value measurements, see Note 16 – Derivative Instruments and Hedging Activities and Note 17 – Fair Value Measurements to our consolidated financial statements.

Recent Accounting Pronouncements

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

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

Crude oil, NGL and natural gas prices are also volatile. In an effort to reduce the variability of our cash flows, we have entered into derivative instruments to hedge the commodity price associated with a portion of our expected natural gas equity volumes, NGL equity volumes and condensate equity volumes and future commodity purchases and sales through 2020. Market conditions may also impact our ability to enter into future commodity derivative contracts.

Commodity Price Risk

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

The primary purpose of our commodity risk management activities is to hedge some of the exposure to commodity price risk and reduce fluctuations in our operating cash flow due to fluctuations in commodity prices. In an effort to reduce the variability of our cash flows, as of December 31, 2017, we have hedged the commodity price associated with a portion of our expected (i) natural gas, NGL, and condensate equity volumes in our Gathering and Processing operations that result from our percent-of-proceeds processing arrangements and (ii) future commodity purchases and sales in our Logistics and Marketing segment by entering into derivative instruments. We hedge a higher percentage of our expected equity volumes in the current year compared to future years, for which we hedge incrementally lower percentages of expected equity volumes. With swaps, we typically receive an agreed fixed price for a specified notional quantity of natural gas or NGLs and we pay the hedge counterparty a floating price for that same quantity based upon published index prices. Since we receive from our customers substantially the same floating index price from the sale of the underlying physical commodity, these transactions are designed to effectively lock-in the agreed fixed price in advance for the volumes hedged. In order to avoid having a greater volume hedged than our actual equity volumes, we typically limit our use of swaps to hedge the prices of less than our expected natural gas and NGL equity volumes. We utilize purchased puts (or floors) and calls (or caps) to hedge additional expected equity commodity volumes without creating volumetric risk. We may buy calls in connection with swap positions to create a price floor with upside. We intend to continue to manage our exposure to commodity prices in the future by entering into derivative transactions using swaps, collars, purchased puts (or floors), futures or other derivative instruments as market conditions permit.

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

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

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

During the years ended December 31, 2017, 2016 and 2015, our operating revenues increased (decreased) by $(49.7) million, $40.1 million, and $74.0 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 OCI until the underlying hedged transactions settle. We also enter into derivative instruments to help manage other short-term commodity-related business risks. We have not designated these derivatives as hedges and record changes in fair value and cash settlements to revenues.

Our risk management position has moved from a net liability position of $53.3 million at December 31, 2016 to a net liability position of $38.2 million at December 31, 2017. The fixed prices we currently expect to receive on derivative contracts are below the aggregate forward prices for commodities related to those contracts, creating this net liability position.

As of December 31, 2017, we had the following derivative instruments that will settle during the years shown below:

Natural GAS

Instrument Type	Index	Price $/MMBtu		MMBtu/d 2018	2019	2020	Fair Value (In millions)
Gathering & Processing							
Swap	IF-Waha	2.6470		93,600	-	-	$ 17.4
Swap	IF-Waha	2.6327		-	65,383	-	14.6
				93,600	65,383	-	
Swap	IF-PB	2.4802		45,900	-	-	7.0
Swap	IF-PB	2.3700		-	35,000	-	5.1
				45,900	35,000	-	
Swap	IF-PEPL	2.5960		31,370	-	-	3.3
Swap	IF-PEPL	2.5333		-	31,370	-	2.8
				31,370	31,370	-	
		Put Price	Call Price				
Collar	IF-Waha	3.2500	4.2000	1,849	-	-	0.6
		Put Price	Call Price				
Collar	IF-PB	3.0000	3.6500	7,637	-	-	2.5
Gathering & Processing total				180,356	131,753	-	$ 53.3
Other (1)							
Swap	NG-NYMEX	3.1579		(173)	-	-	$ (0.0)
Swap	NG-NYMEX	2.8367		-	(247)	-	(0.0)
				(173)	(247)	-	
Swap	IF-Waha	3.0589		(4,227)	-	-	(1.0)
Basis Swap	Various	Various		99,521	12,500	10,417	(2.7)
Future	Various	3.2787		466	-	-	0.1
Other total				95,587	12,253	10,417	$ (3.6)
							$ 49.7

(1)

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

NGLs

Instrument Type	Index	Price $/gal		Bbl/d 2018	2019	2020	Fair Value (In millions)
Gathering & Processing							
Swap	C2-OPIS-MB	0.2839		4,688	-	-	$ 0.9
Swap	C2-OPIS-MB	0.2959		-	4,030		(0.9)
Swap	C2-OPIS-MB	0.3005		-		427	(0.1)
Total				4,688	4,030	427	
Swap	C3-OPIS-MB	0.6950		8,620	-	-	(20.3)
Swap	C3-OPIS-MB	0.6060		-	3,780	-	(8.2)
Total				8,620	3,780	-	
Swap	IC4-OPIS-MB	0.8671		1,050	-	-	(1.7)
Swap	IC4-OPIS-MB	0.7814		-	320	-	(0.4)
Total				1,050	320	-	
Swap	NC4-OPIS-MB	0.8608		2,950	-	-	(4.8)
Swap	NC4-OPIS-MB	0.7718		-	900	-	(1.2)
Total				2,950	900	-	
Swap	C5-OPIS-MB	1.1600		1,990	-	-	(6.5)
Swap	C5-OPIS-MB	1.0935		-	859	-	(2.4)
Total				1,990	859	-	
		Put Price	Call Price				
Collar	C3-OPIS-MB	0.530	0.650	900	-	-	(2.9)
		Put Price	Call Price				
Collar	IC4-OPIS-MB	0.650	0.840	110	-	-	(0.3)
Collar	IC4-OPIS-MB	0.640	0.800	-	110	-	(0.3)
Total				110	110	-	
		Put Price	Call Price				
Collar	NC4-OPIS-MB	0.650	0.800	300	-	-	(0.9)
Collar	NC4-OPIS-MB	0.640	0.760	-	300	-	(0.7)
Total				300	300	-	

		Put Price	Call Price				
Collar	C5-OPIS-MB	1.230	1.385	32	-	-	(0.0)
Gathering & Processing total				20,640	10,299	427	$ (50.7)
Other (1)(2)							
Future	C2-OPIS-MB	0.2780		5,192	-	-	$ 0.9
Future	C2-OPIS-MB	0.3138		-	329	-	0.0
Total				5,192	329	-	
Future	C3-OPIS-MB	0.8668		6,592	-	-	(13.3)
Future	IC4-OPIS-MB	0.7825		55	-	-	(0.3)
Future	NC4-OPIS-MB	0.8551		2,110	-	-	(7.2)
Future	C5-OPIS-MB	1.1905		712	-	-	(2.5)
	Put Price						
Option	C2-OPIS-MB	0.2963		1,644	-	-	1.4
Other total				16,305	329	-	$ (21.0)
							$ (71.7)

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(1) Other includes derivative agreements entered into for the purpose of hedging future commodity purchases and sales in our Logistics and Marketing segment.
(2) The "Future" line items are comprised of futures transactions entered into on both the Intercontinental Exchange ("ICE") and Chicago Mercantile Exchange ("CME").

CONDENSATE

Instrument Type	Index	Price $/Bbl		Bbl/d 2018	2019	2020	Fair Value (In millions)
Gathering & Processing							
Swap	WTI-NYMEX	50.91		3,790	-	-	$ (11.5)
Swap	WTI-NYMEX	50.76		-	1,753	-	(3.2)
				3,790	1,753	-	
		Put Price	Call Price				
Collar	WTI-NYMEX	49.76	58.50	691	-	-	(0.9)
Collar	WTI-NYMEX	48.00	56.25	-	590	-	(0.6)
				691	590	-	
Total				4,481	2,343	-	
							$ (16.2)

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

We account for the fair value of our financial assets and liabilities using a three-tier fair value hierarchy, which prioritizes the significant inputs used in measuring fair value. These tiers include: Level 1, defined as observable inputs such as quoted prices in active markets; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions. We determine the value of our derivative contracts utilizing a discounted cash flow model for swaps and a standard option pricing model for options, based on inputs that are readily available in public markets. For the contracts that have inputs from quoted prices, the classification of these instruments is Level 2 within the fair value hierarchy. For those contracts which we are unable to obtain quoted prices for at least 90% of the full term of the commodity contract, the valuations are classified as Level 3 within the fair value hierarchy. See Note 16 - Fair Value Measurements in this Annual Report for more information regarding classifications within the fair value hierarchy.

Interest Rate Risk

We are exposed to the risk of changes in interest rates, primarily as a result of variable rate borrowings under the TRC Revolver, the TRP Revolver and the Securitization Facility. As of December 31, 2017, we do not have any interest rate hedges. However, we may enter into interest rate hedges in the future with the intent to mitigate the impact of changes in interest rates on cash flows. To the extent that interest rates increase, interest expense for the TRC Revolver, the TRP Revolver and the Securitization Facility will also increase. As of December 31, 2017, the Partnership had $370.0 million in outstanding variable rate borrowings under the TRP Revolver and the Securitization Facility, and we had outstanding variable rate borrowings of $435.0 million under the TRC Revolver. A hypothetical change of 100 basis points in the interest rate of our variable rate debt would impact the Partnership’s annual interest expense by $3.7 million and our consolidated annual interest expense by $8.1 million.

Counterparty Credit Risk

We are subject to risk of losses resulting from nonpayment or nonperformance by our counterparties. The credit exposure related to commodity derivative instruments is represented by the fair value of the asset position (i.e. the fair value of expected future receipts) at the reporting date. Our futures contracts have limited credit risk since they are cleared through an exchange and are margined daily. Should the creditworthiness of one or more of the counterparties decline, our ability to mitigate nonperformance risk is limited to a counterparty agreeing to either a voluntary termination and subsequent cash settlement or a novation of the derivative contract to a third party. In the event of a counterparty default, we may sustain a loss and our cash receipts could be negatively impacted. We have master netting provisions in the International Swap Dealers Association agreements with all our derivative counterparties. These netting provisions allow us to net settle asset and liability positions with the same counterparties within the same Targa entity, and would reduce our maximum loss due to counterparty credit risk by $61.1 million as of December 31, 2017. The range of losses attributable to our individual counterparties would be between $0.6 million and $22.0 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, 2017, our operating income would decrease by $8.3 million in the year of the assessment.

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, 2017, 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, 2017.

(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, 2017 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.

Our executive officers listed below serve in the same capacity for the general partner and devote their time as needed to conduct the business and affairs of both the Company and the Partnership. Because the Company’s only cash-generating assets are direct and indirect partnership interests in the Partnership, we expect that our executive officers will devote a substantial majority of their time to the Partnership’s business and affairs. We expect the amount of time that our executive officers devote to the Company’s business and affairs as opposed to the Partnership’s business and affairs in future periods will not be substantial unless significant changes are made to the nature of the Company’s business.

Our 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 of directors. There are no family relationships among any of our directors or executive officers. The following table sets forth certain information with respect to our directors, executive officers and other officers as of February 17, 2018:

Name	Age	Position
Joe Bob Perkins	57	Chief Executive Officer and Director
James W. Whalen	76	Executive Chairman of the Board and Director
Michael A. Heim	69	Vice Chairman of the Board and Director
Jeffrey J. McParland	63	President-Administration
Paul W. Chung	57	Executive Vice President, General Counsel and Secretary
Matthew J. Meloy	40	Executive Vice President and Chief Financial Officer
D. Scott Pryor	55	Executive Vice President – Logistics and Marketing
Patrick J. McDonie	57	Executive Vice President – Southern Field Gathering and Processing
Dan C. Middlebrooks	61	Executive Vice President – Northern Field Gathering and Processing
Clark White	58	Executive Vice President – Engineering and Operations
Robert M. Muraro	41	Executive Vice President – Commercial
John R. Klein	67	Senior Vice President and Chief Accounting Officer
Jennifer R. Kneale	39	Vice President – Finance
Rene R. Joyce	70	Director
Charles R. Crisp	70	Director
Chris Tong	61	Director
Ershel C. Redd Jr.	70	Director
Laura C. Fulton	54	Director
Waters S. Davis, IV	64	Director
Robert B. Evans	69	Director

Joe Bob Perkins has served as Chief Executive Officer and director of the Company and the General Partner since January 1, 2012. Mr. Perkins previously served as President of the Company between the date of its formation on October 27, 2005 and December 31, 2011 and of the General Partner between October 2006 and December 31, 2011. He also served as President of predecessor companies from 2003 through 2005. Mr. Perkins was an independent consultant in the energy industry from 2002 through 2003 and was an active partner in an outdoor advertising firm during a portion of such time period. Mr. Perkins served as President and Chief Operating Officer for the Wholesale Businesses, Wholesale Group and Power Generation Group of Reliant Resources, Inc. and its parent/predecessor companies, from 1998 to 2002 and Vice President, Corporate Planning and Development, of Houston Industries from 1996 to 1998. He served as Vice President, Business Development, of Coral Energy Holding, L.P. (“Coral”) from 1995 to 1996 and as Director, Business Development, of Tejas Gas Corporation (“Tejas”) from 1994 to 1995. Prior to 1994, Mr. Perkins held various positions with the consulting firm of McKinsey & Company and with an exploration and production company. Mr. Perkins’ intimate knowledge of all facets of the Company, derived from his service as President from its founding through 2011 and his current service as Chief Executive Officer and director, coupled with his broad experience in the oil and gas 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 Executive Chairman of the Board of the Company and the General Partner since January 1, 2015. Mr. Whalen has also served as a director of the Company since its formation on October 27, 2005 and of the General Partner since February 2007. 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 the General Partner between January 1, 2012 and December 31, 2014. He served as Executive Chairman of the Board of the Company between October 25, 2010 and December 31, 2011 and of the General Partner between December 15, 2010 and December 31, 2011. He also served as President-Finance and Administration of the Company between January 2006 and October 2010 and the 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 from February 1998 through January 2000. Previously, he served as Chief Financial Officer for 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.

Michael A. Heim has served as a director of the Company since March 1, 2016 and Vice Chairman of the Board since March 11, 2016. He has also served as a director and Vice Chairman of the Board of the General Partner since November 12, 2015. Mr. Heim previously served as President and Chief Operating Officer of the Company and the General Partner between January 1, 2012 and November 12, 2015. Mr. Heim previously served as Executive Vice President and Chief Operating Officer of the Company between the date of its formation on October 27, 2005 and December 2011 and of the General Partner between October 2006 and December 2011. He also served as an officer of an affiliate of the Company during 2004 and 2005 and was a consultant for the affiliate during 2003. Mr. Heim also served as a consultant in the energy industry from 2001 through 2003 providing advice to various energy companies and investors regarding their operations, acquisitions and dispositions. Mr. Heim served as Chief Operating Officer and Executive Vice President of Coastal Field Services, a subsidiary of The Coastal Corp. (“Coastal”) a diversified energy company, from 1997 to 2001 and President of Coastal States Gas Transmission Company from 1997 to 2001. In these positions, he was responsible for Coastal’s midstream gathering, processing, and marketing businesses. Prior to 1997, he served as an officer of several other Coastal exploration and production, marketing and midstream subsidiaries.

Jeffrey J. McParland has served as President – Administration of the Company since February 22, 2017. He previously served as President — Finance and Administration of the Company between October 25, 2010 and February 22, 2017 and of the General Partner between December 15, 2010 and February 22, 2017. He has also served as Executive Vice President and Chief Financial Officer of the Company between October 27, 2005 and October 25, 2010. He also served as an officer of an affiliate of the Company during 2004 and 2005 and was a consultant for the affiliate during 2003. He served as Executive Vice President and Chief Financial Officer of the General Partner between October 2006 and December 15, 2010 and served as a director of the General Partner from October 2006 to February 2007. Mr. McParland served as Treasurer of the Company from October 27, 2005 until May 2007 and of the General Partner from October 2006 until May 2007. Mr. McParland served as Senior Vice President, Finance of Dynegy Inc., a company engaged in power generation, the midstream natural gas business and energy marketing, from 2000 to 2002. In this position, he was responsible for corporate finance and treasury operations activities. He served as Senior Vice President, Chief Financial Officer and Treasurer of PG&E Gas Transmission, a midstream natural gas and regulated natural gas pipeline company, from 1999 to 2000. Prior to 1999, he worked in various engineering and finance positions with companies in the power generation and engineering and construction industries.

Paul W. Chung has served as Executive Vice President, General Counsel and Secretary of the Company since its formation on October 27, 2005 and of the 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.

Matthew J. Meloy has served as Executive Vice President and Chief Financial Officer of the Company and the General Partner since May 2015. Mr. Meloy will serve as President of the Company and the General Partner, effective March 1, 2018. He also served as Treasurer of the Company and the General Partner until December 2015. Mr. Meloy previously served as Senior Vice President, Chief Financial Officer and Treasurer of the Company since October 25, 2010 and of the General Partner since December 15, 2010. 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 the General Partner between March 2006 and March 2008. He has served as Vice President — Finance and Treasurer of the 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, most recently serving as Assistant Vice President.

D. Scott Pryor, has served as Executive Vice President – Logistics and Marketing of the Company and the General Partner since November 12, 2015. Mr. Pryor will serve as President – Logistics and Marketing of the Company and the General Partner, effective March 1, 2018. Mr. Pryor previously 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.

Patrick J. McDonie, has served as Executive Vice President – Southern Field Gathering and Processing of the Company and the General Partner since November 12, 2015. Mr. McDonie will serve as President – Gathering and Processing of the Company and the General Partner, effective March 1, 2018. Mr. McDonie previously served as President of Atlas Pipeline Partners GP LLC (“Atlas”), which was acquired by the Partnership on February 28, 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.

Dan C. Middlebrooks, has served as Executive Vice President – Northern Field Gathering and Processing of the Company and the General Partner since November 12, 2015. Mr. Middlebrooks 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 – Supply and Business Development of various subsidiaries of Targa Operating between June 2010 and May 2014 and has held officer positions with other Partnership subsidiaries since 2008.

Clark White, has served as Executive Vice President – Engineering and Operations of the Company and the General Partner since November 12, 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.

Robert M. Muraro has served as Executive Vice President – Commercial of the Company and the General Partner since February 22, 2017. Mr. Muraro will serve as Chief Commercial Officer of the Company and the General Partner, effective March 1, 2018. previously 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.

John R. Klein has served as Senior Vice President and Chief Accounting Officer of the Company and the General Partner since February 22, 2017. Mr. Klein previously served as Senior Vice President – Controller of the Company and the General Partner between December 2015 and February 2017. He also served as Vice President – Controller of the Company between March 2007 and December 2015 and of the General Partner between November 2007 and December 2015. Mr. Klein served as a senior executive in a consulting firm from 1995 through 2006. Prior to 1995, he held various executive accounting management positions in the energy industry and in public accounting.

Jennifer R. Kneale will serve as Chief Financial Officer of the Company and the General Partner, effective March 1, 2018. Ms. Kneale has served as Vice President - Finance of the Company and the General Partner since December 16, 2015. She previously served as Senior Director, Finance of the Company and the General Partner between March 2015 and December 2015. She also served as Director, Finance of the Company and the 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. Ms. Kneale will replace Mr. Meloy as Chief Financial Officer of the Company on the effective date of her appointment.

Rene R. Joyce has served as a director of the Company since its formation on October 27, 2005 and of the General Partner since October 2006. Mr. Joyce previously served as Executive Chairman of the Board of the General Partner between January 1, 2012 and December 31, 2014. He also served as Chief Executive Officer of the Company between October 27, 2005 and December 31, 2011 and the General Partner between October 2006 and December 31, 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. He also served as a member of the supervisory directors of Core Laboratories N.V. until May 2013. 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 on October 27, 2005 and of the General Partner since March 1, 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 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 IntercontinentalExchange 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 the General Partner since March 1, 2016. Mr. Tong is a director of Kosmos Energy Ltd. 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 and in his position as the chairman of our Audit Committee.

Ershel C. Redd Jr. has served as a director of the Company since February 2011 and of the General Partner since March 1, 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 26, 2013 and of the General Partner since March 1, 2016. Ms. Fulton has served as the Chief Financial Officer of Hi-Crush Proppants LLC since April 2012 and Hi-Crush GP LLC, the general partner of Hi-Crush Partners LP, since May 2012. 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 current position with a 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 the General Partner since March 1, 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 1, 2016 and of the General Partner since February 2007. Mr. Evans is also a director of New Jersey Resources Corporation, Sprague Resources GP LLC and One Gas, Inc. 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.

Board of Directors

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

Our directors are divided into three classes serving staggered three-year terms. Class I, Class II and Class III directors will serve until our annual meetings of stockholders in 2020, 2018 and 2019, respectively. The Class I directors are Messrs. Crisp, Heim and Whalen and Ms. Fulton the Class II directors are Messrs. Evans, Redd, and Perkins and the

Class III directors are Messrs. Tong, Joyce and Davis. At each annual meeting of stockholders, directors will be elected to succeed the class of directors whose terms have expired. This classification of our board of directors could have the effect of increasing the length of time necessary to change the composition of a majority of the board of directors. In general, at least two annual meetings of stockholders will be necessary for stockholders to effect a change in a majority of the members of the board of directors.

Committees of the Board of Directors

Our board of directors has three standing committees – an Audit Committee, a Compensation Committee and a Nominating and Governance Committee - and may have such other committees as the board of directors shall determine from time to time. Each of the standing committees of the board of directors has the composition and responsibilities described below.

Audit Committee

The members of our Audit Committee are Messrs. Tong and Redd and Ms. Fulton. Mr. Tong is the Chairman of this committee. Our board of directors has affirmatively determined that Messrs. Tong and Redd and Ms. Fulton 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, Mr. Tong 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. 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.

Compensation Committee

The members of our Compensation Committee are Messrs. Crisp, Davis and Evans. Mr. Davis is the Chairman of this committee. This committee establishes salaries, incentives and other forms of compensation for officers and other employees. Our Compensation Committee also administers our incentive compensation and benefit plans. We have adopted a Compensation Committee charter defining the committee's primary duties in a manner consistent with the rules of the SEC and NYSE or market standards.

In May 2017, the Compensation Committee considered the independence of BDO USA, LLP ("BDO"), our compensation consultant, in light of new SEC rules and the NYSE listing standards. The Compensation Committee requested and received a letter from BDO addressing the consulting firm's independence, including the following factors:

- Other services provided to us by BDO;
- Fees paid by us as a percentage of BDO total revenue;
- Policies or procedures maintained by BDO that are designed to prevent a conflict of interest;
- Any business or personal relationships between the individual consultants involved in the engagement and members of the Compensation Committee;
- Any stock of the Company owned by the individual consultants involved in the engagement; and
- Any business or personal relationships between our executive officers and BDO or the individual consultants involved in the engagement.

The Compensation Committee discussed these considerations and concluded that the work of BDO did not raise any conflict of interest.

Nominating and Governance Committee

The members of our Nominating and Governance Committee are Messrs. Crisp, Tong and Davis. Mr. Crisp is the Chairman of this committee. This committee identifies, evaluates and recommends qualified nominees to serve on our board of directors, develops and oversees our internal corporate governance processes and maintains a management succession plan. We have adopted a Nominating and Governance Committee charter defining the committee's primary duties in a manner consistent with the rules of the SEC and NYSE or market standards.

In evaluating director candidates, the Nominating and Governance Committee assesses whether a candidate possesses the integrity, judgment, knowledge, experience, skills and expertise that are likely to enhance the board's ability to manage and direct the affairs and business of the Company, including, when applicable, to enhance the ability of committees of the board to fulfill their duties.

Corporate Governance

Code of Business Conduct and Ethics

Our board of directors has adopted a Code of Ethics For Chief Executive Officer and Senior Financial Officers (the "Code of Ethics"), which applies to our Chief Executive Officer, Chief Financial Officer, Chief Accounting Officer, Controller and all of our other senior financial and accounting officers, and our Code of Conduct (the "Code of Conduct"), which applies to our and our subsidiaries' officers, directors and employees. 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 stockholder who so requests, our Corporate Governance Guidelines, Code of Ethics, Code of Conduct, Audit Committee Charter, Compensation Committee charter and Nominating and Governance Committee charter. Requests for print copies may be directed to: Investor Relations, Targa Resources Corp., 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 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 Corp., 811 Louisiana, Suite 2100, Houston, Texas 77002.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires our directors, executive officers and 10% stockholders to file with the SEC reports of ownership and changes in ownership of our equity securities. Based solely upon a review of the copies of the Form 3, 4 and 5 reports furnished to us and certifications from our directors and executive officers, we believe that during 2017, all of our directors, executive officers and beneficial owners of more than 10% of our common units complied with Section 16(a) filing requirements applicable to them.

Item 11. Executive Compensation.

COMPENSATION DISCUSSION AND ANALYSIS

The following Compensation Discussion and Analysis (“CD&A”) contains statements regarding our compensation programs and our executive officers’ business priorities related to our compensation programs and target payouts under the programs. These business priorities are disclosed in the limited context of our compensation programs and should not be understood to be statements of management’s expectations or estimates of results or other guidance.

Overview

Compensatory arrangements with our executive officers identified in the Summary Compensation Table ("named executive officers") are approved by the Compensation Committee of our Board of Directors (the "Compensation Committee"). For 2017, our named executive officers were:

Name	Position During 2017
Joe Bob Perkins	Chief Executive Officer
Matthew J. Meloy	Executive Vice President and Chief Financial Officer
Patrick J. McDonie	Executive Vice President - Southern Field Gathering and Processing
Robert M. Muraro	Executive Vice President - Commercial
D. Scott Pryor	Executive Vice President - Logistics and Marketing

We saw a change in the composition of our named executive officers from the 2016 and 2017 years largely due to certain retention awards that were granted in 2017, as described further below. As announced by the Company on February 1, 2018, four of our named executive officers have been promoted to new positions effective March 1, 2018 as follows: Mr. Meloy as President; Mr. McDonie as President – Gathering and Processing; Mr. Pryor as President – Logistics and Marketing; and Mr. Muraro as Chief Commercial Officer. At the same time, Jennifer R. Kneale was appointed Chief Financial Officer effective March 1, 2018.

Our operating assets are held by subsidiaries of the Partnership, and our named executive officers also served as executive officers of its General Partner during 2017. The named executive officers devote their time as needed to the conduct of our business and affairs and the conduct of the Partnership's business and affairs. The Company acquired all of the Partnership common units not already owned by it pursuant to a merger transaction (the "Buy-In Transaction") effective as of February 17, 2016. Following completion of the Buy-In Transaction, the Partnership's common units ceased to be publicly traded.

The compensation information described in this CD&A and contained in the tables that follow reflects all compensation received by our named executive officers for the services they provide to us and for the services they provide to the General Partner and the Partnership for the years indicated. For 2017, the Compensation Committee was generally responsible for determining and setting compensation practices for our named executive officers. During 2017, the Partnership reimbursed us and our affiliates for the compensation of our named executive officers pursuant to the Partnership's partnership agreement. See "Transactions with Related Persons—Reimbursement of Operating and General and Administrative Expense" in "Item 13 – Certain Relationships and Related Transactions, and Director Independence" for additional information regarding the Partnership's reimbursement obligations.

The Compensation Committee believes that it has taken actions to govern compensation in a responsible way, as described in this CD&A, and that the Company's performance over its trading history demonstrates that our compensation programs are structured to pay reasonable amounts for performance based on our understanding of the markets in which we compete for executive talent and the returns our shareholders have realized.

We held our most recent advisory say-on-pay vote regarding executive compensation at our 2017 Annual Meeting. At that meeting, more than 97% of the votes cast by our shareholders approved, on an advisory basis, of the compensation paid to our named executive officers as described in the CD&A and the other related compensation tables and disclosures contained in our Proxy Statement filed with the SEC on March 29, 2017. The Board of Directors and the Compensation Committee reviewed the results of this vote and concluded that, with this level of support, no changes to our compensation design and philosophy needed to be considered as a result of the say-on-pay vote. In accordance with the preference expressed by our shareholders to conduct an advisory vote on executive compensation every year, the next advisory vote will occur this year at the 2018 Annual Meeting.

Summary of Key Strategic Results

As noted above, our operating assets are held in the Partnership. As described in "Management's Discussion and Analysis of Financial Conditions and Results of Operations" in our Annual Report on Form 10-K for the year ended December 31, 2017, our 2017 strategic and operational accomplishments and our 2017 financial results (including the financial results of the Partnership on a consolidated basis) demonstrate the performance of our businesses through the industry downturn, which, along with our ongoing growth capital expenditure programs, have allowed us to increase both our business scale and diversity. In summary, certain of our more significant financial, operational and strategic highlights in 2017 included:

Excellent execution across our businesses with Company Adjusted EBITDA of $1.14 billion, driven by higher Field G&P volumes, higher fractionation volumes, and continued strong export volumes while exceeding public EBITDA guidance, and with dividend coverage that achieved public guidance;

Excellent execution on 2017 growth capital expenditures of approximately $2 billion (including acquisitions) completed or on track to be completed generally on time and on budget;

Continued development of our potential future expansion project portfolio;

Excellent financial execution including capital raising and balance sheet and liquidity management while funding growth expenditures and maintaining dividend per share; and

A continued strong track record and performance regarding safety, including industry safety recognition in 2017 and strong compliance performance in all other aspects of our business, including environmental and regulatory compliance.

See "—Components of Executive Compensation Program for Fiscal 2017—Annual Incentive Bonus" for further discussion of certain of these summary highlights. Please also see our Annual Report on Form 10-K for the year ended December 31, 2017 for a reconciliation of Adjusted EBITDA to net income (loss) attributable to TRC.

Summary of 2017 and 2018 Compensation Decisions

While the compensation arrangements for our named executive officers during fiscal 2017 remained substantially similar to those in place during fiscal 2016, specific compensatory actions in 2017 included the following:

2017 Annual Bonus Pool and NEO Awards Paid in a Combination of Stock and Cash. Even though our overall performance on the 2017 business priorities significantly exceeded expectations for the year (as was the case for 2016), in light of the industry conditions in 2017 and early 2018 and continued uncertainty in the market, the bonus pool was funded at 160% of target under the 2017 Bonus Plan. In connection with this approval and our current focus on reducing cash expenses, the Compensation Committee approved settlement of the 2017 bonuses solely in restricted stock units awards for our Chief Executive Officer and our Executive Chairman of the Board ("Chairman"), instead of all-cash bonuses, and in a combination of 50% cash and 50% restricted stock unit awards, instead of all-cash bonuses, for all other executive officers including the other named executive officers. The restricted stock unit awards will vest in full three years after the date of grant of the award, subject to continued employment of the officers through that date. See "—Components of Executive Compensation Program for Fiscal 2017—Annual Incentive Bonus" for additional information.

Increases to 2017 Total Compensation and Increases to Base Pay. For 2017, base salary raises were approved for the named executive officers ranging from 3% to 46%. The Compensation Committee authorized base salary increases for the named executive officers 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 2017 Peer Group, adjusted for company size, and, in the case of Messrs. Meloy, McDonie, Muraro and Pryor, to reflect professional growth and the assumption of additional responsibilities. See "—Changes for 2017—2017 Peer Group" for a description of the companies that comprise the 2017 Peer Group. In addition, for 2017 under our annual incentive bonus plan, the target bonus percentages for our named executive officers were increased in order to align their total direct compensation more closely with the total direct compensation provided to similarly situated officers at companies within our 2017 Peer Group, adjusted for company size. For similar reasons, the long-term equity incentive award targets for 2017 for the named executive officers (other than Mr. Pryor) were also increased.

New Performance-Based Equity Award Component. For 2017, the Compensation Committee awarded long-term equity incentive awards in the form of both restricted stock unit awards and performance share unit awards under our Stock Incentive Plan. The vesting of the performance share units 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 overall performance period for the 2017 performance share units begins on January 1, 2017 and is designated to end on December 31, 2019, and the TSR performance factor is determined by the Compensation 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 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. 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 Compensation Committee in its discretion. Provided a named executive officer remains continuously employed through the end of 2019, the Officer will become vested, as soon as practicable following December 31, 2019, in a number of performance share units equal to the target number awarded multiplied by the TSR performance factor, and vested performance share units will be settled by the issuance of Company common stock. The Compensation Committee believes the performance share unit awards further align the interests of named executive officers and shareholders and provide meaningful incentives to the management team to consistently increase shareholder value over the long term.

Retention Awards and Special Incentive Award. In support of the Company's succession planning and management development goals, the Compensation Committee also awarded special retention awards in the form of 50,000 restricted stock units to Mr. Meloy, 45,000 restricted stock units to Mr. McDonie, 60,000 restricted stock units to Mr.

Muraro and 45,000 restricted stock units to Mr. Pryor on January 20, 2017. The Compensation Committee also awarded a special incentive award to Mr. Muraro based on his contributions and performance relating to special projects in the form of 25,000 restricted stock units on July 23, 2017, under an incentive program established prior to his appointment as an executive officer.

With respect to 2018 compensation, the Compensation Committee has made the following determinations, which are described in greater detail below under "—Changes for 2018":

• Increases to 2018 Total Compensation. For 2018, base salary raises were approved for the named executive officers ranging from 11% to 29%. The Compensation Committee authorized base salary increases for the named executive officers 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 2018 Peer Group, adjusted for company size, and, in the case of our named executive officers other than Mr. Perkins, to reflect their promotions to new positions and the assumption of additional responsibilities effective March 1, 2018. See "—Changes for 2018—2018 Peer Group" for a description of the companies that comprise the 2018 Peer Group. In addition, for 2018 under our annual incentive bonus plan, the target bonus percentages for our named executive officers were increased in order to align their total direct compensation more closely with the total direct compensation provided to similarly situated officers at companies within our 2018 Peer Group, adjusted for company size, and to reflect the changes in positions and responsibilities referenced above. For similar reasons, the long-term equity incentive award targets for 2018 for the named executive officers were also increased

Discussion and Analysis of Executive Compensation

Compensation Philosophy and Elements

The following compensation objectives guide the Compensation Committee in its deliberations about executive compensation matters:

Competition Among Peers. The Compensation Committee believes 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 energy industry companies as described in "—Methodology and Process—Role of Peer Group and Market Analysis" below.

Accountability for Performance. The Compensation Committee believes our executive compensation program should ensure an alignment between our strategic, operational and financial performance and the total compensation received by our named executive officers. 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. The Compensation Committee believes our executive compensation program should ensure a balance between short-term and long-term compensation while emphasizing at-risk or variable compensation as a valuable means of supporting our strategic goals and aligning the interests of our named executive officers with those of our shareholders.

Supportive of Business Goals. The Compensation Committee believes that our total compensation program should support our business objectives and priorities.

Consistent with this philosophy and the compensation objectives, our 2017 executive compensation program consisted of the following elements:

Compensation Element	Description	Role in Total Compensation
Base Salary	Competitive fixed-cash compensation based on an individual's role, experience, qualifications and performance	•A core element of competitive total compensation, important in attracting and retaining key executives
Annual Incentive Bonus	Variable payouts tied to achievement of annual financial, operational and strategic business priorities and determined in the sole discretion of the Compensation Committee	•Aligns named executive officers with annual strategic, operational and financial results •Recognizes individual and performance-based contributions to annual results •Supplements base salary to help attract and retain executives
Long-Term Equity Incentive Awards	Restricted stock awards granted under our Stock Incentive Plan Performance share unit awards granted under our Stock Incentive Plan	•Aligns named executive officers with sustained long-term value creation •Creates opportunity for a meaningful and sustained ownership stake •Combined with salary and annual bonus, provides a competitive target total direct compensation opportunity substantially contingent on our equity performance and performance relative to our LTIP peer group
Benefits	401(k) plan, health and welfare benefits	•Our named executive officers are eligible to participate in benefits provided to other Company employees •Contributes toward financial security for various life events (e.g., disability or death) •Generally competitive with companies in the midstream sector
Post-Termination Compensation	"Double trigger" change in control payments payable in cash Accelerated vesting of equity awards upon certain change in control transactions and qualifying termination events	•Helps mitigate possible disincentives to pursue value-added merger or acquisition transactions if employment prospects are uncertain •Provides assistance with transition if post-transaction employment is not offered

	Continued vesting of equity awards following retirement, subject to provision of consulting services or compliance with non-compete obligations	•Allows the Company to benefit from employee non-compete obligations and ongoing access to cooperative employees
Perquisites	None, other than minimal parking subsidies	•The Compensation Committee’s policy is not to pay for perquisites for any of our named executive officers, other than minimal parking subsidies

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Fiscal 2017 Total Direct Compensation

We review the mix of base salary, annual incentive bonuses and long-term equity incentive awards (i.e., total direct compensation) each year for the Company and for our Peer Group. We view the various components of total direct compensation as related but distinct and emphasize pay for performance, with a significant portion of total direct compensation reflecting a risk aspect tied to long- and short-term financial and strategic goals. Although we typically target annual long-term equity incentive awards as a percentage of base salary, we have historically not operated under any formal policies or specific guidelines for allocating compensation between long-term and currently paid out compensation, between cash and non-cash compensation, or among different forms of non-cash compensation. However, we believe that our compensation packages are representative of an appropriate mix of compensation components, and we anticipate that we will generally continue to utilize a similar, though not identical, mix of compensation in future years. As recommended by the Compensation Consultant, the Compensation Committee seeks to provide our named executive officers with a mix of base salary and short- and long-term incentives that is generally in line with that provided to similarly situated executives in our Peer Group, adjusted for company size.

The approximate allocation of target total direct compensation for our named executive officers in fiscal 2017 is presented below. This reflects (i) the salary rates in effect as of December 31, 2017, (ii) target annual incentive bonuses for services performed in fiscal 2017, and (iii) the grant date fair value of long-term equity incentive awards granted during fiscal 2017 (excluding the grant date fair value of equity awards granted in 2017 in lieu of 2016 annual incentive cash bonus payments).

Fiscal 2017 Target Total Direct Compensation

	Joe Bob Perkins	Matthew J. Meloy	Patrick J. McDonie	Robert M. Muraro	D. Scott Pryor
Base Salary	14%	22%	28%	31%	28%
Annual Incentive Bonus (1)	28%	24%	18%	19%	18%
Long-Term Equity Incentive Awards	58%	54%	54%	50%	54%
Total	100%	100%	100%	100%	100%

(1) Annual incentive bonuses actually paid with respect to performance in 2016 were paid 50% in cash and 50% in the form of restricted stock unit awards that will vest in full three years after the date of the award, subject to continued employment of the officers through that date.

Over the last five calendar years, the target total direct compensation (base salary plus target annual incentive bonus plus grant date fair value of long-term equity incentive awards) as set by the Compensation Committee for our Chief Executive Officer has resulted in target levels that have been significantly below the total direct compensation levels of similarly situated executives at companies in our Peer Group. The implied market median compensation level is determined by the Compensation Consultant using a regression analysis for our Peer Group that adjusts for company size and that predicts total direct compensation as correlated to market capitalization and total assets. The following chart illustrates the relationship between the target total direct compensation available to our Chief Executive Officer and the implied market median level and estimated top 25th percentile and top 10th percentile developed by our Compensation Consultant for the last five years:

Note: For the Total Direct Compensation Chart, the implied market median is shown as the solid blue bar, the estimated 75th percentile is shown as the light blue bar with dashed border, the 90th percentile is shown as the white bar with dotted border and the target compensation for our Chief Executive Officer is shown as the yellow bar.

Because incentive compensation (i.e., target annual incentive bonus and grant date fair value of long-term equity incentive awards) comprised 86% of our Chief Executive Officer's total direct compensation opportunity for 2017, the amount of compensation our Chief Executive Officer ultimately realizes from these awards may be more or less than the cash he would have received for the target amounts, as determined in particular by our Compensation Committee's evaluation of our performance and the performance of our common stock.

Annual Total Shareholder Return

In the last four calendar years, we have delivered annual total returns to our shareholders (share price appreciation plus dividends) of -7.2% (for 2017), 120.7% (for 2016), -71.3% (for 2015) and 23.3% (for 2014).

Methodology and Process

Role of Compensation Consultant in Setting Compensation

The Compensation Committee retained BDO as its independent Compensation Consultant to advise the Compensation Committee on matters related to executive and non-management director compensation for 2017. During 2016 and 2017, the Compensation Committee received advice from the Compensation Consultant with respect to the development and structure of our 2017 executive compensation program. As discussed above under "Meetings and Committees of Directors—Committees of the Board of Directors—Compensation Committee," the Compensation Committee has concluded that we do not have any conflicts of interest with the Compensation Consultant.

Role of Peer Group and Market Analysis

When evaluating annual compensation levels for each named executive officer, the Compensation Committee, with the assistance of the Compensation Consultant and senior management, reviews publicly available compensation data and analysis for executives in our Peer Group as well as the results of compensation surveys. The Compensation Committee then uses that information to help set compensation levels for the named executive officers in the context of their roles, levels of responsibility, accountability and decision-making authority within our organization and in the context of company size relative to the other Peer Group members. While compensation data from other companies is considered, the Compensation Committee and senior management do not attempt to set compensation components to meet specific benchmarks.

The Peer Group company data and analysis that is reviewed by senior management and the Compensation Committee is simply one factor out of many that is used in connection with the establishment of compensation opportunities for our officers. The other factors considered include, but are not limited to, (i) other available compensation data, rankings and comparisons for similarly situated officers, (ii) effort and accomplishment on a group and individual basis, (iii) challenges faced and challenges overcome, (iv) unique skills, (v) contribution to the management team and (vi) the perception of both the Board of Directors and the Compensation Committee of our performance relative to expectations and actual market/business conditions. All of these factors, including Peer Group company data and analysis, are utilized in a subjective assessment of each year's decisions relating to base salary, annual incentive bonus and long-term equity incentive award decisions.

To reflect the market in which we compete for executive talent, the Peer Group considered by the Compensation Committee in consultation with senior management for compensation comparison purposes for 2017 included companies in three comparator groups: (1) midstream companies ("Midstream Companies"), (2) exploration and production companies ("E&Ps"), and (3) energy utilities, and our analysis placed greater weight on the compensation data reported by other publicly-traded Midstream Companies. E&Ps and utilities selected for the Peer Group, in the Compensation Committee's opinion, provide 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 executive officers.

Because companies in the Peer Group are larger or smaller than we are as measured by market capitalization and total assets, with the assistance of the Compensation Consultant, compensation data for the Peer Group companies is analyzed using multiple regression analysis to develop a prediction of the total compensation that Peer Group companies of comparable size to us would offer similarly-situated executives. For 2017, the regressed data was analyzed separately for each of the three comparator groups and then weighted as follows to develop reference points for assessing our total executive pay opportunity relative to market practice: (1) Midstream Companies (given a 70% weighting), (2) E&Ps (given a 15% weighting) and (3) utility companies (given a 15% weighting). More traditional benchmarks of Midstream Companies without regression are also considered, along with survey results, comparisons with individual companies and positions, and the distribution of such data and analysis. For 2017, the "Peer Group" companies (for purposes of determining 2017 compensation levels) were:

Midstream Companies (the "2017 Midstream Peer Group"): Boardwalk Pipeline Partners, L.P., Buckeye Partners, L.P., Crestwood Equity Partners, L.P., DCP Midstream Partners, L.P., Enable Midstream Partners, L.P., Energy Transfer Equity, L.P., EnLink Midstream Partners, L.P., Enterprise Products Partners L.P., Genesis Energy, L.P., Holly Energy Partners, L.P., Kinder Morgan, Inc., Magellan Midstream Partners, L.P., NuStar Energy L.P., ONEOK, Inc., Plains GP Holdings, L.P., SemGroup Corporation , Spectra Energy Corp., Summit Midstream Partners, L.P., Tallgrass Energy Partners, LP and Williams Companies, Inc.

E&P peer companies: Apache Corporation, Cabot Oil & Gas Corporation, Cimarex Energy Company, Concho Resources, Inc., Continental Resources, Inc., Denbury Resources Inc., Devon Energy Corporation, Diamondback Energy, Inc., Energen Corp., EOG Resources, Inc., Murphy Oil Corporation, Newfield Exploration Company, Noble Energy, Inc., Parsley Energy, Inc., Pioneer Natural Resources Company, QEP Resources, Inc., Range Resources Corporation, RSP Permian, Inc., SM Energy Company, Southwestern Energy Company and WPX Energy, Inc.

Utility peer companies: AGL Resources, Inc., Ameren Corporation, Atmos Energy Corporation, CenterPoint Energy, Inc., Dominion Resources, Inc., DTE Energy Company, Enbridge Inc., Entergy Corporation, EQT Corporation, National Fuel Gas Company, NiSource Inc., Questar Corporation, Sempra Energy, Spectra Energy Corp.,TransCanada Corporation and Xcel Energy Inc.

Periodically we make changes in the Peer Group to reflect the change in ownership status or size of some of the peer companies, to include additional companies and/or to create more balance in the make-up of the Peer Group. Based upon the recommendation of our Compensation Consultant, we removed the peer companies listed in the table immediately below that were previously included in the 2016 Peer Group, in order to create the 2017 Peer Group. Many of the aforementioned companies were subsidiary master limited partnerships that have been replaced with their public parent corporations, with such parent corporations included in the second table below:

Midstream	E&P	Utilities
Access Midstream Partners, L.P.	Halcon Resources Corp.	Spectra Energy Corp.
Enbridge Energy Partners, L.P.	Ultra Petroleum Corp.	
Energy Transfer Partners, L.P.		
MarkWest Energy Partners, L.P.		
Plains All American Pipeline, L.P.		
Regency Energy Partners, L.P.		

In addition, we added the peer companies listed in the following table to the 2017 Peer Group:

Midstream	E&P	Utilities
Energy Transfer Equity, L.P.	Concho Resources, Inc.	Entergy Corporation
Holly Energy Partners, L.P.	Continental Resources, Inc.	Xcel Energy Inc.
Kinder Morgan, Inc.	Diamondback Energy, Inc.	
Plains GP Holdings, L.P.	Energen Corp.	
SemGroup Corporation	Parsley Energy, Inc.	
Spectra Energy Corp.	Range Resources Corporation	
Tallgrass Energy Partners, LP	RSP Permian, Inc.	
	WPX Energy, Inc.	

Senior management and the Compensation Committee review our compensation-setting practices and Peer Group companies on at least an annual basis. See "—Changes for 2018—2018 Peer Group" for a description of the changes that were made to the Peer Group for 2018 compensation purposes.

Role of Senior Management in Establishing Compensation for Named Executive Officers

Typically, under the direction of the Compensation Committee, senior management consults with the Compensation Consultant and reviews market data and evaluates relevant compensation levels and compensation program elements towards the end of each fiscal year. Based on these consultations and assessments of performance relative to our business priorities, senior management submits emerging conclusions to the Chairman of the Compensation Committee, meets periodically with the full Compensation Committee together with Compensation Consultant relative to process and performance, and subsequently, provides a proposal to the Chairman of the Compensation Committee. The proposal includes a recommendation of base salary, target annual incentive bonus opportunity and long-term equity incentive awards to be paid or awarded to executive officers for the next fiscal year. In addition, the proposal includes a recommendation regarding the annual incentive bonus amount to be paid for the current fiscal year.

The Chairman of the Compensation Committee reviews and discusses the proposal with senior management and the Compensation Consultant and may discuss it with the other members of the Compensation Committee, other members of the Board of Directors and/or the full Board of Directors. The Chairman of the Compensation Committee may request that senior management provide him with additional information or reconsider or revise the proposal. The resulting recommendations are then submitted for consideration to the full Compensation Committee, which typically meets separately with the Compensation Consultant and typically discusses the recommendations with the other members of the Board of Directors. The final compensation decisions for the named executive officers are made by the Compensation Committee and reported to the Board of Directors.

Our senior management members typically have no other role in determining compensation for our named executive officers. The Compensation Committee may delegate the approval of equity-based award grants and other transactions and responsibilities regarding the administration of our equity compensation program to the Executive Chairman of the Board or the Chief Executive Officer with respect to employees other than our Section 16 officers. Our executive officers are delegated the authority and responsibility to determine the compensation for all other employees.

Components of Executive Compensation Program for Fiscal 2017

Base Salary

The base salaries for our named executive officers are set and reviewed annually by the Compensation Committee. Base salaries for our named executive officers have been established based on Peer Group analysis and historical salary levels for these officers, as well as the relationship of their salaries to those of our other executive officers, taking into consideration the value of the total direct compensation opportunities available to our executive officers, including the annual incentive bonus and long-term equity incentive award components of our compensation program. The other factors listed above under "—Methodology and Process—Role of Peer Group and Market Analysis" are also considered.

For 2017, the Compensation Committee authorized base salary increases for certain of the named executive officers 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 2017 Peer Group, adjusted for company size, and, in the case of Messrs. Meloy, McDonie, Muraro and Pryor, to reflect professional growth and the assumption of additional responsibilities. The 2017 base salary rates for our named executive officers were as follows:

	Prior Salary	Base Salary Effective March 1, 2017	Percent Increase (approximate)
Joe Bob Perkins	$725,000	$750,000	3%
Matthew J. Meloy	460,000	475,000	3%
Patrick J. McDonie	410,800	425,000	3%
Robert M. Muraro	240,000	350,000	46%
D. Scott Pryor	390,000	425,000	9%

Annual Incentive Bonus

For 2017, our named executive officers were eligible to receive annual incentive bonuses under the 2017 Annual Incentive Compensation Plan (the "2017 Bonus Plan"), which was approved by the Compensation Committee in January 2017. The funding of the bonus pool and the payment of individual bonuses to executive management, including our named executive officers, are subject to the sole discretion of the Compensation Committee (following recommendations from our Chief Executive Officer) and will generally be determined near or following the end of the year to which the bonus relates.

Target Bonus Amounts. Each named executive officer's target bonus amount is equal to the product of the officer's base salary (at the rate in effect as of the last day of the year to which the bonus relates) and the officer's target bonus percentage. For purposes of the 2017 Bonus Plan, the percentage of base salary that was set as the "target" amount for each named executive officer's bonus was as follows:

	Target Bonus Percentage (as a % of Base Salary)	Target Bonus Amount
Joe Bob Perkins	190%	$1,425,000
Matthew J. Meloy	110%	522,500
Patrick J. McDonie	65%	276,250
Robert M. Muraro	60%	210,000
D. Scott Pryor	65%	276,250

For 2017, the target bonus percentage for each named executive officer was increased to align his total direct compensation more closely with the total direct compensation provided to similarly situated executives.

The Chief Executive Officer and the Compensation Committee relied on the Compensation Consultant and market data from Peer Group companies and broader industry compensation practices to establish the target bonus percentages for the named executive officers and the applicable threshold, target and maximum percentage levels for funding the bonus pool, which are generally consistent with both Peer Group company and broader energy compensation practices.

2017 Bonus Plan Funding Level and Assessment of Business Priorities. The Compensation Committee, after consultation with the Chief Executive Officer, established the following overall threshold, target and maximum levels for the 2017 Bonus Plan: (i) 50% of the target amount of the bonus pool would be funded in the event that the Compensation Committee determined that our business priorities had been met for the year at a threshold level; (ii) 100% of the target amount of the bonus pool would be funded in the event that the Compensation Committee determined that our business priorities had been met for the year at a target level; and (iii) 200% of the target amount of the bonus pool would be funded in the event that the Compensation Committee determined that our business priorities had been met for the year at a maximum level. While the established threshold, target and maximum levels provide general guidelines in determining the funding level of the bonus pool each year, senior management recommends a funding level to the Compensation Committee based on our achievement of specified business priorities for the year and other factors, and the Compensation Committee ultimately determines the total amount to be allocated to the bonus pool in its sole discretion based on its assessment of the business priorities and our overall performance for the year.

For purposes of determining the actual funding level of the bonus pool and the amount of individual bonus awards under the 2017 Bonus Plan, the Compensation Committee focused on the business priorities listed in the table below. The 2017 business priorities are the same eight business priorities as in effect for 2016, except that the priority related to executing on all business dimensions has been refined to include the 2017 business plan and public guidance. These priorities are not objective in nature — they are subjective, and performance in regard to these priorities is ultimately evaluated by the Compensation Committee in its sole discretion, informed by monthly and quarterly reports from management and ongoing dialogue concerning the priorities. As such, success does not depend on achieving a particular target; rather, success is evaluated based on past norms, expectations and unanticipated obstacles or opportunities that arise. For example, hurricanes and deteriorating or changing market conditions may alter the priorities initially established by the Compensation Committee such that certain performance that would otherwise be deemed a negative may, in context, be a positive result. This subjectivity allows the Compensation Committee to account for the full industry and economic context of our actual performance and that of our personnel. The Compensation Committee considers all strategic priorities and reviews performance against the priorities and context but does not apply a formula or assign specific weightings to the strategic priorities in advance.

2017 Business Priority	Committee Consensus	Overall Assessment
Execute on all business dimensions, including the 2017 business plan and public guidance	Strongly Achieved	•Excellent execution across our businesses •Year-over-year volume growth of about 7% for Field G&P and 19% for Permian; fractionation volumes increased 15% •Met guidance for LPG exports, and dividend coverage guidance of 1.0x – 0.95x (provided during the year) •Excellent balance sheet and liquidity management while funding approximately $2 billion in capital expenditures including acquisitions and maintaining flat dividend per share •Very strong commercial and operational customer focus during the year including leading up to, during and following Hurricane Harvey
Continue priority emphasis and strong performance relative to a safe workplace	Strongly Achieved	•Strong track record and performance regarding safety and compliance in all aspects of our business, including ongoing training and environmental and regulatory compliance; continued industry recognition through safety awards
Reinforce business philosophy and mindset that promote compliance in all aspects of our business including environmental and regulatory compliance	Exceeded	•Remediated controls over the preparation and review of income tax provisions for interim periods; improved ES&H organization and processes to respond to growth; received industry recognition and awards for safety and compliance practices.
Continue to attract and retain the operational and professional talent needed in our businesses	Exceeded	•Successful talent hiring and retention while continuing organizational realignments to streamline operations, manage growth and to provide development opportunities for employees
Continue to control all costs—operating, capital and general and administrative (“G&A”) consistent with the existing business environment	Exceeded	•Continued focus on controlling costs, total operating expenditures are modestly higher after adjusting for acquisition despite significant increase in assets and volumes
Execute on major capital and development projects—finalizing negotiations, completing projects on time and on budget, and optimizing economics and capital funding	Exceeded	•2017 capital expenditures of about $2 billion (including acquisitions) completed or on track to be completed generally on or ahead of schedule and on or below budget, including •Start-up of Raptor Plant in South Texas and expansion of plant from 200 MMcf/d to 260 MMcf/d •Ongoing construction of Noble Crude and Condensate Splitter; Joyce and Johnson Processing Plants in WestTX;

	and Wildcat Processing Plant •Oahu Processing Plant in Delaware Basin slightly behind schedule but with minimal impact to the Company as gas is currently being handled by existing Company facilities •Significantly expanded the Badlands gas capacity off the reservation to the Little Missouri Plant •Expanded the Badlands oil takeaway capacity by connecting to DAPL at Johnsons Corner

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2017 Business Priority	Committee Consensus	Overall Assessment
Pursue selected growth opportunities, including gathering and processing (“G&P”) build outs, fee-based capital expenditure projects, and potential purchases of strategic assets	Strongly Exceeded	•Strategic acquisitions, closed and integrated: •Outrigger’s Midland and Delaware Basin G&P and crude oil gathering operations •Boardwalk’s South Texas G&P assets in the Eagle Ford •Agreements for several strategic joint ventures, completed in 2017 or early 2018 •Grand Prix: EagleClaw / Blackstone •Gulf Coast Express: Kinder / DCP •Badlands: Hess Midstream •SouthOK: MPLX •Continued development of our potential future expansion project portfolio
Pursue commercial and financial approaches to achieve maximum value and manage risks, including contract, credit, inventory, interest rate and commodity price exposures	Exceeded	•Strong credit, inventory, hedging and balance sheet management •Insignificant write offs and proactive management of contractual relationships associated with customer financial issues •Increased volumes and margins in Field G&P through contract renewals and new dedications

After assessing the results of the 2017 business priorities as summarized above, the Compensation Committee determined in January 2018 that overall performance relative to the 2017 business priorities substantially exceeded expectations. This subjective assessment that performance substantially exceeded expectations was based on a qualitative business assessment rather than a mechanical, quantitative determination of results across each of the business priorities, and occurred with the background and ongoing context of (i) refinements of the 2017 business priorities by the Board of Directors and the Compensation Committee, (ii) continued discussion and active dialogue among the Board of Directors and the Compensation Committee and management about priorities and performance, including routine reports sent to the Board of Directors and the Compensation Committee, (iii) detailed monthly performance communications to the Board of Directors, (iv) presentations and discussions in subsequent Board of Directors and Compensation Committee meetings, and (v) further discussion among the Board of Directors and Compensation Committee of our performance relative to expectations near the end and following the end of 2017. The extensive business and board of director experience of the members of the Compensation Committee and of our Board of Directors provides the perspective to make this subjective assessment in a qualitative manner and to evaluate overall management performance and the performance of individual executive officers.

Based on the Compensation Committee's assessment of overall performance of the 2017 business priorities, the Compensation Committee, in its sole discretion, approved an annual bonus pool equal to 160% of the target level under the 2017 Bonus Plan.

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 2017. As a result, the Compensation Committee determined that a performance multiplier of 1.0x should be applied to each named executive officer for 2017 based on the Officer's individual performance and performance as part of the executive team.

Settlement of 2017 Bonus Awards . In light of the current industry market conditions and the Company's resulting focus on reducing cash expenses, the Compensation Committee also approved settlement of the 2017 bonuses solely in restricted stock units awards for our Chief Executive Officer and our Chairman, instead of all-cash bonuses, and in a combination of cash and restricted stock unit awards, instead of all-cash bonuses, for all other executive officers including the other named executive officers . All other employees of the Company and its subsidiaries received payment of their awards under the 2017 Bonus Plan solely in the form of cash .

Specifically, the Compensation Committee determined that 100% of our Chief Executive Officer's and our Chairman's total bonus would be settled in the form of restricted stock unit awards, resulting in these officers receiving restricted stock unit awards corresponding to approximately 160% of their respective target bonus amounts under the 2017 Bonus Plan. Approximately 50% of each other executive officer's total bonus amount would be settled in the form of restricted stock unit awards, resulting in these officers receiving restricted stock unit awards corresponding to approximately 80% of their respective target bonus amounts under the 2017 Bonus Plan. The number of restricted stock units awarded to each named executive officer was determined by dividing the total dollar value allocated to the equity portion of the bonus amount by the ten-day average closing price of the shares of common stock measured over a period of time prior to the date of grant. 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 and the recipients of the awards will receive a cash payment during the period that the awards are outstanding equal to each dividend paid with respect to a share of common stock times the number of restricted stock units awarded. The following table reflects the awards actually received by our named executive officers under the 2017 Bonus Plan, including the value of restricted stock unit awards received:

	Target Bonus Amount	Individual Performance Factor	Company Performance Factor	Total Bonus Amount To Be Received	Cash Amount to be Paid	Approximate Value and Number of Restricted Stock Units Awarded
Joe Bob Perkins	$1,425,000	1.0	1.6	$2,280,000		$2,280,000 (45,831 RSUs)
Matthew J. Meloy	522,500	1.0	1.6	836,000	$418,000	418,000 (8,402 RSUs)
Patrick J. McDonie	276,250	1.0	1.6	442,000	221,000	221,000 (4,442 RSUs)
Robert M. Muraro	210,000	1.0	1.6	336,000	168,000	168,000 (3,377 RSUs)
D. Scott Pryor	276,250	1.0	1.6	442,000	221,000	221,000 (4,442 RSUs)

Long-Term Equity Incentive Awards

In connection with our initial public offering in December 2010, we adopted the 2010 Stock Incentive Plan (the "Stock Incentive Plan") under which we may grant to the named executive officers, other key employees, consultants and directors certain equity-based awards, including restricted stock, restricted stock units, bonus stock and performance-based awards. At the 2017 Annual Meeting, our shareholders approved the amendment and restatement of the Stock Incentive Plan in order to extend the term of the Stock Incentive Plan and make available additional shares of common stock for the future grant of equity-based awards to our officers, employees, consultants and directors.

In addition, prior to the Buy-In Transaction, the General Partner sponsored and maintained the Targa Resources Partners Long-Term Incentive Plan (the "Long-Term Incentive Plan"), under which the General Partner could grant equity-based awards related to the Partnership's common units to individuals, including the named executive officers, who provide services to the Partnership. In connection with the Buy-In Transaction, we adopted and assumed the 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 "Equity Compensation Plan"). We 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, the Company no longer intends to continue making grants under the plan.

Form and Amount of Equity Awards. Long-term equity incentive awards to our named executive officers under the Stock Incentive Plan are generally made near the beginning of each year. For 2017, the Compensation Committee awarded long-term equity incentive awards in the form of both restricted stock unit and performance share unit awards under our Stock Incentive Plan. The vesting of the performance share units is dependent on the satisfaction of a combination 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 2017, the value of the long-term equity incentive component of our named executive officers' compensation was allocated approximately (i) fifty percent (50%) to restricted stock unit awards under the Stock Incentive Plan and (ii) fifty percent (50%) to equity-settled performance share unit awards under the Stock Incentive Plan.

The Compensation Committee determines the amount of long-term equity incentive awards under the Stock Incentive Plan that it believes are appropriate as a component of total compensation for each named executive officer based on its decisions regarding each named executive officer's total compensation targets. The total dollar value of long-term equity incentive awards for each named executive officer for a given year is typically equal to a specified percentage of the officer's base salary; however, the Compensation Committee may, in its discretion, award additional long-term equity incentive awards if deemed appropriate. 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 of time prior to the date of grant. For executive awards granted in 2017, the specified percentage of each named executive officer'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:

	Percentage of Base Salary	Total Dollar Value of Long-Term Equity Incentive Awards
Joe Bob Perkins	400%	$3,000,000
Matthew J. Meloy	250%	1,187,500
Patrick J. McDonie	190%	807,500
D. Scott Pryor	190%	807,500

For 2017, the Compensation Committee approved increases in the percentage of base salary used to determine the total dollar value of the annual long-term equity incentive awards granted to the named executive officers.

2017 Restricted Stock Unit Awards. On January 20, 2017, our named executive officers were awarded equity-settled restricted stock units under the Stock Incentive Plan in the following amounts: (i) 25,742 restricted stock units to Mr. Perkins, (ii) 10,190 restricted stock units to Mr. Meloy, (iii) 6,929 restricted stock units to Mr. McDonie and (iv) 6,929 restricted stock units to Mr. Pryor. For 2017, Mr. Muraro received a grant of 7,500 restricted stock units prior to his appointment as an executive officer. These restricted stock units vest in full on the third anniversary of the grant date, subject to the officer's continued service or if, from the date of the executive's retirement through the third anniversary of the grant date, the executive 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 Compensation Committee believes these continued vesting provisions following retirement allow the Company to benefit from employee non-compete obligations and ongoing access to cooperative employees, further align our executives' interests with those of our shareholders and help attract and retain key employees.

Accelerated vesting provisions applicable to these awards in the event of certain terminations of employment and/or a change in control are described in detail below under "Executive Compensation—Potential Payments Upon Termination or Change in Control—Stock Incentive Plan."During the period the restricted stock units are outstanding and unvested, we accrue any dividends paid by us in an amount equal to the dividends paid with respect to a share of common stock times the number of restricted stock units awarded. At the time the restricted stock units vest, the named executive officers will receive a cash payment equal to the amount of dividends accrued with respect to such named executive officer's vested restricted stock units.

Equity-Settled Performance Share Units. On January 20, 2017, our named executive officers were awarded equity-settled performance share units under the Stock Incentive Plan in the following target amounts: (i) 25,742 performance share units to Mr. Perkins, (ii) 10,190 performance share units to Mr. Meloy, (iii) 6,929 performance share units to Mr. McDonie and (iv) 6,929 performance share units to Mr. Pryor. For 2017, Mr. Muraro received a grant of 7,500 performance share units prior to his appointment as an executive officer. 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. The performance share units, which are designed to settle in shares of Company common stock, are intended to further align the interests of the named executive officers and other executive officers with those of the Company's shareholders and provide meaningful incentives to the management team to consistently increase shareholder value over the long term.

The vesting of these awards is 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 2017 performance share units, the LTIP Peer Group is composed of the Company and the following other companies:

Boardwalk Pipeline Partners L.P.	NuStar Energy, L.P.
Buckeye Partners, L.P.	ONEOK, Inc.
DCP Midstream Partners L.P.	Plains GP Holdings, L.P.
Enable Midstream Partners L.P.	Tallgrass Energy Partners, L.P.
EnLink Midstream Partners L.P.	Williams Companies, Inc.
Genesis Energy, L.P.	

The LTIP Peer Group is a subset of the 2017 Midstream Peer Group modified to include only those 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 overall performance period for the 2017 performance share units begins on January 1, 2017 and is designated to end on December 31, 2019, and the TSR performance factor is determined by the Compensation 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 relative TSR over the entirety of the three-year performance period. 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. For performance results in an applicable weighting period that fall between (i) the 1st percentile and the 25th percentile of the LTIP Peer Group, the guideline performance percentage would be 0%, (ii) the 25th percentile and the 50th percentile, the guideline performance percentage would be interpolated between 50% and 100%, and (iii) the 50th percentile and 75th percentile, the guideline performance percentage would be interpolated between 100% and 250%. If the Company's performance was above the 75th percentile of the LTIP Peer Group for the applicable period, the guideline performance percentage would be 250%.

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 Compensation Committee in its discretion 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, relative TSR performance is determined based on the comparison of "total return" of a share of the Company's common stock for the applicable period to the "total return" of a common share/unit of each member of the LTIP Peer Group for the performance period, measured based on (i) the average closing price of each company's share/unit for the first ten trading days of the applicable period, and (ii) the sum of (a) the average closing price for each company's share/unit for the first ten trading days immediately following the last day of the applicable period (or, in the discretion of the Compensation Committee, for a specified consecutive ten day trading period during the last month of the applicable period), plus (b) the aggregate amount of dividends/distributions paid with respect to such share/unit during such period.

Provided a named executive officer remains continuously employed through the end of 2019, he will become vested, as soon as practicable following December 31, 2019, in a number of performance share units equal to the target number awarded multiplied by the TSR performance factor, and vested performance share units will be settled by the issuance of Company common stock. In addition, a named executive officer will be considered to have remained continuously employed if, from the date of the executive's retirement through the end of 2019, the executive 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 would be permitted). The performance share units would remain subject to the applicable performance-based vesting requirements described above during such period.

Accelerated vesting provisions applicable to these awards in the event of certain terminations of employment and/or a change in control are described in detail below under "Executive Compensation—Potential Payments Upon Termination or Change in Control—Stock Incentive Plan." During the overall performance period for which the performance share units are outstanding, the Company accrues any cash dividends paid by the Company to holders of common stock in an amount equal to the cash dividends paid with respect to a share of common stock times the target number of performance share units awarded. At the time the performance share units are settled, the named executive officers would also receive a cash payment equal to the product of the amount of cash dividends accrued with respect to a share of common stock times the TSR performance factor.

Retention Awards and Special Incentive Award. In support of the Company's succession planning and management development goals, on January 20, 2017, the Compensation Committee also awarded special retention awards to certain executive officers. The special retention awards were granted in the form of restricted stock units that vest 30%, 30% and 40% on the fourth, fifth and sixth anniversaries, respectively, of the date of grant of the awards, subject to continued employment. The following executive officers were granted restricted stock units as special retention awards under the Stock Incentive Plan in the following amounts: (i) 50,000 restricted stock units to Mr. Meloy, (ii) 45,000 restricted stock units to Mr. McDonie, (iii) 60,000 restricted stock units to Mr. Muraro (prior to his appointment as an executive officer) and (iv) 45,000 restricted stock units to Mr. Pryor. On July 23, 2017, the Compensation Committee also awarded a special incentive award to Mr. Muraro based on his contributions and performance under a special project incentive program that was established prior to his appointment as an executive officer. The special incentive award to Mr. Muraro was in the form of 25,000 restricted stock units that vest in full on the third anniversary of the grant date, subject to his continued service or if, from the date of his retirement through the third anniversary of the grant date, he 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).

Severance and Change in Control Benefits

The Executive Officer Change in Control Program (the “Change in Control Program”), in which each of our named executive officers is eligible to participate, provides for post-termination payments following a qualifying termination of employment in connection with a change in control event, or what is commonly referred to as a “double trigger” benefit. The vesting of certain of our long-term equity incentive compensation awards accelerates upon a change in control irrespective of whether the officer is terminated, and/or upon certain termination of employment events, such as death, disability or a termination by us without cause. Please see “Executive Compensation—Potential Payments Upon Termination or Change in Control” below for further information.

We believe that the Change in Control Program and the accelerated vesting provisions of our long-term equity incentive awards are important retention tools for us and are consistent with practices common among our industry peers. Accelerated vesting of long-term equity incentive awards upon a change in control enables our named executive officers to realize value from these awards consistent with value created for investors upon the closing of a transaction. In addition, we believe that post-termination benefits may, in part, mitigate some of the potential uncertainty created by a potential or actual change in control transaction, including with respect to the future employment of the named executive officers, thus allowing management to focus on the business transaction at hand.

Retirement, Health and Welfare, and Other Benefits

We offer eligible employees participation in a section 401(k) tax-qualified, defined contribution plan (the “401(k) Plan”) to enable employees to save for retirement through a tax-advantaged combination of employee and company contributions and to provide employees the opportunity to directly manage their retirement plan assets through a variety of investment options. Our employees, including our named executive officers, are eligible to participate in our 401(k) Plan and 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) and have it contributed to the 401(k) Plan, 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 named executive officers: (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 named executive officers or other employees.

All full-time employees, including our named executive officers, 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 named executive officers, other than minimal parking subsidies.

Changes for 2018

In consultation with the Compensation Consultant, the Compensation Committee has reviewed our executive compensation program and has made certain changes for 2018, which are described in more detail below. The analysis provided by the Compensation Consultant indicated that the total target direct compensation of our Chief Executive Officer and our other named executive officers, who are being promoted to new positions and will assume additional responsibilities effective March 1, 2018, was below the total direct compensation levels of similarly situated executives at companies in our Peer Group, considering for example, the Peer Group pay programs adjusted for size using a regression analysis along with other available surveys and analysis.

In order to align the total compensation of our named executive officers more closely with that of similarly situated officers the Compensation Committee has approved increases in the salary levels and the incentive-based compensation opportunities of the named executive officers as described below.

2018 Peer Group

In light of significant changes to companies in the overall industries in which we operate and compete for executive talent and based upon the recommendation of our Compensation Consultant, during our annual reconsideration of the peer group, we made certain changes to the 2017 Peer Group used for compensation comparison purposes to create the 2018 Peer Group. We believe the 2018 Peer Group provides a more relevant and complete set of peers based on changes in the current circumstances of the included companies, including such companies' size, organization, operations, market presence, business challenges and completed or announced corporate transactions.

Specifically, we removed the peer companies listed in the following table that were previously included in the 2017 Peer Group:

Midstream	E&P	Utilities
Crestwood Equity Partners, L.P.	Denbury Resource Inc.	AGL Resources, Inc.
Holly Energy Partners, L.P.	Energen Corp.	Questar Corporation
SemGroup Corporation		
Summit Midstream Partners, L.P.		
Spectra Energy Corp.		

In addition, we added the peer companies listed in the following table to the 2018 Peer Group:

Midstream	E&P	Utilities
Tesoro Corporation	Chesapeake Energy Corporation	MDU Resources Group, Inc.
	Hess Corporation	Public Service Enterprise Group Inc.
	Marathon Oil Corporation	SCANA Corporation

As a result of the above changes, the 2018 Peer Group companies (for purposes of determining 2018 compensation levels) are:

Midstream Companies: Boardwalk Pipeline Partners, L.P., Buckeye Partners, L.P., , DCP Midstream Partners, L.P., Enable Midstream Partners, L.P., L.P., Energy Transfer Equity, L.P., EnLink Midstream Partners, L.P., Enterprise Products Partners L.P., Genesis Energy, L.P., Kinder Morgan, Inc., Magellan Midstream Partners, L.P., NuStar Energy L.P., ONEOK, Inc., Plains GP Holdings, L.P., Tallgrass Energy Partners, L.P., Tesoro Corporation and Williams Companies, Inc.

E&P peer companies: Apache Corporation, Cabot Oil & Gas Corporation, Chesapeake Energy Corporation, Cimarex Energy Company, Concho Resources, Inc., Continental Resources, Inc., Devon Energy Corporation, Diamondback Energy, Inc., EOG Resources, Inc., Hess Corporation, Marathon Oil Corporation, Murphy Oil Corporation, Newfield Exploration Company, Noble Energy, Inc., Parsley Energy, Inc., Pioneer Natural Resources Company, QEP Resources, Inc., Range Resources Corporation, RSP Permian, Inc., SM Energy Company, Southwestern Energy Company and WPX Energy, Inc.

Utility peer companies: Ameren Corporation, Atmos Energy Corporation, CenterPoint Energy, Inc., Dominion Resources, Inc., DTE Energy Company, Enbridge Inc., Entergy Corporation, EQT Corporation, National Fuel Gas Company, NiSource Inc., MDU Resources Group, Inc., Public Service Enterprise Group Inc., SCANA Corporation, Sempra Energy, TransCanada Corporation and Xcel Energy Inc.

Base Salary

The Compensation Committee has authorized, and executive management will implement, the following base salaries for our named executive officers effective March 1, 2018:

	Effective March 1, 2018	Current Salary
Joe Bob Perkins	$850,000	$750,000
Matthew J. Meloy	525,000	475,000
Patrick J. McDonie	475,000	425,000
Robert M. Muraro	450,000	350,000
D. Scott Pryor	475,000	425,000

The Compensation Committee authorized base salary increases for the named executive officers, along with certain adjustments in annual bonus incentive targets and grant date fair values of long-term equity incentive awards (as described below), in order to align the total direct compensation of these individuals more closely with the total direct compensation provided to similarly situated executives, and in the case of Messrs. Meloy, McDonie, Muraro and Pryor, to reflect their promotions and the assumption of additional responsibilities.

Annual Incentive Bonus

In preparing our business plan for 2018, senior management developed and proposed a set of business priorities to the Compensation Committee. The Compensation Committee discussed and adopted the business priorities proposed by senior management for purposes of the 2018 Annual Incentive Compensation Plan (the "2018 Bonus Plan"). The 2018 business priorities are the same eight business priorities as in effect for 2017, except that the priority related to execution on major capital and development projects has been modified to add staffing for the new facilities.

The overall threshold, target and maximum funding percentages for the 2018 Bonus Plan remain the same as for the 2017 Bonus Plan. The target bonus percentages of the named executive officers have been increased for 2018. The following table shows the target bonus percentages for our named executive officers effective March 1, 2018:

	Effective March 1, 2018	Current Percentage
Joe Bob Perkins	200%	190%
Matthew J. Meloy	125%	110%
Patrick J. McDonie	100%	65%
Robert M. Muraro	100%	60%
D. Scott Pryor	100%	65%

As with the 2017 Bonus Plan, funding of the bonus pool and the payment of individual bonuses to executive management, including our named executive officers, is subject to the sole discretion of the Compensation Committee.

Long-Term Equity Incentive Awards

The Compensation Committee also approved increases in the percentage of base salary used to determine the total dollar value of the annual long-term equity incentive awards granted to the named executive officers. The following table shows the new percentages approved for long-term incentive awards for our named executive officers effective for 2018:

	2018 Percentage	Current Percentage
Joe Bob Perkins	550%	400%
Matthew J. Meloy	500%	250%
Patrick J. McDonie	250%	190%
Robert M. Muraro	250%	160%
D. Scott Pryor	250%	190%

For 2018, the Compensation Committee determined to grant a combination of restricted stock units and performance share units to our named executive officers under the Stock Incentive Plan. Specifically, for 2018, the value of the long-term equity incentive component of our named executive officers' compensation was allocated approximately (A) 50% to restricted stock units and (B) 50% to performance share units.

Restricted Stock Unit Awards. On January 17, 2018, our named executive officers were awarded equity-settled restricted stock units under the Stock Incentive Plan in the following amounts: (i) 46,987 restricted stock units to Mr. Perkins, (ii) 26,383 restricted stock units to Mr. Meloy, (iii) 11,935 restricted stock units to Mr. McDonie, (iv) 11,307 restricted stock units to Mr. Muraro and (v) 11,935 restricted stock units to Mr. Pryor. 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. These restricted stock units vest in full on the third anniversary of the grant date, subject to the officer's continued service or fulfillment of certain service related requirements following retirement.

Equity-Settled Performance Share Units. Our named executive officers also received an annual award of equity-settled performance share units under the Stock Incentive Plan for 2018. On January 17, 2018, our named executive officers were awarded equity-settled performance share units under the Stock Incentive Plan in the following target amounts: (i) 46,987 performance share units to Mr. Perkins, (ii) 26,383 performance share units to Mr. Meloy, (iii) 11,935 performance share units to Mr. McDonie, (iv) 11,307 performance share units to Mr. Muraro and (v) 11,935 performance share units to Mr. Pryor. 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. The performance share units, which are designed to settle in shares of Company common stock, are intended to further align the interests of the named executive officers and other executive officers with those of the Company's shareholders and provide meaningful incentives to the management team to consistently increase shareholder value over the long term. Please see "—Components of Executive Compensation Program for Fiscal 2017—Long-Term Equity Incentive Awards— Equity-Settled Performance Share Units."

The vesting of these awards is 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 2018 performance share units, the LTIP Peer Group is composed of the Company and the following other companies:

Boardwalk Pipeline Partners L.P.	NuStar Energy, L.P.
Buckeye Partners, L.P.	ONEOK, Inc.
DCP Midstream Partners L.P.	Plains GP Holdings, L.P.
Enable Midstream Partners L.P.	Tallgrass Energy Partners, L.P.
EnLink Midstream Partners L.P.	Williams Companies, Inc.
Genesis Energy, L.P.	

This peer group is a subset of the Midstream Peer Group which has been adjusted for size by a regression analysis, except that the LTIP Peer Group is restricted to companies closer to the size of the Company for the 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.

Performance / Retention Awards. In recognition of past performance and to enhance retention, on January 12, 2018, the Compensation Committee also awarded a special grant to Mr. Perkins. The special performance / retention award was granted in the form of restricted stock units that vest 50% on December 31, 2018 and 50% on December 31, 2019, subject to his continued employment through the applicable vesting date. Mr. Perkins is the only named executive officer who received a special performance / retention award, and he received 80,000 restricted stock units.

Other Compensation Matters

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 estimate and record an expense for each award of long-term equity incentive compensation over the vesting period of the award. Accounting rules also require us to record cash compensation as an expense at the time the obligation is accrued.

Clawback Policy. To date, we have not adopted a formal clawback policy to recoup incentive-based compensation upon the occurrence of a financial restatement, misconduct, or other specified events. However, awards granted pursuant to the Stock Incentive Plan are subject to any written clawback policies that the Company may choose to adopt. Furthermore, restricted stock, restricted stock unit and performance share unit agreements covering grants made to our named executive officers and other employees in 2011 and later years, as applicable, 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. The Stock Incentive Plan provides that awards granted thereunder are subject to any written clawback policies that the Company may adopt.

Securities Trading 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.

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 provide that our Chief Executive Officer should own common stock of the Company having a market value of five times base salary, the other named executive officers should own common stock of the Company having a market value of three times their respective base salaries, and our independent directors should own common stock of the Company having a market value of five times their respective annual cash retainers. The guidelines were established with advice from the Compensation Consultant.

The CEO and executive officers have five years from the adoption of the Stock Ownership Guidelines to meet the applicable ownership levels (or with respect to new executive officers, from such later date as they are appointed an executive officer). The directors have five years from the adoption of the guidelines to meet the applicable ownership levels (or with respect to new directors, from such later date as they are elected a director). 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.

Tax Considerations. With respect to the 2017 year, Section 162(m) of the Internal Revenue Code (“Section 162(m)”) generally limited the deductibility by a corporation of compensation in excess of $1,000,000 paid to certain executive officers for services provided to that corporation. Due to the fact that our applicable 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).

Compensation Risk Assessment

The Compensation Committee reviews the relationship between our risk management policies and compensation policies and practices each year and, for 2017, 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 a combination of six or more 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 2017 with three-year vesting periods serves our executive compensation program’s goal of aligning the interests of executives and shareholders, thereby reducing the incentives to unnecessary risk-taking.

COMPENSATION COMMITTEE REPORT

Messrs. Davis, Crisp and Evans are the current members of our Compensation Committee In fulfilling its oversight responsibilities, the Compensation Committee 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, 2017 and in our proxy statement. Based on these reviews and discussions, the Compensation Committee recommended to our

Board of Directors that the Compensation Discussion and Analysis be included in our Annual Report on Form 10-K for the year ended December 31, 2017 and in our proxy statement 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 Compensation Committee

Waters S. Davis, IV,	Charles R. Crisp,	Robert B. Evans
Chairman	Committee Member	Committee Member

EXECUTIVE COMPENSATION

Summary Compensation Table for 2017

The following Summary Compensation Table sets forth the compensation of our named executive officers for 2017, 2016 and 2015. 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	2017	$ 745,833	$ -	$ 4,552,878	$ 23,184	$ 5,321,895
Chief Executive Officer	2016	-	453,125	3,534,138	1,616	3,988,879
	2015	697,500	-	2,066,608	22,720	2,786,828
Matthew J. Meloy	2017	472,500	418,800	4,901,220	22,814	5,814,534
Executive Vice President	2016	450,000	258,750	909,856	22,270	1,640,876
and Chief Financial Officer	2015	395,833	-	618,968	22,196	1,036,997
Patrick J. McDonie Executive Vice President - Southern Field Gathering and Processing	2017	422,633	221,000	3,977,300	22,685	4,643,618
Robert M. Muraro Executive Vice President - Commercial	2017	331,667	168,000	6,037,998	22,234	6,559,899
D. Scott Pryor Executive Vice President - Logistics and Marketing	2017	419,167	221,000	3,969,916	22,630	4,632,713

(1) For 2017, amounts reported in the "Bonus" column represents the portion of the bonus awarded pursuant to our 2017 Bonus Plan that was paid to the named executive officers in cash. The Compensation Committee approved settlement of the 2017 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 corresponding to approximately 160% of his target bonus amounts under the 2017 Bonus Plan. The Compensation Committee also determined that approximately 50% of each other named executive officer's total bonus amount would be settled in the form of restricted stock unit awards, resulting in these officers receiving restricted stock unit awards corresponding to approximately 80% of their respective target bonus amounts under the 2017 Bonus Plan. 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. These awards were granted on January 17, 2018, and will therefore be reported as compensation in the Summary Compensation Table for 2018 in accordance with SEC rules. Please see "Compensation Discussion and Analysis—Components of Executive Compensation Program for

Fiscal 2017—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 represent the aggregate grant date fair value of restricted stock unit and performance share unit awards granted under our Stock Incentive Plan in 2017 (including restricted stock unit awards granted on February 28, 2017 in connection with the 50% portion of bonuses under the 2016 Bonus Plan that we granted in the form of restricted stock units) computed in accordance with FASB ASC Topic 718. Assumptions used in the calculation of these amounts are included in Note 25 — Compensation Plans to our “Consolidated Financial Statements” included in our Annual Report on Form 10-K for fiscal year 2017. Detailed information about the value attributable to specific awards is reported in the table under “—Grants of Plan-Based Awards for 2017” below. The grant date fair value of each restricted stock unit subject to the restricted stock unit awards granted on January 20, 2017, assuming vesting will occur, is $60.475. The grant date fair value of each performance share unit subject to the performance share unit awards granted on January 20, 2017, assuming vesting will occur, is $99.71, 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 20, 2017 for each named executive officer is as follows: Mr. Perkins—$3,891,869; Mr. Meloy—$1,540,601; Mr. McDonie —$1,407,578; Mr. Muraro —$1,133,906; and Mr. Pryor—$1,047,578. The grant date fair value of each restricted stock unit subject to the restricted stock unit awards granted on February 28, 2017, assuming vesting will occur, is $55.94. The grant date fair value of each restricted stock unit subject to the restricted stock unit awards granted on July 23, 2017, assuming vesting will occur, is $46.145. For 2016, the Compensation Committee provided that bonuses to our named executive officers under the 2016 Bonus Plan would be a combination of cash equal to 50% of each officer’s total bonus amount and restricted stock unit awards equal to each officer’s total bonus amount under the 2016 Bonus Plan. 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 February 28, 2017, they are reported as compensation in the Summary Compensation Table for 2017 in accordance with SEC rules.

(3) In support of the Company's succession planning and management development goals, on January 20, 2017, the Compensation Committee also awarded special retention awards to certain executive officers. The special retention awards were granted in the form of restricted stock units that vest 30%, 30% and 40% on the fourth, fifth and sixth anniversaries, respectively, of the date of grant of the awards, subject to continued employment. The following executive officers were granted restricted stock units as special retention awards under the Stock Incentive Plan in the following amounts: (i) 50,000 restricted stock units to Mr. Meloy, (ii) 45,000 restricted stock units to Mr. McDonie, (iii) 60,000 restricted stock units to Mr. Muraro and (iv) 45,000 restricted stock units to Mr. Pryor. On July 23, 2017, Mr. Muraro was granted a special incentive award consisting of 25,000 restricted stock units under the Stock Incentive Plan that vest in full on the third anniversary of the grant date, subject to his continued service or if, from the date of his retirement through the third anniversary of the grant date, he 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).

(4) For 2017, "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	$ 21,600	$ 1,584	$ 23,184
Matthew J. Meloy	21,600	1,214	22,814
Patrick J. McDonie	21,600	1,085	22,685
Robert M. Muraro	21,600	634	22,234
D. Scott Pryor	21,600	1,030	22,630

Grants of Plan-Based Awards for 2017

The following table and the footnotes thereto provide information regarding grants of plan-based equity awards made to the named executive officers during 2017:

		Estimated Future Payouts Under Performance Share Unit Awards				
Name	Grant Date	Threshold (#)	Target (#)	Maximum (#)	Stock Awards: Number of Shares of Stock or Units	Grant Date Fair Value of Equity Awards (5)
Mr. Perkins	01/20/17 (1)	12,871	25,742	64,355	25,742	$ 4,123,482
	02/28/17 (2)				7,676	429,395
Mr. Meloy	01/20/17 (1)	5,095	10,190	25,475	10,190	1,632,285
	01/20/17 (3)				50,000	3,023,750
	02/28/17 (2)				4,383	245,185
Mr. McDonie	01/20/17 (1)	3,465	6,929	17,323	6,929	1,109,922
	01/20/17 (3)				45,000	2,721,375
	02/28/17 (2)				2,610	146,003
Mr. Muraro	01/20/17 (1)	3,750	7,500	18,750	7,500	1,201,388
					60,000	3,628,500

	01/20/17 (3)					
	02/28/17 (2)				974	54,486
	07/23/17 (4)				25,000	1,153,625
Mr. Pryor	01/20/17 (1)	3,465	6,929	17,323	6,929	1,109,922
	01/20/17 (3)				45,000	2,721,375
	02/28/17 (2)				2,478	138,619

(1) The grants on January 20, 2017 are the annual long-term equity incentive awards for 2017 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 – Components of Executive Compensation Program for Fiscal 2017 – Equity Settled Performance Share Units.

(2) The grants on February 28, 2017 are restricted stock unit awards granted in lieu of a portion of cash payments under the 2016 Bonus Plan.

(3) The awards disclosed in this row reflect special retention awards granted on January 20, 2017 to Messrs. Meloy, McDonie, Muraro and Pryor.

(4) The award disclosed in this row reflects a special incentive award granted on July 23, 2017 to Mr. Muraro.

(5) The dollar amounts shown for the restricted stock unit awards granted on January 20, 2017 are determined by multiplying the shares reported in the table by $60.475, which is the grant date fair value of the awards computed in accordance with FASB ASC Topic 718. The dollar amounts shown for the special retention awards granted on January 20, 2017 are determined by multiplying the shares reported in the table by $60.475, which is the grant date fair value of the awards computed in accordance with FASB ASC Topic 718. The dollar amounts shown for the performance share unit awards granted on January 20, 2017 are determined by multiplying the shares reported in the table by $99.71, which is the grant date fair value of the awards computed in accordance with FASB ASC Topic 718. The dollar amounts shown for the restricted stock units granted on February 28, 2017 are determined by multiplying the shares reported in the table by $55.94, which is the grant date fair value of the awards computed in accordance with FASB ASC Topic 718. The dollar amount shown for the special incentive award granted on July 23, 2017 is determined by multiplying the shares reported in the table by $46.145, which is the grant date fair value of the awards computed in accordance with FASB ASC Topic 718.

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

A discussion of 2017 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 2017 restricted stock unit and performance share unit awards under our Stock Incentive Plan. Further discussion regarding restricted stock units granted in February 2017 in lieu of a portion of cash payments under our 2016 Bonus Plan are described in our proxy statement for our 2017 annual meeting of stockholders, filed with the Securities and Exchange Commission on March 29, 2017 (“2017 Proxy Statement”). In addition, a discussion of the conversion in 2016 of outstanding performance unit awards previously granted under the Partnership’s Long Term Incentive Plan into comparable awards under the Company’s Equity Compensation Plan is set forth in “Compensation Discussion and Analysis” under “Components of Executive Compensation Program for Fiscal 2016—Long-Term Equity Incentive Awards—Conversion of Outstanding Partnership Equity Awards in the Buy-In Transaction” in our 2017 Proxy Statement.

Outstanding Equity Awards at 2017 Fiscal Year-End

The following table and the footnotes related thereto provide information regarding equity-based awards outstanding as of December 31, 2017 for each of our named executive officers.

Name	Stock Awards 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	194,078	$ 9,397,257	32,178	$ 1,558,035
Matthew J. Meloy	121,314	5,874,024	12,738	616,750
Patrick J. McDonie	103,248	4,999,268	8,661	419,378
Robert M. Muraro	107,332	5,197,015	9,375	453,938
D. Scott Pryor	102,249	4,950,897	8,661	419,378

(1) Represents the following shares of restricted stock units under our Stock Incentive Plan and restricted stock units under our Equity Compensation Plan (which were formerly outstanding performance unit awards previously granted under the Partnership's Long Term Incentive Plan and converted into comparable awards related to Company common stock in connection with the 2016 Buy-In Transaction) held by our named executive officers:

	Joe Bob Perkins	Matthew J. Meloy	Patrick J. McDonie	Robert M. Muraro	D. Scott Pryor
June 26, 2014 Award (a)	-	-	1,356	-	-
June 28, 2014 Award (b)	-	-	1,812	-	-
January 15, 2015 Award (c)	9,912	2,969	-	-	-
January 21, 2015 Award (d)	19,944	5,973	-	-	-
August 5, 2015 Award (e)	-	-	3,000	990	2,810
August 5, 2015 Award (f)	-	-	6,367	2,089	5,964
January 19, 2016 Award (g)	102,484	35,299	26,546	-	29,927
February 29, 2016 Award (h)	28,320	12,500	9,628	-	9,141
March 2, 2016 Award (i)	-	-	-	5,209	-
August 1, 2016 Award (j)	-	-	-	5,570	-
January 20, 2017 Award (k)	25,742	10,190	6,929	7,500	6,929
January 20, 2017 Award (l)	-	50,000	45,000	60,000	45,000
February 28, 2017 Award (m)	7,676	4,383	2,610	974	2,478
July 23, 2017 Award (n)	-	-	-	25,000	-
Total	194,078	121,314	103,248	107,332	102,249

(a) The restricted stock units issued on March 1, 2015 as replacement awards for the original grant awarded on June 26, 2014 under the Atlas Energy LP benefit plan prior to the acquisition of Atlas by the Company are subject to the following vesting schedule: 100% of the restricted stock units vest on June 26, 2018, 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 performance period.
(b) The Partnership phantom units awarded March 1, 2015 as replacement awards for the original grant awarded on June 28, 2014 under the Atlas Pipeline Partners LP benefit plan prior to the acquisition of Atlas by the Company were subsequently converted to Company restricted stock units at a ratio of 1 to .62 and 100% of the restricted stock units vest on June 28, 2018, 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 performance period.
(c) The restricted stock units awarded January 15, 2015 are subject to the following vesting schedule: 100% of the restricted stock units vest on January 15, 2018, 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 performance period.
(d) The Partnership performance units awarded January 21, 2015 were converted to Company restricted stock units at a ratio of 1 to .62 and 100% of the restricted stock units vest on June 30, 2018, 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 performance period.
(e) The restricted stock units awarded on August 5, 2015 are subject to the following vesting schedule: 100% of the restricted stock units vest on August 5, 2018, 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 performance period.
(f) The Partnership performance units awarded on August 5, 2015 were converted to Company restricted stock units at a ratio of 1 to .62 and 100% of the restricted stock units vest on June 30, 2018, 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 performance period.
(g) The restricted stock units awarded January 19, 2016 are subject to the following vesting schedule: 100% of the restricted stock units vest on January 19, 2019, 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 performance period.
(h) The restricted stock units awarded February 29, 2016 in settlement of awards under the 2015 Bonus Plan are subject to the following vesting schedule: 100% of the restricted stock units vest on February 28, 2019, 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 performance period.
(i) The restricted stock units awarded March 2, 2016 in settlement of awards under the 2015 Bonus Plan are subject to the following vesting schedule: 100% of the restricted stock units vest on February 28, 2019, 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 performance period.
(j) The restricted stock units awarded August 1, 2016 are subject to the following vesting schedule: 100% of the restricted stock units vest on August 1, 2019, 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 performance period.
(k) 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 performance period.

(l) 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 performance period.

(m) 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 performance period.

(n) The restricted stock units awarded July 23, 2017 as a special incentive grant are subject to the following vesting schedule: 100% of the restricted stock units vest July 23, 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 performance 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 29, 2017 ($48.42), which was the last trading day of fiscal 2017. 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 20, 2017 Award	
	Awards Granted	(a) Adjusted for Performance Factor (TSR)
Joe Bob Perkins	25,742	32,178
Matthew J. Meloy	10,190	12,738
Patrick J. McDonie	6,929	8,661
Robert M. Muraro	7,500	9,375
D. Scott Pryor	6,929	8,661

(a) Reflects the target number of performance share units granted to the named executive officers on January 20, 2017 multiplied by a performance percentage of 125%, which in accordance with SEC rules is the next higher performance level under the award that exceeds 2017 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, 2019, 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 at the end of the performance period.

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 29, 2017 ($48.42), which was the last trading day of fiscal 2017. The amounts do not include any related dividends accrued with respect to the awards.

Option Exercises and Stock Vested in 2017

The following table provides the amount realized during 2017 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 2017 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	40,254	$2,004,457
Matthew J. Meloy	6,696	323,250
Patrick J. McDonie	11,029	524,385
Robert M. Muraro	3,266	149,993
D. Scott Pryor	5,053	230,994

(1) Computed: (i) 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 14, 2017 vesting

date ($57.95), the March 31, 2017 vesting date ($59.90), the June 26, 2017 vesting date ($43.10), the June 30, 2017 vesting date ($45.20),the July 16, 2017 vesting date ($45.74), the August 1, 2017 vesting date ($46.22), the September 30, 2017 vesting date ($47.30), the December 16, 2017 vesting date ($46.36) and the December 20, 2017 vesting date ($45.54) and does not include associated dividends accrued during the vesting period, (ii) with respect to the restricted stock units (former equity-settled performance unit awards) by multiplying the number of restricted stock units vesting by the closing price of a share of common stock on the February 18, 2017 vesting date ($58.69), the June 28, 2017 vesting date ($44.20), June 30, 2017 vesting date ($45.20), the July 10, 2017 vesting date ($43.84) and the December 16, 2017 vesting date ($46.36) and does not include associated distributions or 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, Stock Incentive Plan and Equity Compensation Plan upon certain specified termination of employment and/or a change in control events, in each case, had such event occurred on December 31, 2017. 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 2017 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	$ 12,109,986	$ 18,676,261	$ 1,208,645	$ 12,146,284
Matthew J. Meloy	7,073,283	10,108,192	361,975	7,084,154
Patrick J. McDonie	5,909,019	8,071,518	385,853	5,920,607
Robert M. Muraro	5,981,087	7,715,969	126,597	5,984,889
D. Scott Pryor	5,875,901	8,034,533	361,430	5,886,755

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 2017 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.

On December 3, 2015, the Company amended the Change in Control Program to exclude the direct or indirect purchase of the Partnership or the General Partner by the Company or any of its affiliates from the definition of "Change in Control." As a result, the consummation of the Buy-In Transaction did not constitute a Change in Control event for purposes of the Change in Control Program.

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, 2017.

Name	Qualifying Termination Following Change in Control (1)
Joe Bob Perkins	$ 6,566,275
Matthew J. Meloy	3,034,909
Patrick J. McDonie	2,162,498
Robert M. Muraro	1,734,883
D. Scott Pryor	2,158,633

(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, 2017 for each named executive officer and his eligible dependents in the following amounts: (a) Mr. Perkins – $41,275, (b) Mr. Meloy – $42,409, (c) Mr. McDonie – $58,748, (d) Mr. Muraro– $54,883, and (e) Mr. Pryor—$54,883.

Stock Incentive Plan

Our named executive officers held outstanding restricted stock awards and restricted stock units under our forms of restricted stock agreement and restricted stock unit agreement, as applicable (the "Stock Agreements"), and performance share units under our form of performance share unit agreement (the "Performance Agreement") and the Stock Incentive Plan as of December 31, 2017. 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 and restricted stock units granted to him under the Stock Agreements, and related dividends then credited to him, will fully vest on the date upon which such Change in Control occurs, and (b) the performance share units granted to him under the Performance Agreement and related dividends credited to him will vest based on a performance factor as of the date of the Change in Control determined by the Compensation Committee. The 2017 performance share units have four separate performance periods: (1) the 2017 calendar year; (2) the 2018 calendar year; (3) the 2019 calendar year; and (4) the entirety of the performance period between January 1, 2017 and December 31, 2019. 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.

Restricted stock, restricted stock units and performance share units granted to a named executive officer under the Stock Agreements and Performance Agreements, and related dividends then credited to him, will also fully vest if the named executive officer's employment is terminated by reason of death or a "Disability." If a named executive officer's employment with us is terminated for any reason other than death or Disability, then his unvested restricted stock, restricted stock units and performance share units are forfeited to us for no consideration, except that (other than with respect to retention grants for Messrs. Meloy, McDonie, Muraro and Pryor), if a named executive officer retires or otherwise has a voluntary resignation, his awards will continue to vest on the original vesting schedule if, from the date of his 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 and Stock 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 Buy-In Transaction did not trigger the accelerated vesting of any of our outstanding long-term equity incentive compensation awards under the Stock Incentive 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, 2017. The amounts reported below assume that the price per share of our common stock was $48.42, which was the closing price per share of our common stock on December 29, 2017 (the last trading day of fiscal 2017). No amounts are reported assuming retirement as of December 31, 2017, 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	$ 10,937,639	(1)	$ 10,937,639	(1)

Matthew J. Meloy	6,722,179	(2)	6,722,179	(2)
Patrick J. McDonie	5,534,755	(3)	5,534,755	(3)
Robert M. Muraro	5,858,291	(4)	5,858,291	(4)
D. Scott Pryor	5,525,325	(5)	5,525,325	(5)

(1) Of the amount reported under each of the “Change in Control” column and the “Termination for Death or Disability” column:

(a) $479,939 and $105,762, respectively, relate to the restricted stock units and related dividend rights granted on January 15, 2015, which are scheduled to vest January 15, 2018;

(b) $4,962,275, and $746,085, respectively, relate to the restricted stock units and related dividend rights granted on January 19, 2016, which are scheduled to vest January 19, 2019;

(c) $1,371,254 and $180,398, respectively, relate to the restricted stock units and related dividend rights granted on February 29, 2016, in settlement of awards under the 2015 Bonus Plan which are scheduled to vest February 28, 2019;

(d) $1,246,428 and $140,551, respectively, relate to restricted stock units and related dividend rights granted on January 20, 2017, which are scheduled to vest on January 20, 2020.

(e) $1,220,564 and $91,757, respectively, relate to performance share units and related dividend rights granted on January 20, 2017, which are scheduled to vest on December 31, 2019; and

(f) 371,672 and 20,955, respectively, relate to restricted stock units and related dividend rights granted on February 28, 2017, in partial settlement of awards under the 2016 Bonus Plan, which are scheduled to vest on February 28, 2020,

(2) Of the amount reported under each of the "Change in Control" column and the "Termination for Death or Disability" column:

(a) $143,759 and $31,678, respectively, relate to the restricted stock units and related dividend rights granted on January 15, 2015, which are scheduled to vest January 15, 2018;

(b) $1,709,178 and $256,977, respectively, relate to the restricted stock units and related dividend rights granted on January 19, 2016, which are scheduled to vest January 19, 2019;

(c) $605,250 and $79,625, respectively, relate to the restricted stock units and related dividend rights granted on February 29, 2016, in settlement of awards under the 2015 Bonus Plan, which are scheduled to vest February 28, 2019;

(d) $493,400 and $55,637, respectively, relate to restricted stock units and related dividend rights granted on January 20, 2017, which are scheduled to vest on January 20, 2020

(e) $483,162 and $36,322, respectively, relate to performance share units and related dividend rights granted on January 20, 2017, which are scheduled to vest on December 31, 2019;

(f) $2,421,000 and $182,000 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: and

(g) $212,225 and $11,966, respectively, relate to restricted stock units and related dividend rights granted on February 28, 2017, in partial settlement of awards under the 2016 Bonus Plan, which are scheduled to vest on February 28, 2020,

(3) Of the amount reported under each of the "Change in Control" column and the "Termination for Death or Disability" column:

(a) $65,658 relates to restricted stock units issued on March 1, 2015 as replacement awards for the original grant awarded on June 26, 2014 under the Atlas Energy LP benefit plan prior to the acquisition of Atlas by the Company and which restricted stock units are scheduled to vest on June 26, 2018. Under the terms of the former Atlas plan dividend rights are earned and paid quarterly during the award vesting period.

(b) $87,737 relates to Partnership performance units awarded March 1, 2015 as replacement awards for the original grant awarded on June 28, 2014 under the Atlas Pipeline Partners LP benefit plan prior to the acquisition of Atlas by the Company. These performance units were subsequently converted at a ratio of 1 to .62 to restricted stock units which are scheduled to vest on June 28, 2018, under the terms of the former Atlas plan dividend rights are earned and paid quarterly during the award vesting period.

(c) $145,260 and $27,195, respectively, relate to the restricted stock units and related dividend rights granted on August 5, 2015, which are scheduled to vest August 5, 2018;

(d) $1,285,357 and $193,255, respectively, relate to the restricted stock units and related dividend rights granted on January 19, 2016, which are scheduled to vest January 19, 2019;

(e) $466,188 and $61,330, respectively, relate to the restricted stock units and related dividend rights granted on February 29, 2016, in settlement of awards under the 2015 Bonus Plan, which are scheduled to vest February 28, 2019;

(f) $335,502 and $37,832, respectively, relate to restricted stock units and related dividend rights granted on January 20, 2017, which are scheduled to vest on January 20, 2020;

(g) $328,541 and $24,698, respectively, relate to performance share units and related dividend rights granted on January 20, 2017, which are scheduled to vest on December 31, 2019;

(h) $2,178,900 and $163,800 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; and

(i) $126,376 and $7,125, respectively, relate to restricted stock units and related dividend rights granted on February 28, 2017, in partial settlement of awards under the 2016 Bonus Plan, which are scheduled to vest on February 28, 2020.

(4) Of the amount reported under each of the “Change in Control” column and the “Termination for Death or Disability” column:

(a) $47,936 and $8,975, respectively, relate to the restricted stock units and related dividend rights granted on August 5, 2015, which are scheduled to vest August 5, 2018;

(b) $252,220 and $33,181, respectively, relate to the restricted stock units and related dividend rights granted on March 2, 2016, in settlement of awards under the 2015 Bonus Plan, which are scheduled to vest February 28, 2019;

(c) $269,699 and $30,412, respectively, relate to the restricted stock units and related dividend rights granted on August 1, 2016, which are scheduled to vest August 1, 2018;

(d) $363,150 and $40,950, respectively, relate to restricted stock units and related dividend rights granted on January 20, 2017, which are scheduled to vest on January 20, 2020;

(e) $355,615 and $26,734, respectively, relate to performance share units and related dividend rights granted on January 20, 2017, which are scheduled to vest on December 31, 2019;

(f) $2,905,200 and $218,400 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;

(g) $47,161 and $2,659, respectively, relate to restricted stock units and related dividend rights granted on February 28, 2017, in partial settlement of awards under the 2016 Bonus Plan, which are scheduled to vest on February 28, 2020; and

(h) $1,210,500 and $45,500, respectively, relates to restricted stock units awarded July 23, 2017 as a special incentive grant which is scheduled to vest July 23, 2020, contingent upon continuous employment.

(5) Of the amount reported under each of the “Change in Control” column and the “Termination for Death or Disability” column:

(a) $136,060 and $25,473, respectively, relate to the restricted stock units and related dividend rights granted on August 5, 2015, which are scheduled to vest August 5, 2018;

(b) $1,449,065 and $217,869, respectively, relate to the restricted stock units and related dividend rights granted on January 19, 2016, which are scheduled to vest January 19, 2019;

(c) $442,607 and $58,228, respectively, relate to the restricted stock units and related dividend rights granted on February 29, 2016, in settlement of awards under the 2015 Bonus Plan, which are scheduled to vest February 28, 2019;

(d) $335,502 and $37,832, respectively, relate to restricted stock units and related dividend rights granted on January 20, 2017, which are scheduled to vest on January 20, 2020

(e) $328,541 and $24,698, respectively, relate to performance share units and related dividend rights granted on January 20, 2017, which are scheduled to vest on December 31, 2019;

(f) $2,178,900 and $163,000 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: and

(g) $119,985 and $6,765, respectively, relate to restricted stock units and related dividend rights granted on February 28, 2017, in partial settlement of awards under the 2016 Bonus Plan, which are scheduled to vest on February 28, 2020.

Equity Compensation Plan

The Buy-In Transaction did not trigger the accelerated vesting of any outstanding long-term equity incentive compensation awards under the Equity Compensation Plan (formerly, the Partnership's Long-Term Incentive Plan). Upon completion of the Buy-In Transaction, all outstanding performance unit awards previously granted under the Partnership's Long-Term Incentive Plan (which was assumed by the Company in connection with the Buy-In Transaction and renamed the Equity Compensation Plan), were converted and restated into comparable awards based on the Company's common shares. Specifically, each outstanding performance unit award was converted and restated, effective as of the effective time of the Buy-In Transaction, into an award to acquire, pursuant to the same time-based vesting schedule and forfeiture and termination provisions, a comparable number of Company common shares determined by multiplying the number of performance units subject to each award by the exchange ratio in the Buy-In Transaction (0.62), rounded down to the nearest whole share, and eliminating the performance factor that was based on the Partnership's common units. All amounts previously credited as distribution equivalent rights under any outstanding performance unit award continue to remain so credited and will be payable on the payment date set forth in the applicable award agreement, subject to the same time-based vesting schedule previously included in the performance unit award, but without application of any performance factor.

As a result, each of our named executive officers held outstanding restricted stock units under our Equity Compensation Plan (which were formerly outstanding performance unit awards previously granted under the Partnership's Long Term Incentive Plan and converted into comparable awards related to Company stock in connection with the Buy-In Transaction) under the Company's form of agreement (the "Share Grant Agreement") and the Equity Compensation Plan as of December 31, 2017.

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, the restricted stock units subject to the Share Grant Agreements, and related dividends or distributions then credited to him, will fully vest on the date upon which such Change in Control occurs.

Generally, restricted stock units and the related dividend or distribution equivalent rights subject to a Share Grant Agreement would be automatically forfeited without payment upon the termination of the named executive officer's employment with us and our affiliates. However, if a named executive officer's employment was terminated by reason of his death or "Disability" or was terminated by us other than for "Cause," or if the executive retired and he 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 end of the vesting period, he would become vested in the restricted stock units that he is otherwise qualified to receive as if the named executive officer had remained continuously employed through the end of the performance period. The named executive officer will also receive a cash payment in the amount of the dividend or distribution equivalent rights that would have accrued through the end of the vesting period.

The following terms generally have the meanings specified below for purposes of the Equity Compensation Plan:

Change in Control means (i) any person or group, other than an affiliate, becomes the beneficial owner, by way of merger, consolidation, recapitalization, reorganization or otherwise, of 50% or more of the combined voting power of the equity interests in the Company, (ii) the stockholders of the Company approve a plan of complete liquidation of the Company or (iii) the sale or other disposition by the Company of all or substantially all of its assets in one or more transactions to any person other than one of the Company's affiliates.

Cause means (i) failure to perform assigned duties and responsibilities, (ii) engaging in conduct which is injurious (monetarily or otherwise) to us or our affiliates, (iii) breach of any corporate policy or code of conduct established by us or our affiliates, or breach of any agreement between the named executive officer and us or our affiliates, or (iv) conviction of a misdemeanor involving moral turpitude or a felony. If the named executive officer is a party to an agreement with us or our affiliates in which this term is defined, then that definition will apply for purposes of the Equity Compensation Plan and the Share Grant Agreement.

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 Equity Compensation Plan and related Stock Grant Agreements in the event there was a Change in Control or their employment was terminated due to death or Disability or by us without Cause, each as of December 31, 2017. No amounts are reported assuming retirement as of December 31, 2017, since additional conditions must be met following a named executive officer's retirement in order for any performance share awards to become vested. The amounts reported below assume that the price per share of the Company's stock was $48.42, which was the closing price per share of stock on December 29, 2017 (the last trading day of fiscal 2017).

Name	Change in Control		Termination for Death or Disability or Without Cause	
Joe Bob Perkins	$ 1,172,347	(1)	$ 1,208,645	(1)
Matthew J. Meloy	351,105	(2)	361,975	(2)
Patrick J. McDonie	374,265	(3)	385,853	(3)
Robert M. Muraro	122,795	(4)	126,597	(4)
D. Scott Pryor	350,575	(5)	361,430	(5)

(1) Of the amount reported under the "Change in Control" column: $965,688 and $206,659, respectively, relate to the performance shares and related dividend and distribution equivalent rights granted on January 21, 2015. Of the amount reported under the "Termination for Death or Disability or Without Cause" column: $965,688 and $242,957, respectively, relate to the performance shares and related dividend and distribution equivalent rights granted on January 21, 2015.

(2) Of the amount reported under the "Change in Control" column: $289,213 and $61,892, respectively, relate to the performance shares and related dividend and distribution equivalent rights granted on January 21, 2015. Of the amount reported under the "Termination for Death or Disability or Without Cause" column: $289,213 and $72,762, respectively, relate to the performance shares and related dividend and distribution equivalent rights granted on January 21, 2015.

(3) Of the amount reported under the "Change in Control" column: $308,290 and $65,975, respectively, relate to the performance shares and related dividend and distribution equivalent rights granted on August 5, 2015. Of the amount reported under the "Termination for Death or Disability or Without Cause" column: $308,290 and $77,563, respectively, relate to the performance shares and related dividend and distribution equivalent rights granted on August 5, 2015.

(4) Of the amount reported under the "Change in Control" column: $101,149 and $21,646, respectively, relate to the performance shares and related dividend and distribution equivalent rights granted on August 5, 2015. Of the amount reported under the "Termination for Death or Disability or Without Cause" column: $101,149 and $25,448, respectively, relate to the performance shares and related dividend and distribution equivalent rights granted on August 5, 2015.

(5)

Of the amount reported under the “Change in Control” column: $288,777 and $61,798, respectively, relate to the performance shares and related dividend and distribution equivalent rights granted on August 5, 2015. Of the amount reported under the “Termination for Death or Disability or Without Cause” column: $288,777 and $72,653, respectively, relate to the performance shares and related dividend and distribution equivalent rights granted on August 5, 2015.

Director Compensation

The following table sets forth the compensation earned by our non-employee directors for 2017:

Name	Fees Earned or Paid in Cash	Stock Awards (2)	Total Compensation
Charles R. Crisp	$ 131,000	$ 119,378	$ 250,378
Ershel C. Redd Jr.	100,000	119,378	219,378
Chris Tong	123,000	119,378	242,378
Laura C. Fulton	100,000	119,378	219,378
Waters S. Davis, IV	121,000	119,378	240,378
Rene R. Joyce	94,000	119,378	213,378
Robert B. Evans	103,000	119,378	222,378

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(1) Amounts reported in the "Stock Awards" column represent the aggregate grant date fair value of fully vested shares of our common stock awarded to the non-employee directors under our Stock Incentive Plan, computed in accordance with FASB ASC Topic 718. 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 23 – Stock and Other Compensation Plans included in our Annual Report on Form 10-K for the year ended December 31, 2017. On January 20, 2017, each director serving at that time received 1,974 fully vested shares of our common stock in connection with their 2017 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 $60.475. As of December 31, 2017, none of our non-employee directors held any outstanding stock options or any outstanding, unvested shares of our common stock.

Narrative to Director Compensation Table

For 2017, all non-employee directors received an annual cash retainer of $76,000. The lead director received an additional annual retainer of $15,000, the Chairman of the Audit Committee 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 received an additional retainer of $10,000. All of our non-employee directors receive $1,500 for each Board of Directors, Audit Committee, Compensation Committee and Nominating and Governance Committee meeting attended. Meeting fees may also be paid for certain other informational or review sessions that non-employee directors attended. Payment of non-employee director fees is generally made twice annually, at the second regularly scheduled meeting of the Board of Directors and at the final regularly scheduled meeting of the Board of Directors for the fiscal year. 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, Perkins and Heim have been omitted from the table. Because Mr. Perkins is a named executive officer for 2017, 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, and Mr. Heim, who serves as Vice Chairman of the Board, are executive officers who do not receive any additional compensation for services provided as a director. Due to the fact that Messrs. Whalen and Heim are not named executive officers, their 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 2017 to our non-employee directors under the Stock Incentive Plan. Each of these directors received an award of 1,974 fully vested shares of our common stock, which reflected our intent to provide them with a target value of approximately $115,000 in annual long-term incentive awards, which was an increase over the target value for 2016 of $100,000. The awards are intended to align the long-term interests of our directors with those of our shareholders.

Changes for 2018

Director Long-term Equity Incentives. In January 2018, each of our non-employee directors received an award of 2,312 restricted shares of our common stock under the Stock Incentive Plan with a one year vesting period, which reflects our desire to maintain the target value of the annual awards of approximately $115,000 per year and impose new vesting requirements on director equity incentives.

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 2017, our last completed fiscal year:

- The median of the annual total compensation of all employees of our company (other than the CEO) was $103,207 and
- The annual total compensation of Mr. Perkins, as reported in the Summary Compensation Table included elsewhere within this Proxy Statement, was $5,321,895.
- Based on this information, for 2017 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 52 to 1.

To calculate the CEO Pay Ratio we must identity 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 October 31, 2017, our employee population consisted of approximately 2070 individuals. This population consisted of our full-time and part-time employees, as we do not have temporary or seasonal workers. We selected October 31, 2017 as our identification date for determining our median employee because it enabled us to make such identification in a reasonably efficient and economic manner.
- 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 178. 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, 2017 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.

After we identified our median employee, we combined all of the elements of such employee's compensation for the 2017 year in accordance with the requirements of Item 402(c)(2)(x) of Regulation S-K, resulting in annual total compensation of $103,207. With respect to the annual total compensation of our CEO, we used the amount reported in the "Total" column of our 2017 Summary Compensation Table included in this Proxy Statement and incorporated by reference under Item 11 of Part III of our Annual Report.

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

The following table sets forth information regarding the beneficial ownership of our common stock as of February 1, 2018 (unless otherwise indicated) held by:

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

TRC owns all of the outstanding Partnership common units of the Partnership. As of February 1, 2018, none of our directors or executive officers owned any Preferred Shares or Preferred Units of the Partnership.

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 218,830,282 shares of our common stock outstanding on February 1, 2018.

	Targa Resources Corp.	
Name of Beneficial Owner (1)	Common Stock Beneficially Owned	Percentage of Common Stock Beneficially

		Owned
BlackRock, Inc. (2)	12,035,357	5.5%
Joe Bob Perkins (3)	505,917	*
Matthew J. Meloy	43,087	*
Patrick J. McDonie	38,719	*
Robert Muraro	2,672	*
D. Scott Pryor	10,810	*
Rene R. Joyce (4)	1,057,707	*
James W. Whalen (5)	623,642	*
Michael A. Heim (6)	424,640	*
Charles R. Crisp	122,893	*
Chris Tong (7)	85,549	*
Robert B. Evans	28,606	*
Ershel C. Redd Jr.	14,482	*
Laura C. Fulton	9,515	*
Waters S. Davis, IV	6,799	*
All directors and executive officers as a group (19 persons)	3,842,955	1.76%

*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, 2017 and filed with the SEC on February 8, 2018, the business address for BlackRock, Inc. is 55 East 52nd Street New York, NY 10055.

(3) Shares of common stock beneficially owned by Mr. Perkins include: (i) 207,370 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.

(4) 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.

(5) Shares of common stock beneficially owned by Mr. Whalen include (i) 345,999 shares issued to the Whalen Family Investments Limited Partnership and (ii) 98,000 issued to the Whalen Family Investments Limited Partnership 2.

(6) Shares of common stock beneficially owned by Mr. Heim include: (i) 124,878 shares issued to The Michael Heim 2009 Family Trust, of which Mr. Heim and his son are co-trustees and have shared voting and investment power; (ii) 81,672 shares issued to The Patricia Heim 2009 Grantor Retained Annuity Trust, of which Mr. Heim and his wife are co-trustees and have shared voting and investment power; (iii) 57,973 shares issued to the Pat Heim 2012 Family Trust, of which Mr. Heim's wife and son serve as co-trustees and have shared voting and investment power; (iv) 38,400 shares issued to the Heim 2012 Children's Trust, of which Mr. Heim serves as trustee; and (v) 19,472 shares held by Mr. Heim's wife.

(7) Shares of common stock beneficially owned by Mr. Tong include 1,310 shares held by Mr. Tong's wife.

Securities Authorized for Issuance under Equity Compensation Plans

The following table sets forth certain information as of December 31, 2017 regarding our long-term incentive plans, under which our common stock is authorized for issuance to employees, consultants and directors of us, the general partner and their affiliates. Our sole equity compensation plan, under which we will make equity grants in the future, is our Amended and Restated 2010 Stock Incentive Plan, which was approved by our 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)
	-	-	9,961,050

Equity compensation plans approved by security holders (1)

(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 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 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.

Our Relationship with Targa Resources Partners LP and its General Partner

Our only cash generating assets consist of our interests in the Partnership, which consist of (i) a 2.0% general partner interest in the Partnership and (ii) all of the outstanding common units of the Partnership.

Reimbursement of Operating and General and Administrative Expense

Under the terms of the Partnership Agreement, the Partnership reimburses us for all direct and indirect expenses, as well as expenses otherwise allocable to the Partnership in connection with the operation of the Partnership's business, incurred on the Partnership's behalf, which includes 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 the Partnership's benefit. We perform centralized corporate functions for the Partnership, such as legal, accounting, treasury, insurance, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes, engineering and marketing. The general partner determines the amount of general and administrative expenses to be allocated to the Partnership in accordance with the Partnership Agreement. Other than our direct costs of being a reporting company, so long as our only cash-generating asset consists of our interests in the Partnership, substantially all of our general and administrative costs have been and will continue to be allocated to the Partnership.

Competition

We are not restricted, under the Partnership's partnership agreement, from competing with the Partnership. We may acquire, construct or dispose of additional midstream energy or other assets in the future without any obligation to offer the Partnership the opportunity to purchase or construct those assets.

Contracts with Affiliates

Indemnification Agreements with Directors and Officers

The Partnership and the general partner have entered into indemnification agreements with each individual who was an independent director of the general partner prior to the TRC/TRP Merger. Each indemnification agreement provides that each of the Partnership and the general partner 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 the Partnership or the general partner is jointly liable in the proceeding with the indemnitee, the Partnership and the general partner will contribute funds to the indemnitee for his Expenses (as defined in the Indemnification Agreement) in proportion to relative benefit and fault of the Partnership or the general partner on the one hand and indemnitee on the other in the transaction giving rise to the proceeding.

Each indemnification agreement also provides that the Partnership and the general partner will indemnify and hold harmless the indemnitee against Expenses incurred for actions taken as a director or officer of the Partnership or the general partner or for serving at the request of the Partnership or the general partner 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. The indemnification agreement also provides that the Partnership and the general partner 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.

We have entered into parent indemnification agreements with each of our directors and officers, including directors and officers who serve or served as directors and/or officers of the general partner. Each parent indemnification agreement provides that we will indemnify and hold harmless each indemnitee for Expenses (as defined in the parent indemnification agreement) 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 indemnitee. If such indemnification is unavailable as a result of a court decision and if we and the indemnitee are jointly liable in the proceeding, we will contribute funds to the indemnitee for his Expenses in proportion to relative benefit and fault of us and indemnitee in the transaction giving rise to the proceeding.

Each parent indemnification agreement also provides that we will indemnify the indemnitee for monetary damages for actions taken as our director or officer or for serving at our request as a director or officer or another position at another corporation or enterprise, as the case may be but only if (i) the indemnitee acted in good faith and, in the case of conduct in his official capacity, in a manner he reasonably believed to be in our best interests and, in all other cases, not opposed to our best interests and (ii) in the case of a criminal proceeding, the indemnitee must have had no reasonable cause to believe that his conduct was unlawful. The parent indemnification agreement also provides that we 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.

Transactions with Related Persons

Relationship with Sajet Resources LLC

In December 2010, prior to our initial public offering, Sajet Resources LLC ("Sajet"), was spun-off from Targa. Rene Joyce and James Whalen, directors of Targa, are also directors of Sajet. Joe Bob Perkins, James Whalen, Michael Heim, Jeffrey McParland, Paul Chung, and Matthew Meloy, executive officers of Targa, are also executive officers of Sajet. Sajet owns certain technology rights, real property and ownership interests in Allied CNG Ventures LLC. We provide general and administrative services to Sajet and are reimbursed for these amounts at our actual cost. Services provided to Sajet totaled $0.3 million in 2017.

Relationship with Tesla Resources LLC

In September 2012, Tesla Resources LLC ("Tesla") was spun-off from Sajet. Tesla has ownership interests in Floridian Natural Gas Storage Company LLC ("Floridian"). Rene Joyce and James Whalen, directors of Targa, are also directors of Tesla and managers of Floridian. Joe Bob Perkins, James Whalen, Michael Heim, Jeffrey McParland, Paul Chung, and Matthew Meloy, executive officers of Targa, are also executive officers of Tesla. We provide general and administrative services to Tesla and Floridian and are reimbursed for these amounts at our actual cost. Services provided to Tesla and Floridian totaled $0.1 million in 2017.

Relationship with Apache Corp.

Rene Joyce, a director of Targa and of the Partnership's general partner, is also a director of Apache Corporation ("Apache"), since May 2017, with whom we purchase and sell natural gas and NGLs. During 2017, we made sales to Apache of $1.0 million and purchases of $79.5 million from Apache.

Relationship with Total Safety US Inc.

Joe Bob Perkins, Chief Executive Officer and a director of Targa and of the Partnership's general partner, was also a member of the Board of Managers of W3 Holdings, LLC, parent company of Total Safety US Inc. ("Total Safety"), until March 2017, which provides us safety services and equipment, including detection and monitoring systems. During 2017, we made payments of $0.6 million to Total Safety.

Relationship with Kansas Gas Service

Robert Evans, a director of Targa and of the Partnership's 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 2017, we transacted sales of $33.8 million with Kansas Gas.

Relationships with Southern Company Gas, EOG Resources Inc., and IntercontinentalExchange, Inc.

Charles R. Crisp, a director of the Company and of the Partnership's 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. The following table shows our transactions with each of these entities during 2017:

Entity	Sales	Purchases
	(in millions)	
Sequent	$ 109.9	$ 14.7
NICOR	21.2	—
MS Power	—	0.4
EOG	14.7	14.5
ICE Group	—	0.5

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

Relationships with Martin Gas Sales and Southwest Energy LP

Ershel C. Redd, a director of Targa and of the Partnership's general partner, has an immediate family member who was an officer of Martin Gas Sales, which is a subsidiary of Martin Midstream Partners LP ("Martin"), until March 2017, and 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. The following table shows our transactions with each of these entities during 2017:

Entity	Sales	Purchases
	(in millions)	
Martin Gas	$ 4.5	$ 0.9
Southwest Energy	3.3	2.7

Relationship with Intercontinental Exchange, Inc.

Jennifer Kneale, who will become an executive officer of Targa and of the Partnership's general partner, effective March 1, 2018, has an immediate family member who is an officer of ICE Group. During 2017, we had purchases of $0.5 million from ICE Group.

Conflicts of Interest

Conflicts of interest exist and may arise in the future as a result of the relationships between the general partner and its affiliates (including us), on the one hand, and the Partnership and its other limited partners, on the other hand. The directors and officers of the general partner have fiduciary duties to manage the general partner and us, if applicable, in a manner beneficial to our owners. At the same time, the general partner has a fiduciary duty to manage the Partnership in a manner beneficial to it and its unitholders. Please see "—Review, Approval or Ratification of Transactions with Related Persons" below for additional detail of how these conflicts of interest will be resolved.

Review, Approval or Ratification of Transactions with Related Persons

Our policies and procedures for approval or ratification of transactions with "related persons" are not contained in a single policy or procedure. Instead, they are reflected in the general operation of our board of directors, consistent with past practice. We distribute and review a questionnaire to our executive officers and directors requesting information regarding, among other things, certain transactions with us in which they or their family members have an interest. Pursuant to our Code of Conduct, our officers and directors are required to abandon or forfeit any activity or interest that creates a conflict of interest between them and us or any of our subsidiaries, unless the conflict is pre-approved by our board of directors.

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

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

•

approved by the general partner's conflicts committee, although the general partner is not obligated to seek such approval;

- approved by the vote of a majority of the Partnership's outstanding common units, excluding any common units owned by the general partner or any of its affiliates;
- on terms no less favorable to the Partnership than those generally being provided to or available from unrelated third parties; or
- fair and reasonable to the Partnership, taking into account the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to the Partnership.

The general partner may, but is not required to, seek the approval of such resolution from the conflicts committee of its board of directors. If the 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 the partnership agreement, the general partner or its conflicts committee may consider any factors they determine in good faith to consider when resolving a conflict. When the 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.

Director Independence

Messrs. Crisp, Redd, Tong, Evans, and Davis and Ms. Fulton are our independent directors under the NYSE's listing standards. Please see "Item 10. Directors, Executive Officers and Corporate Governance." Our board of directors examined the commercial relationships between us and companies for whom our independent directors serve as directors or with whom family members of our independent directors have an employment relationship. The commercial relationships reviewed consisted of product and services purchases and product sales at market prices consistent with similar arrangements with unrelated entities.

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 for independent auditing, tax and related services for each of the last two fiscal years:

	2017	2016
	(In millions)	
Audit fees (1)	$5.1	$5.5
Audit-related fees (2)	—	—
Tax fees (3)	—	0.5
All other fees (4)	0.6	0.4
	$5.7	$6.4

(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.

The Audit Committee has approved the use of PricewaterhouseCoopers LLP as our independent principal accountant. All services provided by our independent principal accountant are subject to pre-approval by the Audit Committee. The Audit Committee is informed of each engagement of the independent principal accountant to provide services to us.

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***	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 Corp.'s Current Report on Form 8-K filed October 20, 2014 (File No. 001-34991)).
2.8***	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 Corp.'s Current Report on Form 8-K filed October 20, 2014 (File No. 001-34991)).
2.9***	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 Corp.'s Current Report on Form 8-K filed November 6, 2015 (File No. 001-34991)).
2.10***	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 Corp.'s Current Report on Form 8-K filed January 23, 2017 (File No. 001-34991)).
2.11***	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 Corp.'s Current Report on Form 8-K filed January 23, 2017 (File No. 001-34991)).
2.12***	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 Corp.'s Current Report on Form 8-K filed January 23, 2017 (File No. 001-34991)).
3.1	Amended and Restated Certificate of Incorporation of Targa Resources

	Corp. (incorporated by reference to Exhibit 3.1 to Targa Resources Corp.'s Current Report on Form 8-K filed December 16, 2010 (File No. 001-34991)).
3.2	Certificate of Designations of Series A Preferred Stock of Targa Resources Corp., filed with the Secretary of State of the State of Delaware on March 16, 2016 (incorporated by reference to Exhibit 3.1 to Targa Resources Corp.'s Current Report on Form 8-K/A filed March 17, 2016 (File No. 001-34991)).

Number	Description
3.3	Amended and Restated Bylaws of Targa Resources Corp. (incorporated by reference to Exhibit 3.2 to Targa Resources Corp.'s Current Report on Form 8-K filed December 16, 2010 (File No. 001-34991)).
3.4	First Amendment to the Amended and Restated Bylaws of Targa Resources Corp. (incorporated by reference to Exhibit 3.1 to Targa Resources Corp.'s Current Report on Form 8-K filed January 15, 2016 (File No. 001-34991)).
3.5	Certificate of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.2 to Targa Resources Partners LP's Registration Statement on Form S-1 filed November 16, 2006 (File No. 333-138747)).
3.6	Certificate of Formation of Targa Resources GP LLC (incorporated by reference to Exhibit 3.3 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed January 19, 2007 (File No. 333-138747)).
3.7	Third Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP, effective December 1, 2016 (incorporated by reference to Exhibit 3.1 to Targa Resources Partners LP's Current Report on Form 8-K filed October 21, 2016 (File No. 001-33303)).
3.8	Amendment No. 1 to the Third Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.1 to Targa Resources Partners LP's Current Report on

Form 8-K (File No. 001-33303) filed December 12, 2017).

3.9 Limited Liability Company Agreement of Targa Resources GP LLC (incorporated by reference to Exhibit 3.4 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed January 19, 2007 (File No. 333-138747)).

4.1 Specimen Common Stock Certificate (incorporated by reference to Exhibit 4.1 to Targa Resources Corp.'s Registration Statement on Form S-1/A filed November 12, 2010 (File No. 333-169277)).

4.2 Registration Rights Agreement, dated March 16, 2016, by and among Targa Resources Corp. and the purchasers named on Schedule A thereto (incorporated by reference to Exhibit 4.1 to Targa Resources Corp.'s Current Report on Form 8-K/A filed March 17, 2016 (File No. 001-34991)).

4.3 Amendment No. 1 to the Registration Rights Agreement dated March 16, 2016, dated September 13, 2016, among Targa Resources Corp. and Stonepeak Target Holdings, LP and Stonepeak Target Upper Holdings LLC (incorporated by reference to Exhibit 4.3 to Targa Resources Corp.'s Quarterly Report on Form 10-Q filed November 4, 2016 (File No. 001-34991)).

4.4 Registration Rights Agreement, dated March 16, 2016, by and among Targa Resources Corp. and the purchasers named on Schedule A thereto (incorporated by reference to Exhibit 4.2 to Targa Resources Corp.'s Current Report on Form 8-K/A filed March 17, 2016 (File No. 001-34991)).

4.5

	Amendment No. 1 to the Registration Rights Agreement dated March 16, 2016, dated September 13, 2016, among Targa Resources Corp. and Stonepeak Target Holdings, LP and Stonepeak Target Upper Holdings LLC (incorporated by reference to Exhibit 4.2 to Targa Resources Corp.'s Quarterly Report on Form 10-Q filed November 4, 2016 (File No. 001-34991)).
4.6	Board Representation and Observation Rights Agreement, dated as of March 16, 2016, by and between Targa Resources Corp. and Stonepeak Target Holdings LP (incorporated by reference to Exhibit 4.3 to Targa Resources Corp.'s Current Report on Form 8-K/A filed March 17, 2016 (File No. 001-34991)).
4.7	Warrant Agreement, dated as of March 16, 2016, by and among Targa Resources Corp., Computershare Inc. and Computershare Trust Company, N.A (incorporated by reference to Exhibit 4.4 to Targa Resources Corp.'s Current Report on Form 8-K/A filed March 17, 2016 (File No. 001-34991)).
10.1	Second Amendment and Restatement Agreement dated as of October 7, 2016, 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 Corp.'s Current Report on Form 8-K filed October 11, 2016 (File No. 001-34991)).
10.2	Targa Resources Investments Inc. Amended and Restated Stockholders' Agreement dated as of October 28, 2005 (incorporated by reference to Exhibit 10.2 to Targa Resources Inc.'s Registration Statement on Form S-4/A filed December 18, 2007 (File

No. 333-147066)).

Number	Description
10.3	First Amendment to Amended and Restated Stockholders' Agreement, dated January 26, 2006 (incorporated by reference to Exhibit 10.3 to Targa Resources Inc.'s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.4	Second Amendment to Amended and Restated Stockholders' Agreement, dated March 30, 2007 (incorporated by reference to Exhibit 10.4 to Targa Resources Inc.'s

	Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.5	Third Amendment to Amended and Restated Stockholders' Agreement, dated May 1, 2007 (incorporated by reference to Exhibit 10.5 to Targa Resources Inc.'s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.6	Fourth Amendment to Amended and Restated Stockholders' Agreement, dated December 7, 2007 (incorporated by

	reference to Exhibit 10.6 to Targa Resources Inc.'s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.7	Fifth Amendment to Amended and Restated Stockholders' Agreement, dated December 1, 2009 (incorporated by reference to Exhibit 10.1 to Targa Resources, Inc.'s Current Report on Form 8-K filed December 2, 2009 (File No. 333-147066)).
10.8	Form of Sixth Amendment to Amended and Restated

	Stockholders' Agreement (incorporated by reference to Exhibit 10.11 to Targa Resources Corp.'s Registration Statement on Form S-1/A filed November 12, 2010 (File No. 333-169277)).
10.9+	Targa Resources Corp. 2010 Stock Incentive Plan (incorporated by reference to Exhibit 4.4 of Targa Resources Corp's Registration Statement on Form S-8 filed December 9, 2010 (File No. 333-171082)).
10.10+	Amended and Restated Targa Resources Corp. 2010

	Stock Incentive Plan, as amended and restated effective May 22, 2017 (incorporated by reference to Exhibit 10.1 to Targa Resources Corp.'s Current Report on Form 8-K filed May 23, 2017 (File No. 001-34991)).
10.11+	Form of Restricted Stock Unit Agreement (incorporated by reference to Exhibit 10.1 to Targa Resources Corp.'s Current Report on Form 8-K filed July 18, 2013 (File No. 001-34991)).
10.12+	Form of Restricted Stock Agreement (incorporated by

	reference to Exhibit 10.2 to Targa Resources Corp.'s Current Report on Form 8-K filed July 18, 2013 (File No. 001-34991)).
10.13+*	Form of Restricted Stock Agreement for Directors, dated as of January 17, 2018.
10.14+	Targa Resources Corp. Equity Compensation Plan (f/k/a Targa Resources Partners Long-Term Incentive Plan), as amended and restated effective February 17, 2016 (incorporated by reference to Exhibit 10.1 to Targa Resources Corp.'s Quarterly

	Report on Form 10-Q filed May 10, 2016 (File No. 001-34991)).
10.15+	Targa Resources Corp. Long-Term Incentive Plan (f/k/a Targa Resources Investments Inc. Long-Term Incentive Plan), as amended and restated effective February 17, 2016 (incorporated by reference to Exhibit 10.2 to Targa Resources Corp.'s Quarterly Report on Form 10-Q filed May 10, 2016 (File No. 001-34991)).
10.16+	Form of Restricted Stock Agreement under Targa Resources

	Corp. 2010 Stock Incentive Plan (incorporated by reference to Exhibit 10.3 to Targa Resources Corp.'s Quarterly Report on Form 10-Q filed May 10, 2016 (File No. 001-34991)).
10.17+	Form of Performance Share Grant Agreement, as amended and restated effective February 17, 2016, under Targa Resources Corp. Equity Compensation Plan (incorporated by reference to Exhibit 10.4 to Targa Resources Corp.'s Quarterly Report on

	Form 10-Q filed May 10, 2016 (File No. 001-34991)).
10.18+	Form of Performance Share Grant Agreement, as amended and restated effective February 17, 2016, under Targa Resources Corp. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.5 to Targa Resources Corp.'s Quarterly Report on Form 10-Q filed May 10, 2016 (File No. 001-34991)).
10.19+*	Form of Performance Share Grant Agreement, dated as of January 20, 2017 under Targa Resources

Corp. 2010
Stock Incentive
Plan.

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Number	Description
10.20+	Targa Resources Corp. 2015 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 20, 2015 (File No. 001-33303)).
10.21+	Targa Resources Corp. 2016 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, 2016 (File No. 001-33303)).
10.22+	Targa Resources Corp. 2017 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 25, 2017 (File No. 001-33303)).
10.23+	Targa Resources Corp. 2018 Annual Incentive

	Compensation Plan (incorporated by reference to Exhibit 10.1 to Targa Resources Corp.'s Current Report on Form 8-K filed January 18, 2018 (File No. 001-34991)).
10.24+	Targa Resources Partners Long-Term Incentive Plan (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed February 1, 2007 (File No. 333-138747)).
10.25+	Form of Targa Resources Partners LP Restricted Unit Grant Agreement — 2010 (incorporated by reference to Exhibit 10.15 to Targa Resources Partners LP's Form 10-K filed March 4, 2010 (File No. 001-33303)).
10.26+	Targa Resources Partners LP Performance Unit Grant Agreement (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K/A filed

	July 24, 2013 (File No. 001-33303)).
10.27+	Targa Resources Partners LP Amendment to Outstanding Performance Units (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP's Current Report on Form 8-K/A filed July 24, 2013 (File No. 001-33303)).
10.28+	Targa Resources Partners LP Performance Unit Grant Agreement under the Targa Resources Corp. Long-Tern Incentive Plan (incorporated by reference to Exhibit 10.4 to Targa Resources Partners LP's Current Report on Form 8-K/A filed July 24, 2013 (File No. 001-33303)).
10.29+	Targa Resources Executive Officer Change in Control Severance Program (incorporated by reference to Exhibit 10.3 to Targa Resources Corp.'s Current Report on Form 8-K filed January 19, 2012 (File No. 001-34991)).

10.30+	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 Corp.'s Current Report on Form 8-K filed December 8, 2015 (File No. 001-34991)).
10.31	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)).
10.32	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)).
10.33	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)).

Number	Description
10.34	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)).
10.35	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 10.2 to Targa Resources

	Corp.'s Quarterly Report on Form 10-Q filed November 3, 2017 (File No. 001-34991)).
10.36*	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).
10.37*	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).
10.38	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)).
10.39	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)).
10.40	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)).
10.41	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 10.3 to Targa Resources Corp.'s Quarterly Report on Form 10-Q filed November 3, 2017 (File No. 001-34991)).
10.42*	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.
10.43*	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
10.44	Indenture dated as of October 28, 2014 among the Issuers, the Guarantors and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP's Current Report on Form 8-K filed October 29, 2014 (File No. 001-33303)).
10.45	Registration Rights Agreement dated as of October 28, 2014 by and among the Issuers, the Guarantors and

	Merrill Lynch, Pierce, Fenner & Smith Incorporated, RBS Securities Inc., Wells Fargo Securities, LLC, Goldman, Sachs & Co. and UBS Securities 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 October 29, 2014 (File No. 001-33303)).
10.46	Supplemental Indenture dated March 10, 2017 to Indenture dated October 28, 2014, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.5 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed May 4, 2017 (File No. 001-33303)).

Number	Description
10.47	Supplemental Indenture dated June 16, 2017 to Indenture dated October 28, 2014, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 10.4 to Targa Resources Corp.'s Quarterly Report on Form 10-Q filed November 3, 2017 (File No. 001-34991)).
10.48*	Supplemental Indenture dated December 18, 2017 to Indenture dated October 28, 2014, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association.

10.49*	Supplemental Indenture dated January 9, 2018 to Indenture dated October 28, 2014, among the Guaranteeing Subsidiary, Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association.
10.50	Indenture, dated as of September 14, 2015, among Targa Resources Partners LP, Targa Resources Finance Partners 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)).
10.51	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)).
10.52	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)).
10.53	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 10.6 to Targa Resources Corp.'s Quarterly Report on Form 10-Q filed November 3, 2017 (File No. 001-34991)).

10.54* 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.

10.55* 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.
10.56	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 10.1 to Targa Resources Corp.'s Current Report on Form 8-K filed October 12, 2016 (File No. 001-34991)).
10.57	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 10.2 to Targa Resources Corp.'s Current Report on Form 8-K filed October 12, 2016 (File No. 001-34991)).
10.58	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 10.3 to Targa Resources Corp.'s Current Report on Form 8-K filed October 12, 2016 (File No. 001-34991)).

Number	Description
10.59	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)).
10.60	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 10.7 to Targa Resources Corp.'s Quarterly Report on Form 10-Q filed November 3, 2017 (File No. 001-34991)).
10.61*	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.
10.62*	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
10.63	Purchase Agreement dated as of October 10,

	2017 among the Issuers, the Guarantors and Citigroup Global Markets Inc., 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 October 12, 2017).
10.64	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).
10.65	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).
10.66*	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.
10.67*	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.
10.68	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)).

10.69 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)).
10.70	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)).
10.71	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)).

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Number	Description
10.72	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)).
10.73	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)).
10.74	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)).
10.75	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)).
10.76+	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)).
10.76+	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)).
10.78+	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)).
10.79+	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)).

10.80+ 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)).

10.81+ 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 Corp.'s Current Report on Form 8-K filed November 16, 2015 (File No. 001-34991)).

10.82+ 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 Corp.'s Current Report on Form 8-K filed November 16, 2015 (File No. 001-34991)).

10.83+ Indemnification Agreement by and

	between Targa Resources Corp. and Dan C. Middlebrooks, dated November 12, 2015 (incorporated by reference to Exhibit 10.3 to Targa Resources Corp.'s Current Report on Form 8-K filed November 16, 2015 (File No. 001-34991)).
10.84+	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 Corp.'s Current Report on Form 8-K filed November 16, 2015 (File No. 001-34991)).
10.85+	Indemnification Agreement by and between Targa Resources Corp. and Robert B. Evans, dated March 1, 2016 (incorporated by reference to Exhibit 10.1 to Targa Resources Corp.'s Current Report on Form 8-K filed March 7, 2016 (File No. 001-34991)).
10.86+	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)).

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Number	Description
10.87	Amended and Restated Registration Rights Agreement dated as of October 31, 2005 (incorporated by reference to Exhibit 10.1 to Targa Resources Corp.'s Registration Statement on Form S-1/A filed November 12, 2010 (File No. 333-169277)).
10.88	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)).
10.89	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)).
10.90	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)).
10.91	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)).
10.92	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)).
10.93	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)).

10.94	Series A Preferred Stock Purchase Agreement, dated February 18, 2016, by and among Targa Resources Corp. and Stonepeak Target Holdings LP (incorporated by reference to Exhibit 10.7 to Targa Resources Corp.'s Quarterly Report on Form 10-Q filed May 10, 2016 (File No. 001-34991)).
10.95	Amendment No. 1 to the Series A Preferred Stock Purchase Agreement dated February 18, 2016, dated March 3, 2016, by and among Targa Resources Corp. and Stonepeak Target Holdings LP (incorporated by reference to Exhibit 10.9 to Targa Resources Corp.'s Quarterly Report on Form 10-Q filed May 10, 2016 (File No. 001-34991)).
10.96	Amendment No. 2 to the Series A Preferred Stock Purchase Agreement dated February 18, 2016, dated March 15, 2016, by and

	among Targa Resources Corp. and Stonepeak Target Holdings LP (incorporated by reference to Exhibit 10.10 to Targa Resources Corp.'s Quarterly Report on Form 10-Q filed May 10, 2016 (File No. 001-34991)).
10.97	Series A Preferred Stock Purchase Agreement, dated March 11, 2016, by and among Targa Resources Corp. and the purchasers party thereto (incorporated by reference to Exhibit 10.11 to Targa Resources Corp.'s Quarterly Report on Form 10-Q filed May 10, 2016 (File No. 001-34991)).
10.98	Amendment No. 1 to the Series A Preferred Stock Purchase Agreement dated March 11, 2016, dated March 15, 2016, by and among Targa Resources Corp. and Stonepeak Target Upper Holdings LLC (incorporated by reference to Exhibit 10.8 to Targa Resources Corp.'s Quarterly

	Report on Form 10-Q filed May 10, 2016 (File No. 001-34991)).
21.1*	List of Subsidiaries of Targa Resources Corp.

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Number	Description
23.1*	Consent of Independent Registered Public Accounting Firm.
31.1*	Certification of the Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.
31.2*	Certification of the Chief Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.
32.1**	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document

101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document

*Filed herewith
**Furnished herewith
***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 Corp. (Registrant)
Date: February 16, 2018	By: /s/ Matthew J. Meloy Matthew J. Meloy Executive Vice President and 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 16, 2018.

Signature	Title (Position with Targa Resources Corp.)
/s/ Joe Bob Perkins Joe Bob Perkins	Chief Executive Officer and Director (Principal Executive Officer)
/s/ Matthew J. Meloy Mathew J. Meloy	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ John R. Klein John R. Klein	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/ Michael A. Heim Michael A. Heim	Vice 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

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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, 2017.

The effectiveness of our internal control over financial reporting as of December 31, 2017 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/ Matthew J. Meloy

Matthew J. Meloy

Executive Vice President and Chief Financial Officer

(Principal Financial Officer)

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Targa Resources Corp.

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Targa Resources Corp. and its subsidiaries as of December 31, 2017 and 2016, and the related consolidated statements of operations, of comprehensive income (loss), of changes in owners' equity and Series A Preferred Stock and of cash flows for each of the three years in the period ended December 31, 2017, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2017, 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 Company as of December 31, 2017 and 2016, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2017 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

Basis for Opinions

The Company'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 Company's consolidated financial statements and on the Company'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 Company 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 16, 2018

We have served as the Company's auditor since 2005.

PART I – FINANCIAL INFORMATION

Item 1. Financial Statements.

TARGA RESOURCES CORP.

CONSOLIDATED BALANCE SHEETS

	December 31, 2017	December 31, 2016
	(In millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 137.2	$ 73.5
Trade receivables, net of allowances of $0.1 and $0.9 million at December 31, 2017 and December 31, 2016	827.6	674.6
Inventories	204.5	137.7
Assets from risk management activities	37.9	16.8
Income tax receivable	—	67.8
Other current assets	62.7	36.4
Total current assets	1,269.9	1,006.8
Property, plant and equipment	14,205.4	12,518.7
Accumulated depreciation	(3,775.4)	(2,827.7)
Property, plant and equipment, net	10,430.0	9,691.0
Intangible assets, net	2,165.8	1,654.0
Goodwill, net	256.6	210.0
Long-term assets from risk management activities	23.2	5.1
Investments in unconsolidated affiliates	221.6	240.8
Other long-term assets	21.5	63.5
Total assets	$ 14,388.6	$ 12,871.2
LIABILITIES, SERIES A PREFERRED STOCK AND OWNERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 1,186.9	$ 843.5
Liabilities from risk management activities	79.7	49.1
Current debt obligations	350.0	275.0
Total current liabilities	1,616.6	1,167.6
Long-term debt	4,703.0	4,606.0
Long-term liabilities from risk management activities	19.6	26.1
Deferred income taxes, net	479.0	941.2
Other long-term liabilities	597.9	215.1
Contingencies (see Note 20)		
Series A Preferred 9.5% Stock, $1,000 per share liquidation preference, (1,200,000 shares authorized, issued and outstanding 965,100 shares), net of discount (see Note 12)	216.5	190.8
Owners' equity:		

Targa Resources Corp. stockholders' equity:				
Common stock ($0.001 par value, 300,000,000 shares authorized)			0.2	0.2
	Issued	Outstanding		
December 31, 2017	218,152,620	217,566,980		
December 31, 2016	185,234,405	184,720,525		
Preferred stock ($0.001 par value, after designation of Series A Preferred Stock: 98,800,000 shares authorized, no shares issued and outstanding)			—	—
Additional paid-in capital			6,302.8	5,506.2
Retained earnings (deficit)			(77.2)	(187.3)
Accumulated other comprehensive income (loss)			(29.9)	(38.3)
Treasury stock, at cost (585,640 shares as of December 31, 2017 and 513,880 as of December 31, 2016)			(35.6)	(32.2)
Total Targa Resources Corp. stockholders' equity			6,160.3	5,248.6
Noncontrolling interests in subsidiaries			595.7	475.8
Total owners' equity			6,756.0	5,724.4
Total liabilities, Series A Preferred Stock and owners' equity			$14,388.6	$ 12,871.2

See notes to consolidated financial statements.

TARGA RESOURCES CORP.

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31, 2017	2016	2015
	(In millions, except per share amounts)		
Revenues:			
Sales of commodities	$7,751.1	$5,626.8	$5,465.4
Fees from midstream services	1,063.8	1,064.1	1,193.2
Total revenues	8,814.9	6,690.9	6,658.6
Costs and expenses:			
Product purchases	6,906.1	4,922.9	4,837.6
Operating expenses	622.9	553.7	540.0
Depreciation and amortization expense	809.5	757.7	644.5
General and administrative expense	203.4	187.2	161.7
Impairment of property, plant and equipment	378.0	—	32.6
Impairment of goodwill	—	207.0	290.0
Other operating (income) expense	17.4	6.6	(7.1)
Income (loss) from operations	(122.4)	55.8	159.3
Other income (expense):			
Interest expense, net	(233.7)	(254.2)	(231.9)
Equity earnings (loss)	(17.0)	(14.3)	(2.5)
Gain (loss) from financing activities	(16.8)	(48.2)	(10.1)
Change in contingent considerations	99.6	0.4	1.2
Other, net	(2.6)	0.8	(27.8)
Income (loss) before income taxes	(292.9)	(259.7)	(111.8)
Income tax (expense) benefit	397.1	100.6	(39.6)
Net income (loss)	104.2	(159.1)	(151.4)
Less: Net income (loss) attributable to noncontrolling interests	50.2	28.2	(209.7)
Net income (loss) attributable to Targa Resources Corp.	54.0	(187.3)	58.3
Dividends on Series A Preferred Stock	91.7	72.6	—
Deemed dividends on Series A Preferred Stock	25.7	18.2	—
Net income (loss) attributable to common shareholders	$(63.4)	$(278.1)	$58.3
Net income (loss) per common share - basic	$(0.31)	$(1.80)	$1.09
Net income (loss) per common share - diluted	$(0.31)	$(1.80)	$1.09
Weighted average shares outstanding - basic	206.9	154.4	53.5
Weighted average shares outstanding - diluted	206.9	154.4	53.6
Dividends per common share declared for the period	$3.64	$3.64	$3.39

See notes to consolidated financial statements.

TARGA RESOURCES CORP.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Year Ended December 31, 2017			2016			2015		
	Pre-Tax	Related Income Tax	After Tax	Pre-Tax	Related Income Tax	After Tax	Pre-Tax	Related Income Tax	After Tax
	(In millions)								
Net income (loss) attributable to Targa Resources Corp.			$ 54.0			$ (187.3)			$ 58.3
Other comprehensive income (loss) attributable to Targa Resources Corp.									
Commodity hedging contracts:									
Change in fair value	$ (28.8)	$ 13.5	(15.3)	$ (127.3)	$ 48.5	(78.8)	$ 11.0	$ (4.2)	6.8
Settlements reclassified to revenues	44.6	(20.9)	23.7	(33.8)	12.8	(21.0)	(9.5)	3.6	(5.9)
Other comprehensive income (loss) attributable to Targa Resources Corp.	15.8	(7.4)	8.4	(161.1)	61.3	(99.8)	1.5	(0.6)	0.9
Comprehensive income (loss) attributable to Targa Resources Corp.			$ 62.4			$ (287.1)			$ 59.2
Net income (loss) attributable to noncontrolling interests			$ 50.2			$ 28.2			$ (209.7)
Other comprehensive income (loss) attributable to noncontrolling interests									
Commodity hedging contracts:									
Change in fair value	—	—	—	23.7	—	23.7	101.7	—	101.7
Settlements reclassified to revenues	—	—	—	(11.2)	—	(11.2)	(76.8)	—	(76.8)
Other comprehensive income (loss) attributable to noncontrolling interests	—	—	—	12.5	—	12.5	24.9	—	24.9
Comprehensive income (loss) attributable to noncontrolling interests			$ 50.2			$ 40.7			$ (184.8)
Total									
Net income (loss)			$ 104.2			$ (159.1)			$ (151.4)
Other comprehensive income (loss)									
Commodity hedging contracts:									

Change in fair value	(28.8)	13.5	(15.3)	(103.6)	48.5	(55.1)	112.7	(4.2)	108.5
Settlements reclassified to revenues	44.6	(20.9)	23.7	(45.0)	12.8	(32.2)	(86.3)	3.6	(82.7)
Other comprehensive income (loss)	$ 15.8	$ (7.4)	8.4	$ (148.6)	$ 61.3	(87.3)	$ 26.4	$ (0.6)	25.8
Total comprehensive income (loss)			$ 112.6			$ (246.4)			$ (125.6)

See notes to consolidated financial statements.

TARGA RESOURCES CORP.

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

	Common Stock		Additional Paid in	Retained Earnings (Accumulated	Accumulated Other Comprehensive Income	Treasury Shares		Noncontrolling	Total Owner's	Series A Preferred
	Shares	Amount	Capital	Deficit)	(Loss)	Shares	Amount	Interests	Equity	Stock
	(In millions, except shares in thousands)									
Balance, December 31, 2014	42,143	$—	$164.9	$25.5	$4.8	389	$(25.4)	$2,369.7	$2,539.5	$—
Compensation on equity grants, net of excess tax benefits	—	—	9.5	—	—	—	—	16.6	26.1	—
Distribution equivalent rights	—	—	(0.8)	—	—	—	—	(1.6)	(2.4)	—
Shares issued under compensation program	50	—	—	—	—	—	—	—	—	—
Shares and units tendered for tax withholding obligations	(37)	—	—	—	—	37	(3.3)	(5.5)	(8.8)	—
Sale of Partnership limited partner interests	—	—	—	—	—	—	—	436.0	436.0	—
Issuance of common stock	3,738	—	335.5	—	—	—	—	—	335.5	—
Impact of subsidiary equity transactions	—	—	56.8	—	—	—	—	(56.8)	—	—
Dividends	—	—	—	(179.0)	—	—	—	—	(179.0)	—
Dividends in excess of retained earnings	—	—	(122.1)	122.1	—	—	—	—	—	—
	—	—	—	—	—	—	—	(514.8)	(514.8)	—

Distributions to noncontrolling interests										
Distributions payable to preferred unitholders	—	—	—	—	—	—	—	(0.9)	(0.9)	—
Contributions from noncontrolling interests	—	—	—	—	—	—	—	78.4	78.4	—
Noncontrolling interests in acquired subsidiaries	—	—	—	—	—	—	—	216.8	216.8	—
Common stock issued in ATLS merger	10,126	0.1	1,013.6	—	—	—	—	—	1,013.7	—
Partnership units issued in APL merger	—	—	—	—	—	—	—	2,435.7	2,435.7	—
Other comprehensive income (loss)	—	—	—	—	0.9	—	—	24.9	25.8	—
Net income	—	—	—	58.3	—	—	—	(209.7)	(151.4)	—
Balance, December 31, 2015	56,020	$ 0.1	$ 1,457.4	$ 26.9	$ 5.7	426	$ (28.7)	$ 4,788.8	$ 6,250.2	$ —
Compensation on equity grants	—	—	27.5	—	—	—	—	2.2	29.7	—
Distribution equivalent rights	—	—	(8.7)	—	—	—	—	(0.2)	(8.9)	—
Shares issued under compensation program	364	—	—	—	—	—	—	—	—	—
Shares and units tendered for tax withholding obligations	(88)	—	—	—	—	88	(3.5)	(0.1)	(3.6)	—
Issuance of common stock	12,562	—	572.7	—	—	—	—	—	572.7	—
Issuance of Series A preferred and detachable warrants	—	—	796.6	—	—	—	—	—	796.6	172.6
Exercise of warrants -	11,337	—	—	—	—	—	—	—	—	—

shares settled										
Series A Preferred Stock dividends										
Dividends	—	—	—	(72.6)	—	—	—	—	(72.6)	—
Dividends in excess of retained earnings	—	—	(68.8)	68.8	—	—	—	—	—	—
Deemed dividends - accretion of beneficial conversion feature	—	—	(18.2)	—	—	—	—	—	(18.2)	18.2
Common stock dividends										
Dividends	—	—	—	(513.7)	—	—	—	—	(513.7)	—
Dividends in excess of retained earnings	—	—	(490.6)	490.6	—	—	—	—	—	—
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(177.0)	(177.0)	—
Contributions from noncontrolling interests	—	—	—	—	—	—	—	43.3	43.3	—
Acquisition of TRP noncontrolling common interests, net of acquisition costs and deferred income taxes	104,526	0.1	3,183.7	—	55.8	—	—	(4,119.7)	(880.1)	—
Purchase of noncontrolling interests in subsidiary, net of tax impact	—	—	54.6	—	—	—	—	(102.2)	(47.6)	—
Other comprehensive income (loss)	—	—	—	—	(99.8)	—	—	12.5	(87.3)	—
Net income (loss)	—	—	—	(187.3)	—	—	—	28.2	(159.1)	—
Balance, December 31, 2016	184,721	$ 0.2	$ 5,506.2	$ (187.3)	$ (38.3)	514	$ (32.2)	$ 475.8	$ 5,724.4	$ 190.8

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TARGA RESOURCES CORP.

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

	Common Stock		Additional Paid in	Retained Earnings (Accumulated	Accumulated Other Comprehensive Income	Treasury Shares		Noncontrolling	Total Owner's	Series A Preferred
	Shares	Amount	Capital	Deficit)	(Loss)	Shares	Amount	Interests	Equity	Stock
	(In millions, except shares in thousands)									
Balance, December 31, 2016	184,721	$0.2	$5,506.2	$(187.3)	$(38.3)	514	$(32.2)	$475.8	$5,724.4	$190.8
Impact of accounting standard adoption (see Note 3)	—	—	—	56.1	—	—	—	—	56.1	—
Compensation on equity grants	—	—	42.3	—	—	—	—	—	42.3	—
Distribution equivalent rights	—	—	(9.7)	—	—	—	—	—	(9.7)	—
Shares issued under compensation program	285	—	—	—	—	—	—	—	—	—
Shares and units tendered for tax withholding obligations	(72)	—	—	—	—	72	(3.4)	—	(3.4)	—
Issuance of common stock	32,633	—	1,644.4	—	—	—	—	—	1,644.4	—
Series A Preferred Stock dividends										
Dividends	—	—	—	(91.7)	—	—	—	—	(91.7)	—
Dividends in excess of retained earnings	—	—	(91.7)	91.7	—	—	—	—	—	—
Deemed dividends - accretion of beneficial conversion feature	—	—	(25.7)	—	—	—	—	—	(25.7)	25.7
Common stock dividends										
Dividends	—	—	—	(749.4)	—	—	—	—	(749.4)	—
Dividends in excess of retained earnings	—	—	(749.4)	749.4	—	—	—	—	—	—
Distributions to noncontrolling interests	—	—	—	—	—	—	—	(59.4)	(59.4)	—
Contributions from noncontrolling interests	—	—	—	—	—	—	—	141.6	141.6	—
Purchase of noncontrolling interests	—	—	(13.6)	—	—	—	—	(12.5)	(26.1)	—

in subsidiaries, net of tax impact										
Other comprehensive income (loss)	—	—	—	—	8.4	—	—	—	8.4	—
Net income (loss)	—	—	—	54.0	—	—	—	50.2	104.2	—
Balance, December 31, 2017	217,567	$0.2	$6,302.8	$(77.2)	$(29.9)	586	$(35.6)	$595.7	$6,756.0	$216.5

See notes to consolidated financial statements.

TARGA RESOURCES CORP.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2017	2016	2015
	(In millions)		
Cash flows from operating activities			
Net income (loss)	$104.2	$(159.1)	$(151.4)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Amortization in interest expense	11.5	14.9	15.3
Compensation on equity grants	42.3	29.7	25.0
Depreciation and amortization expense	809.5	757.7	644.5
Impairment of property, plant and equipment	378.0	—	32.6
Impairment of goodwill	—	207.0	290.0
Accretion of asset retirement obligations	3.9	4.6	5.3
Increase (decrease) in redemption value of mandatorily redeemable preferred interests	3.3	(15.2)	(30.6)
Deferred income tax expense (benefit)	(392.7)	(37.8)	24.6
Equity (earnings) loss of unconsolidated affiliates	17.0	14.3	2.5
Distributions of earnings received from unconsolidated affiliates	12.5	4.1	13.8
Risk management activities	47.0	38.8	71.1
(Gain) loss on sale or disposition of assets	15.9	6.1	(8.0)
(Gain) loss from financing activities	16.8	48.2	10.1
Change in contingent considerations included in Other expense (income)	(99.6)	(0.4)	(1.2)
Changes in operating assets and liabilities, net of business acquisitions:			
Receivables and other assets	(57.1)	(235.7)	235.9
Inventories	(73.2)	(15.9)	41.4
Accounts payable and other liabilities	100.2	176.1	(186.2)
Net cash provided by operating activities	939.5	837.4	1,034.7
Cash flows from investing activities			
Outlays for property, plant and equipment	(1,297.5)	(562.1)	(817.2)
Outlays for business acquisition, net of cash acquired	(570.8)	-	(1,574.4)
Investments in unconsolidated affiliates	(9.5)	(4.4)	(11.7)
Return of capital from unconsolidated affiliates	0.2	4.1	1.2
Other, net	(15.1)	3.8	2.5
Net cash used in investing activities	(1,892.7)	(558.6)	(2,399.6)
Cash flows from financing activities			
Debt obligations:			
Proceeds from borrowings under credit facilities	2,701.0	2,322.0	2,488.0
Repayments of credit facilities	(2,671.0)	(2,617.0)	(1,870.0)
Proceeds from borrowings under accounts receivable securitization facility	666.6	171.4	391.6
Repayments of accounts receivable securitization facility	(591.6)	(115.7)	(355.1)
Proceeds from issuance of senior notes and term loan	750.0	1,000.0	2,122.5
Redemption of senior notes and term loan	(698.1)	(1,852.2)	(284.3)
Redemption of TPL senior notes	—	(13.3)	(1,168.8)

Proceeds from issuance of common stock	1,660.4	577.3	336.8
Proceeds from issuance of preferred stock and warrants	—	994.1	—
Proceeds from sale of Partnership common and preferred units	—	—	443.6
Costs incurred in connection with financing arrangements	(23.5)	(71.4)	(54.3)
Repurchase of shares and units under compensation plans	(3.4)	(3.6)	(8.8)
Purchase of noncontrolling interests in subsidiary	(12.5)	(37.2)	—
Contributions from noncontrolling interests	141.6	43.3	78.4
Distributions to noncontrolling interests	(48.1)	(26.7)	(14.4)
Distributions to Partnership unitholders	(11.3)	(150.3)	(500.4)
Dividends paid to common and Series A preferred shareholders	(843.2)	(565.9)	(179.0)
Other, net	—	(0.3)	(1.7)
Net cash provided by (used in) financing activities	1,016.9	(345.5)	1,424.1
Net change in cash and cash equivalents	63.7	(66.7)	59.2
Cash and cash equivalents, beginning of period	73.5	140.2	81.0
Cash and cash equivalents, end of period	$137.2	$73.5	$140.2

See notes to consolidated financial statements.

TARGA RESOURCES CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

Note 1 — Organization and Operations

Our Organization

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

Our Operations

The Company is engaged in the business of:

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

See Note 26 – Segment Information for certain financial information regarding our business segments.

Note 2 — Basis of Presentation

These accompanying financial statements and related notes present our consolidated financial position as of December 31, 2017 and 2016, and the results of operations, comprehensive income, cash flows, and changes in owners' equity for the years ended December 31, 2017, 2016 and 2015.

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.

One of our indirect subsidiaries is the sole general partner of Targa Resources Partners LP ("the Partnership" or "TRP"). As of February 16, 2016, our interests in the Partnership consisted of the following:

- a 2% general partner interest, which we hold through our 100% ownership interest in the general partner of the Partnership;
- all Incentive Distribution Rights ("IDRs");
- 16,309,594 common units representing limited partner interests in the Partnership ("common units"), representing an 8.8% limited partnership interest; and

- a Special GP Interest representing retained tax benefits related to the contribution to the Partnership from us of the APL general partner interest acquired in the ATLS merger (as defined in Note 4 – Business Acquisitions).

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

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

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

As we continued to control the Partnership after the TRC/TRP Merger, the resulting change in our ownership interest was accounted for as an equity transaction, which is reflected in our Consolidated Balance Sheets as a reduction of noncontrolling interests and a corresponding increase in common stock and additional paid in capital. The TRC/TRP Merger was a taxable exchange that resulted in a book/tax difference in the basis of the underlying assets acquired (our investment in TRP). The tax impact is presented as a reduction of additional paid-in capital consistent with the accounting for tax effects of transactions with noncontrolling interests. See Note 23 – Income Taxes. The following table summarizes the financial effects of the TRC/TRP Merger:

	Common shares	Additional paid-in capital	Retained earnings	Accumulated other comprehensive income (loss)	TRC's stockholders' equity	Noncontrolling interests (1)	Total owners' equity
Shares issued for the Merger	$ 0.1	$ 1,803.0	$ —	$ —	$ 1,803.1	$ (4,119.7)	$ (2,316.6)
Impact of NCI acquisition on TRC owners' equity	—	2,226.7	—	89.9	2,316.6	—	2,316.6
Deferred tax adjustments	—	(831.0)	—	(34.1)	(865.1)	—	(865.1)
Transaction costs, net of tax	—	(15.0)	—	—	(15.0)	—	(15.0)
Acquisition of TRP noncontrolling common interests	$ 0.1	$ 3,183.7	$ —	$ 55.8	$ 3,239.6	$ (4,119.7)	$ (880.1)

(1) Reflects the February 17, 2016 book value of the publicly held interests in TRP.

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

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

Subsequent Event

On February 6, 2018, we announced the formation of three development joint ventures (the “DevCo JVs”) with investment vehicles affiliated with Stonepeak Infrastructure Partners (“Stonepeak”). Stonepeak will own an 80% interest in both the GCX DevCo JV, which will own our 25% interest in the Gulf Coast Express Pipeline (“GCX”), and the Fractionation DevCo JV, which will own a 100% interest in some of the assets associated with a newly announced 100 MBbl/d fractionation train in Mont Belvieu, Texas, expected to begin operations in the first quarter of 2019. Stonepeak will own a 95% interest in the Grand Prix DevCo JV, which will own a 20% interest in the Grand Prix pipeline (“Grand Prix”). We will hold the remaining interest of the DevCo JVs as well as control the management, construction and operation of Grand Prix and fractionation train.

For a four-year period beginning on the earlier of the date that all three projects have commenced commercial operations or January 1, 2020, Targa has the option to acquire all or part of Stonepeak’s interests in the DevCo JVs. Targa may acquire up to 50% of Stonepeak’s invested capital in multiple increments with a minimum of $100 million, and would be required to buy Stonepeak’s remaining 50% interest in a single final purchase.

Note 3 — Significant Accounting Policies

Consolidation Policy

Our consolidated financial statements include our accounts and those of our subsidiaries in which we have a controlling interest. We hold varying undivided interests in various gas gathering and processing facilities in which we are responsible for our proportionate share of the costs and expenses of the facilities. Our consolidated financial statements reflect our proportionate share of the revenues, expenses, assets and liabilities of these undivided interests.

We follow the equity method of accounting when we do not exercise control over the investee, but we can exercise significant influence over the operating and financial policies of the investee. Under this method, our equity investments are carried originally at our acquisition cost, increased by our proportionate share of the investee's net income and by contributions made, and decreased by our proportionate share of the investee's net losses and by distributions received. 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. Adjustments made with respect to the use of these estimates and judgments often relate to information not previously available. Uncertainties with respect to such estimates and judgments are inherent in the preparation of financial statements. Estimates and judgments are used in, among other things, (1) estimating unbilled revenues, product purchases and operating and general and administrative costs, (2) developing fair value assumptions, including estimates of future cash flows and discount rates, (3) analyzing goodwill and long-lived assets for possible impairment, (4) estimating the useful lives of assets, (5) determining amounts to accrue for contingencies, guarantees and indemnifications and (6) estimating redemption value of mandatorily redeemable preferred interests. Actual results, therefore, could differ materially from estimated amounts.

Cash and Cash Equivalents

Cash and cash equivalents include all cash on hand, demand deposits, and investments with original maturities of three months or less. We consider cash equivalents to include short-term, highly liquid investments that are readily convertible to known amounts of cash and which are subject to an insignificant risk of changes in value. Checks outstanding at the end of a period are reclassified to accounts payable, as we extinguish liabilities when the creditor receives our payment and we are relieved of our obligation (which generally occurs when our bank honors that check).

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.

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 to make required payments, economic events and other factors. As the financial condition of any party changes, circumstances develop or additional information becomes available, adjustments to an allowance for doubtful accounts may be required.

Inventories

Our inventories consist primarily of NGL product inventories. 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. NGL product inventories are valued at the lower of cost or net realizable value using the average cost method. Commodity inventories that are not physically or contractually available for sale under normal operations ("deadstock") are classified as Property, Plant and Equipment. Inventories also include materials and supplies required for our Badlands expansion activities in North Dakota, which are valued at cost using the specific identification method.

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 cash flows due to fluctuating energy prices. All derivative instruments not qualifying for the normal purchase and normal sale exception are recorded on the balance sheets at fair value. The treatment of the periodic changes in fair value will depend on whether the derivative is designated and effective as a hedge for accounting purposes. We have designated certain liquids marketing contracts that meet the definition of a derivative as normal purchases and normal sales, which under GAAP, are not accounted for as derivatives. As a result, the revenues and expenses associated with such contracts are recognized during the period when volumes are physically delivered or received.

If a derivative qualifies for hedge accounting and is designated as a cash flow hedge, the effective portion of the change in fair value of the derivative is deferred in Accumulated Other Comprehensive Income (“AOCI”), a component of owners’ equity, and reclassified to earnings when the forecasted transaction occurs. 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. As such, we include the cash flows from commodity derivative instruments in revenues.

If a derivative does not qualify as a hedge or is not designated as a hedge, the gain or loss resulting from the change in fair value on the derivative is recognized currently in earnings as a component of revenues.

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 offsetting changes in cash flows of hedged items.

The relationship between the hedging instrument and the hedged item must be highly effective in achieving the offset of changes in cash flows attributable to the hedged risk both at the inception of the contract and on an ongoing basis. We measure hedge ineffectiveness on a quarterly basis and reclassify any ineffective portion of the gain or loss related to the change in fair value to earnings in the current period.

We will discontinue hedge accounting on a prospective basis when a hedge instrument is terminated or ceases to be highly effective. 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 no longer probable that a hedged forecasted transaction will occur, deferred gains or losses on the hedging instrument are reclassified to earnings immediately.

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.

Property, Plant and Equipment

Property, plant and equipment are stated at acquisition value less accumulated depreciation. Depreciation is computed using the straight-line method over the estimated useful lives of the assets.

Expenditures for maintenance and repairs are expensed as incurred. Expenditures to refurbish assets that extend the useful lives or prevent environmental contamination are capitalized and depreciated over the remaining useful life of the asset or major asset component. We also capitalize certain costs directly related to the construction of assets, including internal labor costs, interest and engineering costs.

The determination of the useful lives of property, plant and equipment requires us to make various assumptions, including the supply of and demand for hydrocarbons in the markets served by our assets, normal wear and tear of the facilities, and the extent and frequency of maintenance programs.

We evaluate the recoverability of our property, plant and equipment when events or circumstances such as economic obsolescence, the business climate, legal and other factors indicate we may not recover the carrying amount of the assets. 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. 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. Upon disposition or retirement of property, plant and equipment, any gain or loss is recorded to operations.

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 amortized, but is assessed annually to determine whether its carrying value has been impaired. Goodwill must be attributed to reporting units for the purpose of impairment testing. A reporting unit is an operating segment or one level below an operating segment (also known as a component).

Our annual goodwill impairment test is performed as of November 30, as well as whenever events or changes in circumstances indicate it is more likely than not that the fair value of the reporting unit is less than the carrying amount. 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, to the extent triggering events exist, and 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.

We are permitted to first assess qualitative factors for a reporting unit to determine if the quantitative goodwill impairment test is necessary. If we choose to bypass this qualitative assessment or otherwise 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). Prior to our adoption of ASU 2017-04 (see "Recent Accounting Pronouncements"), if a reporting unit's carrying amount exceeded the reporting unit's fair value, we then compared the implied fair value of goodwill to its carrying value. 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, or prior to our adoption of ASU 2017-04, the amount by which the carrying amount exceeded the reporting unit's implied fair value. The goodwill impairment loss will not exceed the total amount of goodwill allocated to that reporting unit. Additionally, we consider income tax effects from any tax deductible goodwill on the carrying amount of the reporting unit when measuring the goodwill impairment loss, if applicable.

Intangible Assets

Intangible assets arose from 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. Amortization expense attributable to these assets is recorded in a manner that closely resembles the expected benefit pattern of the intangible assets, or where such pattern is not readily determinable, on a straight-line basis, over the periods in which we benefit from services provided to customers.

Asset Retirement Obligations

We record the fair value of estimated asset retirement obligations (“ARO”) associated with tangible long-lived assets. Retirement obligations associated with long-lived assets are only recognized for those for which there is a legal obligation to settle under existing or enacted law, statute, written or oral contract or by legal construction. These obligations, which are estimated based on discounted cash flow estimates, are accreted to full value over time as a period cost. In addition, asset retirement costs are capitalized as part of the related asset’s carrying value and are depreciated over the asset’s respective useful life.

At least annually, we review the projected timing and amount of asset retirement obligations. Changes resulting from revisions to the timing or the amount of the undiscounted cash flows are recognized as an increase or decrease in the carrying amount of the retirement obligation and the related asset retirement cost capitalized as part of the carrying amount of the related long-lived asset. Upon settlement, any difference between the recorded amount and the actual settlement cost will be recognized at a gain or loss.

Debt Issuance Costs

Costs incurred in connection with the issuance of long-term debt are deferred and charged to interest expense over the term of the related debt, as are any original issue discount or premium. 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 from 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 Partnership’s 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

Liabilities for loss contingencies, including environmental remediation costs arising from claims, assessments, litigation, fines, penalties and other sources are charged to operating expense when it is probable that a liability has been incurred and the amount of the loss can be reasonably estimated.

Income Taxes

We account for income taxes using the asset and liability method of accounting for deferred income taxes and provide deferred income taxes for all significant temporary differences based on legislated tax rates during the periods that the timing differences are scheduled to reverse.

As part of the process of preparing our consolidated financial statements, we are required to estimate our income taxes in each of the jurisdictions in which we operate. 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 reported on a net basis 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.

Noncontrolling Interests

Third-party ownership (other than mandatorily redeemable interests) in the net assets of our consolidated subsidiaries is shown 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.

Mandatorily Redeemable Preferred Interests

Mandatorily redeemable preferred interests are included in other long term liabilities (or assets) 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 become payable (or receivable) in the future when the interests are redeemed. Changes in the redemption value are recorded in interest expense, net in our Consolidated Statements of Operations.

Revenue Recognition

Our operating revenues are primarily derived from the following activities:

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

We recognize revenues when all of the following criteria are met: (1) persuasive evidence of an exchange arrangement exists, if applicable, (2) delivery has occurred or services have been rendered, (3) the price is fixed or determinable and (4) collectability is reasonably assured.

For natural gas processing activities, we receive either fees and/or a percentage of proceeds from commodity sales as payment for these services, depending on the type of contract. Under fee-based contracts, we receive a fee based on throughput volumes. Under percent-of-proceeds contracts, we receive either an agreed upon percentage of the actual proceeds we receive from our sales of the residue natural gas and NGLs or an agreed upon percentage based on index related prices for the natural gas and NGLs. Typically, our percent-of-proceeds contracts also include a fee-based component. Percent-of-value and percent-of-liquids contracts are variations on this arrangement. Under keep-whole contracts, we retain the NGLs extracted and return the processed natural gas or value of the natural gas to the producer. A significant portion of our Straddle plant processing contracts are hybrid contracts under which settlements are made on a percent-of-liquids basis or a fee basis, depending on market conditions. Natural gas or NGLs that we purchase are in turn sold and recognized in accordance with the criteria outlined above.

We generally report sales revenues gross in our Consolidated Statements of Operations, as we typically act as the principal in the transactions where we receive commodities, take title to the natural gas and NGLs, and incur the risks and rewards of ownership. However, buy-sell transactions that involve purchases and sales of inventory with the same counterparty that are legally contingent or in contemplation of one another are reported as a single transaction on a combined net basis.

We have certain long-term contractual arrangements under which we have received consideration, but which require future performance by Targa. These arrangements result in deferred revenue, which will be recognized as revenue during the periods that services will be provided. Deferred revenue is included in Other long-term liabilities on our Consolidated Balance Sheets.

Share-Based Compensation

We award share-based compensation to employees, directors and non-management directors in the form of restricted stock, restricted stock units, and performance share units. Compensation expense on restricted stock, restricted stock units, and performance share unit 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 performance share unit 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 recognized in general and administrative expense over the requisite service period of each award. In addition, we account for forfeitures when they occur. We may withhold shares to satisfy employees' tax withholding obligations on vested awards. The withheld shares are recorded by us in treasury stock at cost. Cash paid by us when directly withholding shares for tax-withholding purposes is classified as a financing activity on the statement of cash flows. All excess tax benefits and tax deficiencies related to share-based compensation are recognized as income tax benefit or expense in the income statement with the tax effects of exercised or vested awards treated as discrete items in the reporting period which they occur. Excess tax benefits are classified as an operating activity.

Earnings per Share

We account for earnings per share (“EPS”) in accordance with Accounting Standards Codification (“ASC”) Topic 260 – Earnings per Share. Diluted EPS reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock or resulted in the issuance of common stock so long as it does not have an anti-dilutive effect on EPS. The dilutive effect is determined through the application of the treasury stock method. The assumed proceeds under the treasury stock method exclude windfall tax benefits. Securities that meet the definition of a participating security are required to be considered for inclusion in the computation of basic EPS.

Recent Accounting Pronouncements

Revenue from Contracts with Customers

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standard Update (“ASU”) No. 2014-09, Revenue from Contracts with Customers (Topic 606), which supersedes the revenue recognition requirements in Topic 605, Revenue Recognition, and most industry-specific guidance. The update also creates a new Subtopic 340-40, Other Assets and Deferred Costs – Contracts with Customers, which provides guidance for the incremental costs of obtaining a contract with a customer and those costs incurred in fulfilling a contract with a customer that are not in the scope of another topic. The new revenue standard requires that entities should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entities expect to be entitled in exchange for those goods or services. To achieve that core principle, the standard requires a five step process of (1) identifying the contracts with customers, (2) identifying the performance obligations in the contracts, (3) determining the transaction price, (4) allocating the transaction price to the performance obligations, and (5) recognizing revenue when, or as, the performance obligations are satisfied. The amendment also requires enhanced disclosures regarding the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers.

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

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

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

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

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

We have disaggregated contracts within our two segments and have completed our review of contracts and transaction types with counterparties in order to finalize the new standard's impact on our current revenue recognition and disclosure policies upon adoption. As further discussed below, the new standard will affect the classification between revenue and cost of sales on the income statement as well as the reporting of gross vs. net revenues. We are also anticipating additional disclosures for fixed consideration allocated to performance obligations that are unsatisfied (or partially unsatisfied) as of the end of the current reporting period, separate presentation of revenue from contracts with customers and non-customer revenue (i.e. the effects of derivative activity and lease revenue) as well as unbilled receivables and deferred revenue. The new revenue recognition standard is effective for us on January 1, 2018, and will be adopted using the modified retrospective method. At this time, we do not expect a material cumulative effect adjustment to retained earnings on January 1, 2018. A cross-functional team was established to implement the new standard. Effective January 1, 2018, we have established data requirements, including changes in system mapping and configuration for the prospective reporting under the new standard, and have documented the required process changes, identified key risks and designed mitigating controls.

Gathering and Processing Segment

We have concluded that the contracts within our Gathering and Processing segment where we purchase and obtain control of the entire natural gas stream are contracts with suppliers rather than customers and therefore, not included in the scope of Topic 606. However, these supplier contracts are subject to updated guidance in ASC 705, Cost of Sales and Services, whereby any embedded fees within such contracts, which historically have been reported as "Fees from midstream services," will be reported instead as a reduction of "Product purchases" upon adoption of Topic 606. In addition, we have concluded that in most cases, we are acting as the principal in the sale of commodities to end customers. In instances where we do not control the commodities, we are acting as an agent for the supplier and will recognize revenue for the net amount of consideration we expect to retain in exchange for our service.

In certain contracts, our Gathering and Processing segment purchases and obtains control of only one component of the natural gas stream (i.e. residue gas or NGLs). Such arrangements contain both a supply and a service revenue element and therefore are partially in the scope of Topic 606. That is, the counterparty is a supplier for our cash settled purchase of one component of the natural gas stream and a customer with regards to the service provided to gather, process, and redeliver the other component. Upon adoption, each element will be measured at its standalone selling price. For contracts with a service element, if we obtain noncash consideration in the form of commodities, such consideration will be recognized as revenue from services. This is a change from our historical accounting practice, whereby the revenue related to the commodities retained in kind (i.e. noncash consideration) is only recorded once those commodities are sold to a third party, and is generally classified as "Sales of commodities" revenue without a corresponding cost of sales. We are not anticipating a significant change in the timing of revenue recognition for the contracts within our Gathering and Processing segment with a customer.

Logistics and Marketing Segment

We are not anticipating a significant change in revenue recognition for the contracts within our Logistics and Marketing segment. However, consistent with the discussion above for our Gathering and Processing segment, the embedded fees within our contracts where we purchase and obtain control of the commodities, which historically have been presented as "Fees from midstream services", will be reported as a reduction of "Product purchases" upon adoption of the new standard. In addition, for contracts structured as a purchase where we do not control the commodities (i.e. we are acting as an agent), we will recognize revenue for the net amount of consideration we expect to retain.

Leases

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

In January 2018, the FASB issued ASU 2018-01, Leases (Topic 842): Land Easement Practical Expedient for Transition to Topic 842. The amendments permit an entity to elect an optional transition practical expedient to not apply Topic 842 to land easements that exist or expired before the effective date of Topic 842 and that were not previously assessed under Topic 840. An entity would be required to apply the practical expedient consistently to all of its existing or expired land easements that were not previously assessed under Topic 840.

Measurement of Credit Losses on Financial Instruments

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

Cash Flow Classification

In August 2016, the FASB issued ASU 2016-15, Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments (a consensus of the Emerging Issues Task Force). These amendments clarify how entities should classify certain cash receipts and cash payments in the statement of cash flows related to the following transactions: (1) debt prepayment or extinguishment costs; (2) settlement of zero-coupon debt instruments or other debt instruments with coupon rates that are insignificant in relation to the effective interest rate of the borrowing; (3) contingent consideration payments made after a business combination; (4) proceeds from the settlement of insurance claims; (5) proceeds from the settlement of corporate-owned life insurance; (6) distributions received from equity method investees; and (7) beneficial interests in securitization transactions. Additionally, the update clarifies how the predominance principle should be applied when cash receipts and cash payments have aspects of more than one class of cash flows. These amendments are effective for fiscal years, and interim periods within those years, beginning after December 15, 2017, with early adoption permitted. We plan to adopt the applicable amendments in the first quarter of 2018 and expect a minimal effect on our consolidated financial statements.

Recognition of Intra-Entity Transfers of Assets Other than Inventory

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

We early adopted the applicable amendments in first quarter of 2017 on a modified retrospective basis which resulted in a cumulative effect adjustment on retained earnings as of January 1, 2017 of $56.1 million in order to recognize unamortized tax expense previously deferred of $40.1 million and deferred tax assets previously unrecognized of $96.2 million. We did not have any other intra-entity transfers of assets other than inventory during the year ended December 31, 2017.

Business Combinations

In January 2017, the FASB issued ASU 2017-01, Business Combinations (Topic 805): Clarifying the Definition of a Business. The amendments clarify the definition of a business to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses by providing an initial required screen to determine when an integrated set of assets and activities is not a business. The screen requires that when substantially all of the fair value of the gross assets acquired (or disposed of) is concentrated in a single identifiable asset or a group of similar identifiable assets, the set is not a business. This screen reduces the number of transactions that need to be further evaluated. If the screen is not met, then the amendments (1) require that to be considered a business, a set must include, at a minimum, an input and a substantive process that together significantly contribute to the ability to create output and (2) remove the evaluation of whether a market participant could replace missing elements. The amendments also provide a framework to assist entities in evaluating whether both an input and a substantive process are present. These amendments are effective for annual periods beginning after December 15, 2017, including interim periods within those periods, with early application permitted for transactions that have not been previously reported. We plan to adopt this guidance in the first quarter of 2018 and will apply the guidance prospectively to all new transactions.

Impairment of Goodwill

In January 2017, FASB issued ASU 2017-04, Intangibles—Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment, which eliminates Step 2 from the goodwill impairment test. Step 2 required entities to compute the implied fair value of goodwill if it was determined that the carrying amount of a reporting unit exceeded its fair value. Under the amendments in this update, an entity should perform its annual, or interim, goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount and should recognize an impairment charge for the amount by which the carrying amount exceeds the reporting unit's fair value. The goodwill impairment recognized should not exceed the total amount of goodwill attributed to that reporting unit. Additionally, an entity should consider income tax effects from any tax deductible goodwill on the carrying amount of the reporting unit when measuring the goodwill impairment loss, if applicable. An entity still has the option to perform the qualitative assessment for a reporting unit to determine if the quantitative impairment test is necessary. These amendments are effective for annual or any interim goodwill impairment tests in fiscal years beginning after December 15, 2019. Early adoption is permitted for interim or annual goodwill impairment tests performed on testing dates after January 1, 2017. We early adopted these amendments during the fourth quarter of 2017.

Other Income

In February 2017, FASB issued ASU 2017-05, Other Income—Gains and Losses from the Derecognition of Nonfinancial Assets (Subtopic 610-20), which clarifies the scope of Subtopic 610-20 and adds guidance for partial sales of nonfinancial assets. Specifically, the amendments clarify that the guidance applies to all nonfinancial assets and in substance nonfinancial assets unless other specific guidance applies and defines "in substance financial asset" as an asset or group of assets for which substantially all of the fair value consists of nonfinancial assets and the group or subsidiary is not a business. These amendments also impact the accounting for partial sales of nonfinancial assets, whereby an entity that transfers its controlling interest in a nonfinancial asset, but retains a noncontrolling ownership interest, will measure the retained interest at fair value resulting in the full gain/loss recognition upon sale. These amendments are effective for fiscal years, and interim periods within those years, beginning after December 15, 2017, with early adoption permitted. We plan to adopt this guidance on January 1, 2018, and expect no effect on our consolidated financial statements.

Stock Compensation – Scope of Modification Accounting

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

Financial Instruments with Down Round Features

In July 2017, FASB issued ASU 2017-11, Earnings Per Share (Topic 260); Distinguishing Liabilities from Equity (Topic 480); Derivatives and Hedging (Topic 815): (Part I) Accounting for Certain Financial Instruments with Down Round Features, (Part II) Replacement of the Indefinite Deferral for Mandatorily Redeemable Financial Instruments of Certain Nonpublic Entities and Certain Mandatorily Redeemable Noncontrolling Interests with a Scope Exception.

The amendments in this update are intended to simplify the accounting for certain equity-linked financial instruments and embedded features with down round features that result in the strike price being reduced on the basis of the pricing of future equity offerings. Under the new guidance, a down round feature will no longer need to be considered when determining whether certain financial instruments or embedded features should be classified as liabilities or equity instruments. That is, a down round feature will no longer preclude equity classification when assessing whether an instrument or embedded feature is indexed to an entity's own stock. In addition, the amendments clarify existing disclosure requirements for equity-classified instruments. These amendments are effective for fiscal years, and interim periods within those years, beginning after December 15, 2018, with early adoption permitted. We early adopted the applicable amendments in the second quarter of 2017 on a retrospective basis noting no effect on our consolidated financial statements.

Targeted Improvements to Accounting for Hedge Activities

In August 2017, FASB issued ASU 2017-12, Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedge Activities, which are intended to better align risk management activities and financial reporting for hedging relationships. The new guidance covers multiple aspects of hedge accounting: (1) changes the way in which ineffectiveness is accounted, (2) allows for new hedge strategies, and (3) changes hedge disclosures. Under the new guidance, companies will have the option to perform a qualitative quarterly effectiveness assessment once the initial quantitative test has been performed. In addition, any ineffectiveness that exists is required to be recorded in other comprehensive income instead of in earnings as is required under current guidance. Several new hedging strategies will be allowed to be given hedge accounting treatment, most of which involve the hedging of contractually specified components. Lastly, disclosure requirements will be updated to (1) require that hedge income be presented on the same line item as the related hedged item, (2) require hedge program objectives to be disclosed, and (3) eliminate the requirement to separately disclose ineffectiveness. These amendments are effective for fiscal years, and interim periods within those years, beginning after December 15, 2018, with early adoption permitted. We plan to adopt the applicable amendments in the first quarter of 2018 and expect an immaterial effect on our consolidated financial statements.

Note 4 – Acquisitions and Divestitures

2017 Acquisitions

Permian Acquisition

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

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

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

Delaware system. Since March 1, 2017, financial and statistical data of New Delaware have been included in Sand Hills operations.

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

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

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

The acquired businesses, 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 years ended December 31, 2017 and December 31, 2016 assumes that the Permian Acquisition occurred as of January 1, 2016. We prepared the following summarized unaudited pro forma financial results for comparative purposes only. The summarized unaudited pro forma information may not be indicative of the results that would have occurred had we completed this acquisition as of January 1, 2016, or that would be attained in the future.

	December 31,	
	2017 Pro Forma	2016 Pro Forma
Revenues	$8,829.0	$6,725.6
Net income (loss)	103.2	(195.4)

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. Pro forma net income for the year ended December 31, 2016 was adjusted to include those charges.

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

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

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

We accounted for the Permian Acquisition as an acquisition of a business under purchase accounting rules. The assets acquired and liabilities assumed related to the Permian Acquisition were recorded at their fair values as of the closing date of March 1, 2017. The fair 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. The goodwill is amortizable for tax purposes.

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

The valuation of the acquired assets and liabilities was prepared using fair value methods and assumptions including projections of future production volumes and cash flows, benchmark analysis of comparable public companies, expectations regarding customer contracts and relationships, and other management estimates. The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs, as defined in Note 17 – Fair Value Measurements. These inputs require significant judgments and estimates.

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

During the three months ended September 30, 2017, we finalized the purchase price allocation with no additional measurement period adjustments.

Contingent Consideration

A contingent consideration liability arising from potential earn-out payments in connection with the Permian Acquisition has been recognized at its fair value. We agreed to pay up to an additional $935.0 million in potential earn-out payments that would occur in 2018 and 2019. The acquisition date fair value of the potential earn-out payments of $416.3 million was recorded within Other long-term liabilities on our Consolidated Balance Sheets. Changes in the fair value of this liability (that were not accounted for as revisions of the acquisition date fair value) are included in earnings. During the year ended December 31, 2017, we recognized $99.3 million as Other income related to the change in fair value of the contingent consideration. See Note 11 – Other Long-term Liabilities and Note 17 – Fair Value Measurements for additional discussion of the change in fair value and the fair value methodology.

As of December 31, 2017, the fair value of the first potential earn-out payment of $6.8 million has been recorded as a component of Accounts payable and accrued liabilities, which are included within current liabilities on our Consolidated Balance Sheets. As of December 31, 2017, the fair value of the second potential earn-out payment of $310.2 million has been recorded within Other long-term liabilities on our Consolidated Balance Sheets.

Flag City Acquisition

On May 9, 2017, we purchased all of the equity interests in Flag City Processing Partners, LLC ("FCCP") from Boardwalk Midstream, LLC (“Boardwalk”) and all of the equity interests in FCPP Pipeline, LLC from Boardwalk Field Services, LLC (“BFS”) for a base purchase price of $60.0 million subject to customary closing adjustments. The 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.

The gas processing activities under the Flag City Plant contracts have been redirected to our Silver Oak Plants. We have shut down the Flag City Plant and are moving the plant and its component parts to other Targa locations. In December 2017, ownership of the Flag City plant assets was transferred to Centrahoma Processing, LLC (“Centrahoma”), a joint venture that we operate, and in which we have a 60% ownership interest. The remaining 40% ownership interest in Centrahoma is held by MPLX, LP. In conjunction with the transfer of the plant assets, MPLX, LP made a cash contribution to Centrahoma in order to maintain its 40% ownership interest. Centrahoma is a consolidated subsidiary. The Flag City plant assets will be relocated to, and installed in, Hughes County, Oklahoma, in 2018, and will be renamed the Hickory Hills Plant. The Hickory Hills Plant will process growing natural gas production from the Arkoma Woodford Basin and is expected to begin operations in the fourth quarter of 2018.

We accounted for this purchase as an asset acquisition and have capitalized less than $0.1 million of acquisition related costs as a component of the cost of assets acquired, which resulted in 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.

Purchase of Outstanding Silver Oak II Interest

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

2016 Acquisition

Purchase of Outstanding Versado Membership Interest

On October 31, 2016, we executed a Membership Interest Sale and Purchase Agreement with Chevron U.S.A. Inc. to acquire the remaining 37% membership interest in our consolidated subsidiary Versado Gas Processors, L.L.C. (“Versado”). As we continue to control Versado, the change in our ownership interest was accounted for as an equity transaction representing the acquisition of a noncontrolling interest and no gain or loss was recognized in our Consolidated Statements of Operations.

2015 Acquisition

Atlas Mergers

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

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

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

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

On February 27, 2015, the Partnership's partnership agreement (the "Partnership Agreement') was amended to provide for the issuance of the Special GP Interest representing the contribution to the Partnership of the APL GP interest acquired in the ATLS merger totaling $1.6 billion, which is reflected within Additional paid-in capital on the Consolidated Balance Sheets. The Special GP Interest is not entitled to current distributions or allocations of net income or loss, and has no voting rights or other rights except for the limited right to receive deductions attributable to the contribution of APL GP and the right to distributions in liquidation. On December 1, 2016, the Special GP Interest was eliminated with an amendment to the Partnership Agreement. See Note 14 – Partnership Units and Related Matters.

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

Pursuant to the APL Merger Agreement, Targa agreed to cause the general partner of the Partnership to amend the Partnership Agreement, which we refer to as the "IDR Giveback Amendment", in order to reduce aggregate distributions to us, as the holder of the Partnership's IDRs, by (a) $9,375,000 per quarter during the first four quarters following the APL merger, (b) $6,250,000 per quarter for the next four quarters, (c) $2,500,000 per quarter for the next four quarters and (d) $1,250,000 per quarter for the next four quarters, with the amount of such reductions to be distributed pro rata to the holders of the Partnership's outstanding common units. On December 1, 2016, the IDRs were eliminated with an amendment to the Partnership Agreement (see Note 14 – Partnership Units and Related Matters) and the reallocations of IDRs under the IDR Giveback Amendment ceased in the fourth quarter of 2016.

The APL merger was a unit-for-unit transaction with an exchange ratio of 0.5846 of the Partnership's common units (the "APL Unit Consideration") and $1.26 in cash for each APL common unit (the "APL Cash Consideration" and, with the APL Unit Consideration, the "APL Merger Consideration"), a $128.0 million total cash payment, of which $0.6 million was expensed at the acquisition date as the cash payment representing accelerated vesting of a portion of retained employees' APL phantom awards. The Partnership issued 58,614,157 of its common units and awarded 629,231 replacement phantom unit awards with a combined value of approximately $2.6 billion as consideration for the APL merger (based on the $43.82 closing market price of a common unit on the NYSE on February 27, 2015). The cash component of the APL merger also included $701.4 million for the mandatory repayment and extinguishment at closing of the APL Senior Secured Revolving Credit Facility that was to mature in May 2017 (the "APL Revolver"), $28.8 million of payments related to change of control and $6.4 million of cash paid in lieu of unit issuances in connection with settlement of APL equity awards for AEG employees. In March 2015, we contributed $52.4 million to the Partnership to maintain our 2% general partner interest.

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

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

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

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

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

The acquired business contributed revenues of $1,459.3 million and a net loss of $30.1 million to the Company for the period from February 27, 2015 to December 31, 2015, and is reported in our Gathering and Processing segment. Cumulative acquisition-related costs totaled $27.3 million. These expenses are included in other expense in our Consolidated Statements of Operations.

Pro Forma Impact of Atlas Mergers on Consolidated Statement of Operations

The following summarized unaudited pro forma Consolidated Statement of Operations information for the year ended December 31, 2015 assumes that the Partnership’s acquisition of APL and our acquisition of ATLS had occurred as of January 1, 2014. We prepared the following summarized unaudited pro forma financial results for comparative purposes only. The summarized unaudited pro forma financial results may not be indicative of the results that would have occurred if we had completed these acquisitions as of January 1, 2014, or that the results that will be attained in the future. Amounts presented below are in millions.

	December 31, 2015 Pro Forma
Revenues	$ 6,947.3
Net income	(169.6)

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

- Reflect the change in amortization expense resulting from the difference between the historical balances of APL's intangible assets, net, and the fair value of intangible assets acquired.
- Reflect the change in depreciation expense resulting from the difference between the historical balances of APL's property, plant and equipment, net, and the fair value of property, plant and equipment acquired.
- Reflect the change in interest expense resulting from our financing activities directly related to the Atlas mergers as compared to APL's historical interest expense.
- Reflect the changes in stock-based compensation expense related to the fair value of the unvested portion of replacement Partnership Long Term Incentive Plan ("LTIP") awards that were issued in connection with the acquisition to APL phantom unitholders who continue to provide service as Targa employees following the completion of the APL merger.
- Remove the results of operations attributable to the February 2015 transfer to Atlas Resource Partners, L.P. of 100% of APL's interest in gas gathering assets located in the Appalachian Basin of Tennessee.

- Exclude $27.3 million of acquisition-related costs incurred as of December 31, 2015 from pro forma net income for the year ended December 31, 2015.
- Reflect the change in APL's revenues and product purchases to report plant sales of Y-grade at contractual net values to conform to our accounting policy.

The following table summarizes the consideration transferred to acquire ATLS and APL, which are viewed together as a single integrated transaction for GAAP reporting purposes:

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

(1) Net of cash acquired of $40.8 million.
(2) The fair value of consideration transferred in the form of replacement restricted stock unit awards and replacement phantom unit awards represent the allocation of the fair value of the awards to the pre-combination service period. The fair value of the awards associated with the post-combination service period will be recognized over the remaining service period of the award.

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

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

The valuation of the acquired assets and liabilities was prepared using fair value methods and assumptions including projections of future production volumes and cash flows, benchmark analysis of comparable public companies, expectations regarding customer contracts and relationships, and other management estimates. The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs, as defined in Note 17 – Fair Value Measurements. These inputs require significant judgments and estimates at the time of valuation.

The excess of the fair value of the consideration transferred over the fair value of net assets acquired was approximately $707.0 million, which was recorded as goodwill. The determination of goodwill is attributable to the workforce of the acquired business and the expected synergies. Goodwill was attributed to the WestTX, SouthTX and SouthOK reporting units in our Gathering and Processing segment. The goodwill is amortizable over 15 years for tax purposes. See Note 7 – Goodwill.

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

Mandatorily Redeemable Preferred Interests

Other long-term liabilities acquired included $109.3 million related to mandatorily redeemable preferred interests held by our partner in two joint ventures. See Note 11 – Other Long-Term Liabilities.

Contingent Consideration

A liability arising from the contingent consideration for APL's previous acquisition of a gas gathering system and related assets has been recognized at fair value. APL agreed to pay up to an additional $6.0 million if certain volumes are achieved on the acquired gathering system within a specified time period. The acquisition date fair value of the remaining contingent payment of $4.2 million was recorded within other long term liabilities on our Consolidated Balance Sheets. Subsequent changes in the fair value of this liability are included in earnings.

Replacement Restricted Stock Units ("RSUs")

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

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

The fair value of the RSUs was based on the closing price of our common shares at the close of trading on February 27, 2015. The fair value was allocated between the pre-acquisition and post-acquisition periods to determine the amount to be treated as purchase consideration and future compensation expense, respectively. Compensation cost will be recognized in general and administrative expense over the remaining service period of each award. See Note 25 – Compensation Plans for discussion of the impact of the TRC/TRP Merger on the replacement RSUs.

Replacement Phantom Units

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

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

The fair value of the replacement phantom units was based on the closing price of the Partnership's units at the close of trading on February 27, 2015. The fair value was allocated between the pre-acquisition and post-acquisition periods to determine the amount to be treated as purchase consideration and compensation expense, respectively. Compensation cost will be recognized in general and administrative expense over the remaining service period of each award. See Note 25 – Compensation Plans for discussion of the impact of the TRC/TRP Merger on the replacement phantom units.

2017 Divestiture

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

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

2017 Joint Venture

Grand Prix Joint Venture

In May 2017, we announced plans to construct Grand Prix, a new common carrier NGL pipeline. Grand Prix will transport volumes from the Permian Basin and our North Texas system to our fractionation and storage complex in the NGL market hub at Mont Belvieu, Texas. Grand Prix will be supported by our volumes and other third party customer commitments, and is expected to be in service in the second quarter of 2019. The capacity of the pipeline from the Permian Basin will be approximately 300 MBbl/d, expandable to 550 MBbl/d.

In September 2017, we sold a 25% interest in our consolidated subsidiary, Grand Prix Pipeline LLC (the “Grand Prix Joint Venture”) to funds managed by Blackstone Energy Partners ("Blackstone"). We are the operator and construction manager of Grand Prix. Our share of total growth capital expenditures for Grand Prix is expected to be approximately $728 million, which includes the impact of the DevCo JVs agreements (see Note 2 – Basis of Presentation).

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

Subsequent Event

In January 2018, we announced that we will contribute our Tupelo Plant, a 120 MMcf/d natural gas processing plant in Coal County, Oklahoma, to Centrahoma, upon the in-service date of the Hickory Hills Plant. We will maintain our 60% ownership interest in the expanded joint venture and receive a cash distribution in exchange for our contribution of assets. MPLX, LP will contribute cash to Centrahoma to maintain its 40% ownership interest.

Note 5 — Inventories

	December 31, 2017	December 31, 2016
Commodities	$ 191.6	$ 126.9
Materials and supplies	12.9	10.8
	$ 204.5	$ 137.7

Note 6 — Property, Plant and Equipment and Intangible Assets

Property, Plant and Equipment

	December 31, 2017	December 31, 2016	Estimated Useful Lives (In Years)
Gathering systems	$ 7,037.2	$ 6,626.8	5 to 20
Processing and fractionation facilities	3,569.6	3,390.2	5 to 25
Terminaling and storage facilities	1,244.1	1,205.0	5 to 25
Transportation assets	343.6	451.4	10 to 25
Other property, plant and equipment	303.7	274.2	3 to 25
Land	125.7	121.3	—
Construction in progress	1,581.5	449.8	—
Property, plant and equipment	14,205.4	12,518.7	
Accumulated depreciation	(3,775.4)	(2,827.7)	
Property, plant and equipment, net	$ 10,430.0	$ 9,691.0	
Intangible assets	$ 2,736.6	$ 2,036.6	10 to 20
Accumulated amortization	(570.8)	(382.6)	
Intangible assets, net	$ 2,165.8	$ 1,654.0	

For each of the years ended December 31, 2017, 2016, and 2015 depreciation expense was $621.3 million, $601.5 million and $507.8 million.

2017 Impairment of North Texas Gathering and Processing Assets

We recorded a non-cash pre-tax impairment charge of $378.0 million in the third quarter of 2017 for the partial impairment of gas processing facilities and gathering systems associated with our North Texas operations in our Gathering and Processing segment. The impairment was 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. Underlying our assessment was the expected continuing decline in natural gas production across the Barnett Shale in North Texas due in part to producers pursuing more attractive opportunities in other basins. We measured the impairment of property, plant and equipment using discounted estimated future cash flow analysis (“DCF”) including a terminal value (a Level 3 fair value measurement). The future cash flows were based on our estimates of future revenues, income from operations and other factors, such as timing of capital expenditures. 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.

2015 Impairment of Louisiana Gathering and Processing Assets

We recorded non-cash pre-tax impairment charges of $32.6 million in 2015 due to the impairment of certain gas processing facilities and gathering systems associated with our Coastal and Big Lake operations. The impairments were a result of reduced forecasted gas processing volumes due to market conditions and processing spreads in Louisiana in the fourth quarter of 2015. We measured the impairment of property, plant and equipment using discounted estimated future cash flows representative of a Level 3 fair value measurement. These carrying value adjustments are 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 the Permian and Flag City Acquisitions in 2017, the mergers with ATLS and APL in 2015 (collectively, the “Atlas mergers”) and our Badlands acquisition in 2012. The fair values of these acquired intangible assets were determined at the date of acquisition based on the present values of estimated future cash flows. Key valuation assumptions include probability of contracts under negotiation, renewals of existing contracts, economic incentives to retain customers, past and future volumes, current and future capacity of the gathering system, pricing volatility and the discount rate. Amortization expense attributable to these assets is recorded over the periods in which we benefit from services provided to customers.

The intangible assets acquired in the Permian Acquisition were recorded at a fair value of $692.3 million. We are amortizing these intangible assets over a 15-year life using the straight-line method, as a reliably determinable pattern of amortization could not be identified.

The intangible assets acquired in the Flag City Acquisition were recorded at a fair value of $7.7 million. We are amortizing these intangible assets over a 10-year life using the straight-line method, as a reliably determinable pattern of amortization could not be identified.

The intangible assets acquired in the Atlas mergers were recorded at a fair value of $1,354.9 million. We are amortizing these intangible assets over a 20-year life using the straight-line method, as a reliably determinable pattern of amortization could not be identified.

The intangible assets acquired in the Badlands acquisition were recorded at a fair value of $679.6 million. Amortization expense attributable to these intangible assets is recorded using a method that closely reflects the cash flow pattern underlying the intangible asset valuation over a 20-year life.

For each of the years ended December 31, 2017, 2016, and 2015 amortization expense for our intangible assets was $188.2 million, $156.1 million and $136.7 million. The estimated annual amortization expense for intangible assets is approximately $182.6 million, $171.6 million, $159.4 million, $149.5 million and $141.2 million for each of the years 2018 through 2022. As of December 31, 2017 the weighted average amortization period for our intangible assets was approximately 15.9 years.

The changes in our intangible assets are as follows:

	December 31, 2017	December 31, 2016
Beginning of period	$ 1,654.0	$ 1,810.1
Additions from Permian Acquisition	692.3	—
Additions from Flag City Acquisition	7.7	—
Amortization	(188.2)	(156.1)
End of period	$ 2,165.8	$ 1,654.0

Note 7 – Goodwill

We recognized goodwill of approximately $707.0 million when we acquired Atlas on February 27, 2015. This goodwill was attributed to the WestTX, SouthTX and SouthOK reporting units in our Gathering and Processing segment. We also recognized goodwill of approximately $46.6 million related to the Permian Acquisition on March 1, 2017. This goodwill was attributed to the New Midland and New Delaware reporting units in our Gathering and Processing segment.

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 discounted cash flow (“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 17 – Fair Value Measurements. These inputs require significant judgments and estimates at the time of valuation.

2015 Goodwill Assessment

As of December 31, 2015, we had not completed our November 30, 2015 impairment assessment of the goodwill resulting from the February 2015 Atlas Acquisitions. Based on the results of that preliminary evaluation, we recorded a provisional goodwill impairment of $290.0 million in our Consolidated Statements of Operations during the fourth quarter of 2015.

During the first quarter of 2016, we finalized our 2015 impairment assessment and recorded additional impairment expense of $24.0 million in our Consolidated Statements of Operations. The impairment of goodwill was primarily due to the effects of lower commodity prices, and a higher cost of capital for companies in our industry compared to conditions in February 2015 when we acquired Atlas.

2016 Goodwill Assessment

Our 2016 annual evaluation of goodwill for impairment was completed in the fourth quarter of 2016. Due to the impact of lower forecasted commodity prices and a refinement in the valuation methodology used to determine fair values of our reporting units, we recorded impairment expense of $183.0 million in our Consolidated Statements of Operations.

2017 Goodwill Assessment

We did not record any goodwill impairment charges for the year ended December 31, 2017, as the fair values of all reporting units exceeded their accounting carrying values. The future cash flow estimates from the DCF analysis have increased since the last time an annual goodwill impairment assessment was performed due to the favorable effects of current and expected industry and market conditions, including future commodity prices and expected volumetric forecasts. We determined that the fair value of our WestTX reporting unit exceeded its carrying amount at November 30, 2017, but not by a substantial amount. As the reporting unit fair values are sensitive to changes in certain assumptions, there is a possibility that declines in commodity prices, drilling activity and resulting producer volumes, or market multiples, or increases in cost of capital could result in the impairment of goodwill.

Changes in the net amounts of our goodwill are as follows:

	WestTX	SouthTX	SouthOK	Permian (1)	Total
Balance at January 1, 2015	$—	$—	$—	$—	$—
Acquisition, February 27, 2015	364.5	160.3	182.2	—	707.0
Provisional impairment for 2015 annual assessment	(37.6)	(70.2)	(182.2)	—	(290.0)
Balance at December 31, 2015, net	326.9	90.1	—	—	417.0
Additional impairment for 2015 annual assessment	(14.4)	(9.6)	—	—	(24.0)
Impairment for 2016 annual assessment	(137.8)	(45.2)	—	—	(183.0)
Balance at December 31, 2016, net	174.7	35.3	—	—	210.0
Permian Acquisition, March 1, 2017	—	—	—	46.6	46.6
Balance at December 31, 2017, net	$ 174.7	$ 35.3	$—	$ 46.6	$ 256.6

(1) Permian column includes net amounts of goodwill of $23.2 million for the New Midland reporting unit and $23.4 million for the New Delaware reporting unit.

Note 8 – Investments in Unconsolidated Affiliates

Our investments in unconsolidated affiliates consist of the following:

- a 38.8% non-operated ownership interest in Gulf Coast Fractionators LP ("GCF");
- three non-operated joint ventures in South Texas acquired in the Atlas mergers in 2015: a 75% interest in T2 LaSalle, a gas gathering company; a 50% interest in T2 Eagle Ford, a gas gathering company; and a 50% interest in T2 EF Cogen ("Cogen"), which owns a cogeneration facility, (together the "T2 Joint Ventures");
- a 50% operated ownership interest in Cayenne Pipeline, LLC ("Cayenne Joint Venture"); and
- a 25% non-operated ownership interest in GCX.

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

The T2 Joint Ventures were formed to provide services for the benefit of their joint interest owners. The T2 LaSalle and T2 Eagle Ford gathering companies have capacity lease agreements with their joint interest owners, which cover costs of operations (excluding depreciation and amortization).

In July 2017, we entered into the Cayenne Joint Venture with American Midstream LLC to convert an existing 62-mile gas pipeline to an NGL pipeline connecting the VESCO plant in Venice, Louisiana, to the Enterprise Products Operating LLC ("Enterprise") pipeline at Toca, Louisiana, for delivery to Enterprise's Norco Fractionator. We acquired a 50% interest in the Cayenne Joint Venture for $5.0 million. The project commenced operations in December 2017.

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

	GCF	T2 LaSalle	T2 Eagle Ford	T2 EF Cogen	Cayenne	Total
Balance at December 31, 2014	$50.2	$ —	$—	$—	$ —	$50.2
Fair value of T2 Joint Ventures acquired	—	67.5	126.7	20.3	—	214.5
Equity earnings (loss)	13.8	(3.9)	(9.4)	(3.0)	—	(2.5)
Cash distributions (1)	(14.5)	—	—	(0.5)	—	(15.0)
Cash calls for expansion projects	—	—	6.5	5.2	—	11.7
Balance at December 31, 2015	$49.5	$ 63.6	$123.8	$22.0	$ —	$258.9
Equity earnings (loss)	4.1	(5.2)	(9.4)	(3.8)	—	(14.3)
Cash distributions (1)	(7.5)	—	—	(0.7)	—	(8.2)
Cash calls for expansion projects	—	0.2	4.2	—	—	4.4
Balance at December 31, 2016	$46.1	$ 58.6	$118.6	$17.5	$ —	$240.8
Equity earnings (loss)	12.4	(4.9)	(10.6)	(13.9)	—	(17.0)
Cash distributions (1)	(12.7)	—	—	—	—	(12.7)
Acquisition	—	—	—	—	5.0	5.0
Contributions (2)	—	0.4	1.2	0.3	3.6	5.5
Balance at December 31, 2017	$45.8	$ 54.1	$109.2	$3.9	$ 8.6	$221.6

(1) Includes $0.2 million, $4.1 million and $1.2 million in distributions received from GCF and the T2 Joint Ventures in excess of our share of cumulative earnings for the years ended December 31, 2017, 2016 and 2015. Such excess distributions are considered a return of capital and disclosed in cash flows from investing activities in our Consolidated Statements of Cash Flows.

(2) Includes a $1.0 million contribution of property, plant and equipment to T2 Eagle Ford.

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 have determined that factors indicate that a decrease in the value of our investment occurred that was other than temporary. As a result of this evaluation, we recorded an impairment loss of approximately $12.0 million in the first quarter of 2017, which represented our proportionate share (50%) of an impairment charge recorded by the joint venture, as well as our impairment of the unamortized excess fair value resulting from the Atlas mergers.

The carrying values of the T2 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, 2017, $26.2 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. See Note 4 – Acquisitions and Divestitures for further information regarding the fair value determinations related to the

Atlas mergers.

Gulf Coast Express Joint Venture

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

Subsequent Events

In January 2018, we contributed $69.3 million to the Gulf Coast Express Joint Venture.

In January 2018, we announced the formation of a 50/50 joint venture with Hess Midstream Partners LP to construct a new 200 MMcf/d natural gas processing plant ("LM4 Plant") at Targa's existing Little Missouri facility. The total cost of the LM4 Plant is expected to be approximately $150 million and the plant is anticipated to be completed in the fourth quarter of 2018. Targa will manage construction of, and operate, the LM4 Plant.

Note 9 — Accounts Payable and Accrued Liabilities

	December 31, 2017	December 31, 2016
Commodities	$ 711.5	$ 574.4
Other goods and services	289.7	117.0
Interest	54.4	52.3
Income and other taxes	27.1	24.2
Permian Acquisition contingent consideration, estimated current portion	6.8	—
Compensation and benefits	52.8	37.2
Preferred Series A dividends payable	22.9	22.9
Other	21.7	15.5
	$ 1,186.9	$ 843.5

Accounts payable and accrued liabilities includes $50.4 million and $30.5 million of liabilities to creditors to whom we have issued checks that remain outstanding as of December 31, 2017 and December 31, 2016. The estimated current portion of the Permian Acquisition contingent consideration represents the fair value as of December 31, 2017 of the first potential earn-out payment that would be payable in May 2018. The estimated remaining portion would be payable in May 2019 and is recorded within Other long-term liabilities on our Consolidated Balance Sheets.

Note 10 — Debt Obligations

	December 31, 2017	December 31, 2016
Current:		
Obligations of the Partnership: (1)		
Accounts receivable securitization facility, due December 2018	$ 350.0	$ 275.0
Long-term:		
TRC obligations:		
TRC Senior secured revolving credit facility, variable rate, due February 2020 (2)	435.0	275.0
TRC Senior secured term loan, variable rate, due February 2022	—	160.0
Unamortized discount	—	(2.2)
Obligations of the Partnership: (1)		
Senior secured revolving credit facility, variable rate, due October 2020 (3)	20.0	150.0
Senior unsecured notes:		
5% fixed rate, due January 2018	—	250.5
4 % fixed rate, due November 2019	749.4	749.4
6 % fixed rate, due August 2022	—	278.7
5¼% fixed rate, due May 2023	559.6	559.6
4¼% fixed rate, due November 2023	583.9	583.9
6¾% fixed rate, due March 2024	580.1	580.1
5 % fixed rate, due February 2025	500.0	500.0
5 % fixed rate, due February 2027	500.0	500.0
5% fixed rate, due January 2028	750.0	—
TPL notes, 4¾% fixed rate, due November 2021	6.5	6.5
TPL notes, 5 % fixed rate, due August 2023	48.1	48.1
Unamortized premium	0.4	0.5
	4,733.0	4,640.1
Debt issuance costs, net of amortization	(30.0)	(34.1)
Long-term debt	4,703.0	4,606.0
Total debt obligations	$ 5,053.0	$ 4,881.0
Irrevocable standby letters of credit:		
Letters of credit outstanding under the TRC Senior secured credit facility (2)	$ —	$ —
Letters of credit outstanding under the Partnership senior secured revolving credit facility (3)	27.2	13.2
	$ 27.2	$ 13.2

(1)

While we consolidate the debt of the Partnership in our financial statements, we do not have the obligation to make interest payments or debt payments with respect to the debt of the Partnership.

(2) As of December 31, 2017, availability under TRC’s $670.0 million senior secured revolving credit facility (“TRC Revolver”) was $235.0 million.

(3) As of December 31, 2017, availability under the Partnership’s $1.6 billion senior secured revolving credit facility (“TRP Revolver”) was $1,552.8 million.

The following table shows the contractually scheduled maturities of our debt obligations outstanding at December 31, 2017, for the next five years, and in total thereafter:

	Scheduled Maturities of Debt						
	Total	2018	2019	2020	2021	2022	After 2022
	(in millions)						
TRC Senior secured revolving credit facility	$ 435.0	$ —	$ —	$ 435.0	$ —	$ —	$ —
TRP Revolver	20.0	—	—	20.0	—	—	—
Partnership's Senior unsecured notes	4,277.6	—	749.4	—	6.5	—	3,521.7
Partnership's accounts receivable securitization facility	350.0	350.0	—	—	—	—	—
Total	$ 5,082.6	$ 350.0	$ 749.4	$ 455.0	$ 6.5	$ —	$ 3,521.7

The following table shows the range of interest rates and weighted average interest rate incurred on variable-rate debt obligations during the year ended December 31, 2017:

	Range of Interest Rates Incurred	Weighted Average Interest Rate Incurred
TRC Revolver	2.5% - 4.5%	2.9%
TRC Senior secured term loan (1)	5.75%	5.75%
TRP Revolver	3.0% - 5.3%	3.2%
Partnership's accounts receivable securitization facility	1.8% - 2.6%	2.1%

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

Compliance with Debt Covenants

As of December 31, 2017, we were in compliance with the covenants contained in our various debt agreements.

Debt Obligations

TRC Credit Agreement

In connection with the closing of the Atlas mergers, we entered into a Credit Agreement (the “TRC Credit Agreement”), dated as of February 27, 2015, among us, each lender from time to time party thereto and Bank of America, N.A. as administrative agent, collateral agent, swing line lender and letter of credit issuer.

The TRC Credit Agreement provides for a five year revolving credit facility that is due February 27, 2020 in an aggregate principal amount up to $670.0 million that allows us to request up to $200.0 million in additional commitments, and a seven-year variable rate term loan facility in an aggregate principal amount of $430 million. This facility was issued at a 1.75% discount. The term loan is a Eurodollar rate loan with an interest rate of LIBOR (with a LIBOR floor of 1%) plus an applicable rate of 4.75%. We used the net proceeds from the term loan issuance and the revolving credit facility to fund cash components of the ATLS merger, including cash merger consideration and approximately $160.2 million related to change of control payments made by ATLS, cash settlements of equity awards and transaction fees and expenses.

We are required to pay a commitment fee ranging from 0.375% to 0.5% (dependent upon the Company's consolidated leverage ratio) on the daily average unused portion of the TRC Revolver. Additionally, outstanding borrowings bear interest at an applicable rate ranging from 1.75% to 2.75% (dependent upon the Company's consolidated leverage ratio).

The TRC Credit Agreement is secured by substantially all of the Company's assets. The TRC Credit Agreement requires us to maintain a consolidated leverage ratio (the ratio of consolidated funded indebtedness to consolidated adjusted EBITDA) of no more than (i) 4.50 to 1.00 for the fiscal quarter ending March 31, 2016 through the fiscal quarter ending December 31, 2016 and (ii) 4.00 to 1.00 for each fiscal quarter ending thereafter. The TRC Credit Agreement restricts our ability to pay dividends to shareholders if, on a pro forma basis after giving effect to such dividend, (a) any default or event of default has occurred and is continuing or (b) we are not in compliance with our consolidated leverage ratio as of the last day of the most recent test period. In addition, the TRC Credit Agreement includes 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.

The Partnership's Revolving Credit Facility

In October 2016, the Partnership entered into the Second Amendment and Restatement Agreement (the "Restatement") to effectuate the Third Amended and Restated Credit Agreement (the "TRP Credit Agreement"). The TRP Credit Agreement amended and restated the TRP Revolver to extend the maturity date from October 2017 to October 2020. The available commitments under the TRP Revolver of $1.6 billion remained unchanged while the Partnership's ability to request additional commitments increased from up to $300.0 million to up to $500.0 million.

The TRP Credit Agreement designates TPL and certain of its subsidiaries as Restricted Subsidiaries and 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. As a result of the TRP Credit Agreement, during the fourth quarter of 2016, we recorded a partial write-off of $0.9 million of debt issuance costs associated with the TRP Revolver as a result of a change in syndicate members under the TRP Revolver. The remaining debt issuance costs associated with the TRP Revolver along with debt issuance costs incurred with this amendment will be amortized on a straight-line basis over the life of the TRP Revolver.

In 2015, the Partnership used proceeds from borrowings under the TRP Revolver to fund some of the cash components of the APL merger, including $701.4 million for the repayments of the APL Revolver and $28.8 million related to change of control payments.

The TRP Revolver bears interest, at the Partnership's option, either at the base rate or the Eurodollar rate. The base rate is equal to the highest of: (i) Bank of America's prime rate; (ii) the federal funds rate plus 0.5%; or (iii) the one-month LIBOR rate plus 1.0%, plus an applicable margin ranging from 0.75% to 1.75% (dependent on the Partnership's ratio of consolidated funded indebtedness to consolidated adjusted EBITDA). The Eurodollar rate is equal to LIBOR rate plus an applicable margin ranging from 1.75% to 2.75% (dependent on the Partnership's ratio of consolidated funded indebtedness to consolidated adjusted EBITDA).

The Partnership is required to pay a commitment fee equal to an applicable rate ranging from 0.3% to 0.5% (dependent on the Partnership's ratio of consolidated funded indebtedness to consolidated adjusted EBITDA) times the actual daily average unused portion of the TRP Revolver. Additionally, issued and undrawn letters of credit bear interest at an applicable rate ranging from 1.75% to 2.75% (dependent on the Partnership's ratio of consolidated funded indebtedness to consolidated adjusted EBITDA).

The TRP Revolver is collateralized by a pledge of assets and equity from certain of the Partnership's subsidiaries. Borrowings are guaranteed by the Partnership's restricted subsidiaries.

The TRP Revolver restricts the Partnership's 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. The TRP Revolver requires the Partnership to maintain a ratio of consolidated funded indebtedness to consolidated adjusted EBITDA of no more than 5.50 to 1.00. The TRP Revolver also requires the Partnership to maintain a ratio of consolidated adjusted EBITDA to consolidated interest expense of no less than 2.25 to 1.00. In addition, the TRP Revolver contains various covenants that may limit, among other things, the Partnership's 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 the Partnership's right to incur indebtedness or grant liens in connection with, and convey accounts receivable as part of, a permitted receivables financing).

The Partnership's Accounts Receivable Securitization Facility

On February 23, 2017, we amended the Partnership's accounts receivable securitization facility to increase the facility size from $275.0 million to $350.0 million. On December 8, 2017, we renewed and extended the Partnership's Securitization Facility with termination date of December 7, 2018.

The Securitization Facility provides up to $350.0 million of borrowing capacity at LIBOR market index rates plus a margin through December 7, 2018. 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. As of December 31, 2017, total funding under the Securitization Facility was $350.0 million.

The Partnership’s Senior Unsecured Notes

All issues of unsecured senior notes are pari passu with existing and future senior indebtedness, including indebtedness under the TRP Revolver. They are senior in right of payment to any of our future subordinated indebtedness and are unconditionally guaranteed by the Partnership and the Partnership’s restricted subsidiaries. These notes are effectively subordinated to all secured indebtedness under the TRP Revolver and the Partnership’s 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.

The Partnership’s senior unsecured notes and associated indenture agreements restrict the Partnership’s ability to make distributions to unitholders in the event of default (as defined in the indentures). The indentures also restrict the Partnership’s ability and the ability of certain of its 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.

The Partnership may redeem up to 35% of the aggregate principal amount of the notes in the table below at the redemption dates and prices set forth below (expressed as percentages of principal amounts) plus accrued and unpaid interest and liquidation damages, if any, 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.

Note Issue	Any Date Prior To	Price
6 ¾% Senior Notes	September 15, 2018	106.750%
5 % Senior Notes	February 1, 2020	105.125%
5 % Senior Notes	February 1, 2020	105.375%
5% Senior Notes	January 15, 2021	105.000%

The Partnership may also redeem all or part of each of the series of notes on or after the redemption dates set forth below at the price for each respective year (expressed as percentages of principal amount) plus accrued and unpaid interest and liquidation damages, if any, on the notes redeemed.

Note	Redemption Date	Year	Price
4 % Senior Notes	November 15	2017	101.031%
		2018 and thereafter	100 %
5 ¼% Senior Notes	November 1	2017	102.625%
		2018	101.750%
		2019	100.875%
		2020 and thereafter	100 %
4 ¼% Senior Notes	May 15	2018	102.125%
		2019	101.417%
		2020	100.708%
		2021 and thereafter	100 %
6 ¾% Senior Notes	September 15	2019	103.375%
		2020	101.688%
		2021 and thereafter	100 %
5 % Senior Notes	February 1	2020	103.844%
		2021	102.563%
		2022	101.281%
		2023 and thereafter	100 %
5 % Senior Notes	February 1	2022	102.688%
		2023	101.792%
		2024	100.896%
		2025 and thereafter	100 %
5% Senior Notes	January 15	2023	102.500%
		2024	101.667%
		2025	100.833%
		2026 and thereafter	100 %
TPL 4 ¾% Notes	May 15	2017	102.375%
		2018	101.188%
		2019 and thereafter	100 %
TPL 5 % Notes	February 1	2018	102.938%
		2019	101.958%
		2020	100.979%
		2021 and thereafter	100 %

Senior Notes Issuances

In January 2015, the Partnership and Targa Resources Partners Finance Corporation (collectively, the “Partnership Issuers”) issued $1.1 billion in aggregate principal amount of 5% Senior Notes due 2018 (the “5% Senior Notes”). The 5% Senior Notes resulted in approximately $1,089.8 million of net proceeds after costs, which were used with borrowings under the TRP Revolver to fund the TPL Notes Tender Offers and the Change of Control Offer (each as defined below). The 5% Senior Notes are unsecured senior obligations that have substantially the same terms and covenants as the Partnership’s other senior notes.

In September 2015, the Partnership Issuers issued $600 million in aggregate principal amount of 6¾% Senior Notes due 2024 (the “6¾% Senior Notes”). The 6¾% Senior Notes resulted in approximately $595.0 million of net proceeds after costs, which were used to reduce borrowings under the TRP Revolver and for general partnership purposes. The 6¾% Senior Notes are unsecured senior obligations that have substantially the same terms and covenants as the Partnership’s other senior notes.

In October 2016, the Partnership Issuers issued $500.0 million of 5 % Senior Notes due February 2025 and $500.0 million of 5 % Senior Notes due February 2027 (collectively, the “2016 Senior Notes”), yielding net proceeds after costs of approximately $496.2 million and $496.2 million respectively. The 2016 Senior Notes have substantially similar terms and covenants as our other series of Senior Notes. The net proceeds from the offering of the 2016 Senior Notes (the “October 2016 Offering”), along with borrowings under the TRP Revolver were used to fund concurrent tender offers for certain other series of senior notes and to fund redemption payments for certain note balances remaining after the tender offers. See “Debt Repurchases and Extinguishments” for further details of the concurrent tender offers.

In October 2017, the Partnership issued $750.0 million aggregate principal amount of 5% senior notes due January 2028 (the “5% Senior Notes due 2028”). The Partnership used the net proceeds of $744.1 million after costs from this offering to redeem its 5% Senior Notes, reduce borrowings under its credit facilities, and for general partnership purposes.

Shelf Registrations

The Partnership’s April 2015 Shelf

In April 2015, the Partnership filed with the SEC a universal shelf registration statement that allows it to issue up to an aggregate of $1.0 billion of debt or equity securities (the “April 2015 Shelf”). The April 2015 Shelf was withdrawn in connection with the TRC/TRP Merger.

May 2016 Shelf

In May 2016, we filed with the SEC a universal shelf registration statement that allows us to issue debt or equity securities (the “May 2016 Shelf”). The May 2016 Shelf will expire in May 2019. See Note 13 – Common Stock and Related Matters.

Debt Repurchases & Extinguishments

In March 2015, we repaid $188.0 million of the term loan and wrote off $3.3 million of the discount and $5.8 million of debt issuance costs. In June 2015, we repaid $82.0 million of the term loan and wrote off $1.4 million of the discount and $2.4 million of debt issuance costs. The write-off of the discount and debt issuance costs are reflected as loss from financing activities in our Consolidated Statements of Operations for the year ended December 31, 2015.

In March 2017, we repaid the entirety of the TRC Senior secured term loan in the amount of $160.0 million. The repayment resulted in write offs of $2.2 million of discount and $3.7 million of debt issuance costs, which are reflected as Loss from financing activities in our Consolidated Statements of Operations for the year ended December 31, 2017.

In June 2017, the Partnership redeemed its outstanding 6 % Senior Notes due August 2022 (“6 % Senior Notes”), totaling $278.7 million in aggregate principal amount, at a price of 103.188% of the principal amount plus accrued interest through the redemption date. The redemption resulted in a $10.7 million loss, which is reflected as 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, the Partnership redeemed its outstanding 5% Senior Notes due 2018 at par value plus accrued interest through the redemption date. The redemption resulted in a non-cash Loss from financing activities to write-off $0.2 million of unamortized debt issuance costs during the year ended December 31, 2017.

During the year ended December 31, 2015, the Partnership repurchased on the open market a portion of its outstanding Senior Notes as follows:

Debt Repurchased	Book Value	Payment	Gain/(Loss)	Write-off of Debt Issuance Costs	Net Gain/(Loss)
5¼% Senior Notes	$ 16.3	$ (13.0)	$ 3.3	$ (0.1)	$ 3.2
4¼% Senior Notes	1.5	(1.2)	0.3	—	0.3
6 % Senior Notes	0.1	(0.1)	—	—	—
	$ 17.9	$ (14.3)	$ 3.6	$ (0.1)	$ 3.5

During the year ended December 31, 2016, the Partnership repurchased on the open market a portion of its outstanding Senior Notes as follows:

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

During the year ended December 31, 2017, the Partnership did not repurchase any of its outstanding Senior Notes on the open market.

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

Senior Notes Tender Offers

Concurrently with the October 2016 Offering, the Partnership commenced tender offers (the "Tender Offers") to purchase for cash, subject to certain conditions, up to specified aggregate maximum purchase amounts of our 5% Senior Notes, 6 % Senior Notes due October 2020 (the "6 % Senior Notes") and 6 % Senior Notes due February 2021 (the "6 % Senior Notes" and together with the 5% Senior Notes and 6 % Senior Notes, the "Tender Notes"). The total consideration for each series of Tender Notes included a premium for each $1,000 principal amount of notes that was tendered as of the early tender date of October 5, 2016. The Tender Offers were fully subscribed and the Partnership accepted for purchase all Tender Notes that were validly tendered as of the early tender date.

The results of the Tender Offers, which closed in October 2016, were:

Debt Tendered	Outstanding Note Balance Prior to Tender Offers	Amount Tendered	Premium Paid	Accrued Interest Paid	Total Tender Offer Payments	Note Balance After Tender Offers
5% Senior Notes	$ 733.6	$ 483.1	$ 16.9	$ 5.4	$ 505.4	$ 250.5
6 % Senior Notes	309.9	281.7	10.5	0.3	292.5	28.2
6 % Senior Notes	478.6	373.5	14.4	4.6	392.5	105.1
Total	$ 1,522.1	$ 1,138.3	$ 41.8	$ 10.3	$ 1,190.4	$ 383.8

As a result of the Tender Offers, we recorded during the fourth quarter of 2016 a loss due to debt extinguishment of approximately $59.2 million comprised of the $41.8 million premium paid, the write-off of $5.8 million of debt issuance costs, $15.1 million of debt discounts less $3.5 million of debt premiums.

Note Redemptions

Subsequent to the closing of the Tender Offers in October 2016, the Partnership issued notices of full redemption (the "Note Redemptions") to the trustees and noteholders of the 6 % Notes and the 6 % Notes for the note balances remaining after the Tender Offers. In addition, the Partnership issued notice of full redemption to the trustees of the 6 % Senior Notes of Targa Pipeline Partners LP due October 2020 (the "2020 TPL Notes"). The redemption price for the 6 % Notes and the 2020 TPL Notes was 103.313% of the principal amount, while the redemption price for the 6 % Notes was 103.438% of the principal amount. The aggregate principal amount outstanding of all three series of notes totaling $146.2 million was redeemed on November 15, 2016 for a total redemption payment of $151.1 million, excluding accrued interest. As a result of the Note Redemptions, we recorded during the fourth quarter of 2016 a loss due to debt extinguishment of approximately $9.7 million comprised of the $4.9 million premium paid, the write-off of $1.1 million of debt issuance costs, $4.2 million of debt discounts less $0.5 million of debt premiums.

TPL Senior Notes Tender Offers

In January 2015, the Partnership commenced cash tender offers for any and all of the outstanding fixed rate senior secured notes to be acquired in the APL merger (the "TPL Notes Tender Offers"), which totaled $1.55 billion.

The results of the TPL Notes Tender Offers were:

Debt Tendered	Outstanding Note Balance Prior to Tender Offers	Amount Tendered	Premium Paid	Accrued Interest Paid	Total Tender Offer Payments	% Tendered	Note Balance After Tender Offers
6 % Senior Notes	$ 500.0	$ 140.1	$ 2.1	$ 3.7	$ 145.9	28.02 %	$ 359.9
4¾% Senior Notes	400.0	393.5	5.9	5.3	404.7	98.38 %	6.5
5 % Senior Notes	650.0	601.9	8.7	2.6	613.2	92.60 %	48.1
Total	$ 1,550.0	$ 1,135.5	$ 16.7	$ 11.6	$ 1,163.8		$ 414.5

In connection with the TPL Notes Tender Offers, on February 27, 2015, the supplemental indentures governing the 4¾% Senior Notes due 2021 (the “2021 TPL Notes”) and the 5⅞% Senior Notes due 2023 (the “2023 TPL Notes”) of TPL and Targa Pipeline Finance Corporation (formerly known as Atlas Pipeline Finance Corporation) (together, the “APL Issuers”), became operative. These supplemental indentures eliminated substantially all of the restrictive covenants and certain events of default applicable to the 2021 TPL Notes and the 2023 TPL Notes that were not accepted for payment.

Not having achieved the minimum tender condition on the 2020 TPL Notes, the Partnership made a change of control offer, referred to as the Change of Control Offer, for any and all of the 2020 TPL Notes in advance of, and conditioned upon, the consummation of the APL merger. In March 2015, holders representing $4.8 million of the outstanding 2020 TPL Notes tendered their notes requiring a payment of $5.0 million, which included the change of control premium and accrued interest.

Payments made under the TPL Notes Tender Offers and Change of Control Offer totaling $1,168.8 million are presented as financing activities for the Partnership in our Consolidated Statements of Cash Flows.

Exchange Offer and Consent Solicitation

On April 13, 2015, the Partnership Issuers commenced an offer to exchange (the “Exchange Offer”) any and all of the outstanding 2020 TPL Notes, for an equal amount of new unsecured 6⅝% Senior Notes due 2020 issued by the Partnership Issuers (the “6⅝% Notes” or the “TRP 6⅝% Notes”). On April 27, 2015, the Partnership had received tenders and consents from holders of approximately 96.3% of the total outstanding 2020 TPL Notes. As a result, the minimum tender condition to the Exchange Offer and related consent solicitation was satisfied, and the APL Issuers entered into a supplemental indenture which eliminated substantially all of the restrictive covenants and certain events of default applicable to the 2020 TPL Notes.

In May 2015, upon the closing of the Exchange Offer, the Partnership Issuers issued $342.1 million aggregate principal amount of the TRP 6⅝% Notes to holders of the 2020 TPL Notes which were validly tendered for exchange. The related $5.6 million premium, resulting from acquisition date fair value accounting, will be amortized as an adjustment to interest expense over the remaining term of the TRP 6⅝% Notes. The Partnership recognized $0.7 million of costs associated with the Exchange Offer, included as a loss from financing activities in our Consolidated Statements of Operations.

Debt Repurchases and Extinguishments Summary

The following table summarizes the debt repurchases and extinguishments that are included in our Consolidated Statements of Operations:

	2017	2016	2015
Premium over face value paid upon redemption:			
Partnership 5% Senior Notes	$—	$16.9	$—
Partnership 6 % Senior Notes	—	11.5	—
Partnership 6 % Senior Notes	—	18.0	—
Partnership 6 % TPL Notes	—	0.4	—
Partnership 6 % Senior Notes	8.9	—	—

Recognition of unamortized discount:			
TRC Term Loan, variable rate	—	—	4.7
TRC Senior secured term loan	2.2	—	—
Partnership 6 % Senior Notes	—	19.5	—
Recognition of unamortized premium:			
Partnership 6 % Senior Notes	—	(4.3)	—
Partnership 6 % TPL Notes	—	(0.2)	—
Loss (gain) on repurchase of debt:			
Partnership 5% Senior Notes	—	1.8	—
Partnership 4 % Senior Notes	—	(6.4)	—
Partnership 6 % Senior Notes	—	(2.8)	—
Partnership 6 % Senior Notes	—	(0.8)	—
Partnership 6 % Senior Notes	—	(2.6)	—
Partnership 5¼% Senior Notes	—	(4.0)	(3.3)
Partnership 4¼% Senior Notes	—	(7.7)	(0.3)
Partnership 6¾% Senior Notes	—	(2.4)	—
Loss from financing with Exchange Offer:			
Partnership 6 % Senior Notes	—	—	0.7

Write-off of debt issuance costs:			
TRP Revolver	—	0.9	—
TRC Term Loan, variable rate	—	—	8.2
TRC Senior secured term loan	3.7	—	—
Partnership 5% Senior Notes	0.2	4.2	—
Partnership 4 % Senior Notes	—	0.4	—
Partnership 6 % Senior Notes	—	4.9	—
Partnership 6 % Senior Notes	1.8	0.2	—
Partnership 5¼% Senior Notes	—	0.2	0.1
Partnership 4¼% Senior Notes	—	0.3	—
Partnership 6¾% Senior Notes	—	0.2	—
Loss from financing activities	$16.8	$48.2	$10.1

Note 11 — Other Long-term Liabilities

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

	December 31, 2017	December 31, 2016
Asset retirement obligations	$ 50.8	$ 64.6
Mandatorily redeemable preferred interests	76.2	68.5
Deferred revenue	136.2	69.8
Permian Acquisition contingent consideration, noncurrent portion	310.2	—
Other liabilities	24.5	12.2
Total long-term liabilities	$ 597.9	$ 215.1

Asset Retirement Obligations

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

	2017	2016
Beginning of period	$64.6	$70.4
Additions (1)	0.8	—
Reduction due to sale of VGS	(21.6)	—
Change in cash flow estimate	3.1	(9.1)
Accretion expense	3.9	4.6
Retirement of ARO	—	(1.3)
End of period	$50.8	$64.6

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

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, 2017, 2016 and 2015, interest earned on the notes receivable of $10.3 million, $10.5 million, and $8.9 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, 2017. The aggregate fair values of the notes receivable and the estimated redemption values of our partner's interest in the joint ventures as of the reporting date are presented on the Consolidated Balance Sheets on a net basis.

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

	2017	2016
Beginning of period	$68.5	$82.9
Income attributable to mandatorily redeemable preferred interests	4.4	0.8
Change in estimated redemption value included in interest expense	3.3	(15.2)
End of period	$76.2	$68.5

Subsequent Event

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. Such amendments will impact the estimated redemption value of the mandatorily redeemable preferred interest on a go forward basis. Specifically, the amendments may impact the market value of the joint venture's assets allocable to the partners.

Deferred Revenue

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

Deferred revenue includes consideration received related to the construction and operation of a crude oil and condensate splitter. On December 27, 2015, Targa Terminals LLC and Noble Americas Corp., a subsidiary of Noble Group Ltd., entered into a long-term, fee-based agreement ("Splitter Agreement") under which we will build and operate a crude oil and condensate splitter at our Channelview Terminal on the Houston Ship Channel ("Channelview Splitter") and provide approximately 730,000 Bbl of storage capacity. The Channelview Splitter will have the capability to split approximately 35,000 Bbl/d of crude oil and condensate into its various components, including naphtha, kerosene, gas oil, jet fuel, and liquefied petroleum gas and will provide segregated storage for the crude, condensate and components. The Channelview Splitter project is expected to be completed in the second quarter of 2018, and has an estimated total cost of approximately $140 million. The first annual advance payment due under the Splitter Agreement was received in October 2016 and has been recorded as deferred revenue, as the Splitter Agreement requires future performance by Targa. The Splitter Agreement provides that subsequent annual payments of $43.0 million (subject to an annual inflation factor) are to be paid to Targa through 2022. In October 2017, we received $43.0 million representing the second annual payment under the Splitter Agreement, which has been recorded as deferred revenue. The deferred revenue receipts will be recognized over the contractual period that future performance will be provided, currently anticipated to commence with start-up in 2018 and continuing through 2025.In January 2018, Vitol US Holding Co. acquired Noble Americas Corp.

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. Because the gas contract amendment will require future performance by Targa, we have recorded the consideration received as deferred revenue. 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 will be recognized over the periods that future performance will be provided, which extend through 2023.

For the years ended December 31, 2017, 2016 and 2015, we recognized approximately $3.1 million, $3.1 million and $2.7 million of revenue for these transactions.

The following table shows the components of deferred revenue:

	December 31, 2017	December 31, 2016
Splitter agreement	$ 86.0	$ 43.0
Gas contract amendment	44.7	19.7
Other deferred revenue	5.5	7.1
Total deferred revenue	$ 136.2	$ 69.8

The following table shows the changes in deferred revenue:

	2017	2016
Beginning of period	$69.8	$27.7
Additions	69.5	45.2
Revenue recognized	(3.1)	(3.1)
End of period	$136.2	$69.8

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 potential earn-out payments will be based upon a multiple of gross margin realized during the first two annual periods after the acquisition date from contracts that existed on March 1, 2017. The first potential earn-out payment would occur in May 2018 and the second potential earn-out payment would occur in May 2019. The preliminary acquisition date fair value of the contingent consideration of $461.6 million was recorded within Other long-term liabilities on our Consolidated Balance Sheets as of March 31, 2017. Subsequent changes in the fair value of the contingent consideration that were not accounted for as revisions (measurement period adjustments) to the acquisition date fair value have been included in Other income (expense).

During the three months ended June 30, 2017, we recognized certain adjustments that were accounted for as revisions to the acquisition date fair value and decreased the acquisition date fair value of the contingent consideration by $45.3 million to $416.3 million. During the three months ended September 30, 2017, we finalized the purchase price allocation with no additional revisions to the acquisition date fair value. See Note 4 – Acquisitions and Divestments for additional discussion.

For the period from the acquisition date to December 31, 2017, the fair value of this liability decreased by $99.3 million, bringing the total Permian Acquisition contingent consideration to $317.0 million at December 31, 2017. The decrease in fair value of the contingent consideration was primarily related to reductions in actual and forecasted volumes and gross margin as a result of changes in producers' drilling activity in the region since the acquisition date. Such changes in estimated fair value of the contingent consideration are attributable to events and circumstances that occurred after the acquisition date, and as such have been recognized in Other income (expense).

As of December 31, 2017, the fair value of the first potential earn-out payment of $6.8 million has been recorded as a component of Accounts payable and accrued liabilities, which are current liabilities on our Consolidated Balance Sheets. As of December 31, 2017, the fair value of the second potential earn-out payment of $310.2 million has been recorded within Other long-term liabilities on our Consolidated Balance Sheets. See Note 17 – Fair Value Measurements for additional discussion of the fair value methodology.

The following table shows the changes in contingent consideration:

Balance at March 1, 2017 (acquisition date)	$461.6
Measurement period adjustment of acquisition date value	(45.3)
Decrease in fair value due to factors occurring after acquisition date	(99.3)
Balance at December 31, 2017	317.0
Less: Current portion	(6.8)
Long-term balance at December 31, 2017	$310.2

Note 12 – Preferred Stock

Preferred Stock and Detachable Warrants

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

The Series A Preferred has a liquidation value of $1,000 per share and bears a cumulative 9.5% fixed dividend payable quarterly 45 days after the end of each fiscal quarter. The Series A Preferred ranks senior to the common outstanding stock with respect to the payment of dividends and distributions in liquidation. We had the option to elect to pay dividends for any quarter with a paid-in-kind election ("PIK") through December 31, 2017. Under the PIK election, unpaid dividends would have been added to the liquidation preference and a commensurate amount of Series A and Series B Warrants would have been issued. We did not make an election to PIK through December 31, 2017. The Series A Preferred has no mandatory redemption date, but is redeemable at our election in year six for a 10% premium to the liquidation preference and for a 5% premium to the liquidation preference thereafter. If the Series A Preferred is not redeemed by the end of year twelve, the investors have the right to convert the Series A Preferred into TRC common stock at an exercise price of $20.77, which represented a 10% premium over the ten-day volume weighted average price ("VWAP") prior to the February 18, 2016 signing date ($18.88) of the Purchase Agreement underlying the first tranche. If the investors do not elect to convert their Series A Preferred into TRC common stock, Targa has a right after year twelve to force conversion, but only if the VWAP for the ten preceding trading days is greater than 120% of the conversion price. A change of control provision could result in forced redemption, at the option of the investor, if the Series A Preferred could not otherwise remain outstanding or be replaced with a "substantially equivalent security." The change of control premium to the liquidation preference on the redemption is initially 25% in year one, 20% in year two, 15% in year three, 10% in years four through six and 5% thereafter.

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

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

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

The Series A Preferred is a hybrid security and is viewed as a debt host for the purpose of evaluating embedded derivatives. Bifurcation of the Company's redemption provision is not required because the redemption provision is clearly and closely related to the preferred debt host. Further, both our and the investors' conversion options qualify for a derivatives scope exception under ASC 815 – Derivatives and Hedging ("ASC 815") applicable to embedded features that are indexed to an entity's equity, and that would be classified as equity if freestanding.

The Series A Preferred does not qualify as a liability instrument under ASC 480 – Distinguishing Liabilities from Equity, because it is not mandatorily redeemable. However, as SEC Regulation S-X, Rule 5-02-27 does not permit a probability assessment for a change of control provision our Series A Preferred must be presented as mezzanine equity between liabilities and shareholders' equity on our Consolidated Balance Sheets because a change of control event, although not considered probable, could force the Company to redeem the Series A Preferred. At each balance sheet date, we must re-evaluate whether the Series A Preferred continues to qualify for treatment as an equity instrument. Under the terms of the Registration Rights Agreement covering common stock issuable upon conversion of the Series A Preferred (the "Preferred Registration Rights Agreement"), we will cause a registration statement with respect to the common shares underlying the Series A Preferred to be declared effective within 12 years of the March 16, 2016 issue date (the "Effective Date"), and pay liquidated damages in the event we fail to do so. A maximum of 46,466,057 common shares would be issued upon conversion of the Series A Preferred.

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

Net cash proceeds were allocated on a relative fair value basis to the Series A Preferred, Series A Warrants and Series B Warrants. The $178.1 million discount on the Series A Preferred created by the relative fair value allocation of proceeds, which is not subject to periodic accretion, would be reported as a deemed dividend in the event a redemption occurs. As described below, $614.4 million of the $787.1 million allocated to the Series A Preferred was allocated to additional paid-in capital to give effect to the intrinsic value of a beneficial conversion feature ("BCF").

	Allocation of Proceeds			
		Additional Paid-in Capital		
	Series A Preferred	Series A Warrants	Series B Warrants	Beneficial Conversion Feature

Gross proceeds	$994.1				
Transaction fees	(24.8)				
Net Proceeds- Initial Relative Fair Value Allocation	$969.3	$787.1	$135.7	$ 46.5	$ —
Allocation to BCF		(614.4)	—	—	614.4
Per balance sheet upon issuance		$172.7	$135.7	$ 46.5	$ 614.4

Beneficial Conversion Feature

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

We have the right to redeem the Series A Preferred beginning after year five. As such, we can effectively mitigate or limit the Series A Preferred Holders’ ability to benefit from their conversion right after year twelve by paying either a $96.5 million (10%) redemption premium in year six or a $48.3 million (5%) redemption premium in years seven through twelve. In either case, the redemption premium would be significantly less than the $614.4 million BCF required to be recognized under GAAP. Upon exercise of our redemption rights, any previously recognized accretion of deemed dividends would be reversed in the period of redemption and reflected as income attributable to common shareholders in our Consolidated Statements of Operations and related per share amounts.

Preferred Stock Dividends

As of December 31, 2017, we have accrued cumulative preferred dividends of $22.9 million, which were paid on February 14, 2018. During the year ended December 31, 2017, we paid $91.7 million of dividends to preferred shareholders, and recorded deemed dividends of $25.7 million attributable to accretion of the preferred discount resulting from the BCF accounting described above. Such accretion is included in the book value of the Series A Preferred Stock.

Note 13 — Common Stock and Related Matters

Public Offerings of Common Stock

On February 27, 2015, we issued 10,126,532 shares of our common stock valued at approximately $1.0 billion in exchange for ATLS common units as part of the Atlas mergers (based on the $99.58 closing market price of our common shares on the NYSE as of February 27, 2015). In addition, we awarded 81,740 RSUs in connection with the Atlas mergers.

In March 2015, we sold, in a public offering, 3,250,000 shares of our common stock under a registration statement on Form S-3 at a price of $91.00 per share of common stock, providing net proceeds of $292.8 million to us. Pursuant to the exercise of the underwriters' overallotment option, we also sold an additional 487,500 shares of our common stock, providing additional net proceeds of $43.9 million. The proceeds from this offering were used to repay a portion of the outstanding borrowings under our term loan and to make a capital contribution of $52.4 million to the Partnership to maintain our 2% general partnership interest in the Partnership and for general corporate purposes.

In May 2016, we entered into an equity distribution agreement under the May 2016 Shelf (the "May 2016 EDA"), pursuant to which we may sell, at our option, up to an aggregate of $500.0 million of our common stock. The common stock available for sale under the May 2016 EDA was registered pursuant to a registration statement on Form S-3 filed on May 23, 2016. During 2016, we issued 11,074,266 shares of common stock under the May 2016 EDA, receiving net proceeds of $494.0 million. In December 2016, we terminated the May 2016 EDA with a remaining amount of $2.2 million.

In December 2016, we entered into another equity distribution agreement under the May 2016 Shelf (the "December 2016 EDA"), pursuant to which we may sell, at our option, up to an aggregate of $750.0 million of our common stock. In connection with the December 2016 EDA we terminated the May 2016 EDA. During 2016, we issued 1,487,100 shares of common stock under the December 2016 EDA, receiving net proceeds of $78.7 million.

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

On May 9, 2017, we entered into an equity distribution agreement under the May 2016 Shelf (the "May 2017 EDA"), pursuant to which we may sell through our sales agents, at our option, up to an aggregated amount of $750.0 million of our common stock. For the year ended December 31, 2017, no shares of common stock have been issued under the May 2017 EDA.

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

For the year ended December 31, 2017, we issued 6,433,561 shares of common stock under our December 2016 EDA, receiving net proceeds of $343.1 million. As of December 31, 2017, we have $324.1 million remaining under the December 2016 EDA.

TRC/TRP Merger

On February 17, 2016, we completed the TRC/TRP Merger and issued 104,525,775 shares of our common stock in exchange for all of the outstanding common units of the Partnership that we previously did not own. See Note 2 – Basis of Presentation.

Warrants

During 2016, 19,983,843 Warrants were exercised and net settled for 11,336,856 shares of common stock. For the year ended December 31, 2017, no detachable Warrants were exercised. As a result, Series A Warrants exercisable into a maximum of 67,392 shares of common stock and Series B Warrants exercisable into maximum of 32,496 shares of common stock were outstanding as of December 31, 2017.

Subsequent Event

In January 2018, we issued 1,162,963 shares of common stock under our December 2016 EDA, receiving net proceeds of $57.7 million. As of February 9, 2018, we have $266.0 million remaining under the December 2016 EDA.

In February 2018, the remaining 99,888 Warrants were exercised and net settled by us for 58,814 shares of common stock.

Dividends

The following table details the dividends declared and/or paid by us to common shareholders for the years ended December 31, 2017, 2016 and 2015:

Three Months Ended	Date Paid or To Be Paid	Total Common Dividends Declared	Amount of Common Dividends Paid or To Be Paid	Accrued Dividends (1)	Dividends Declared per Share of Common Stock (per share amounts)
2017					
December 31, 2017	February 15, 2018	$ 202.4	$ 199.1	$ 3.3	$ 0.91000
September 30, 2017	November 15, 2017	199.0	196.2	2.8	0.91000
June 30, 2017	August 15, 2017	198.6	196.2	2.4	0.91000
March 31, 2017	May 16, 2017	182.8	180.3	2.5	0.91000
2016					
December 31, 2016	February 15, 2017	$ 178.3	$ 176.5	$ 1.8	$ 0.91000
September 30, 2016	November 15, 2016	166.4	164.6	1.8	0.91000
June 30, 2016	August 15, 2016	153.1	151.6	1.5	0.91000
March 31, 2016	May 16, 2016	147.8	146.1	1.7	0.91000
2015					
December 31, 2015	February 9, 2016	$ 51.7	$ 51.0	$ 0.7	$ 0.91000
September 30, 2015	November 16, 2015	51.3	51.0	0.3	0.91000
June 30, 2015	August 17, 2015	49.2	49.0	0.2	0.87500
March 31, 2015	May 18, 2015	46.6	46.4	0.2	0.83000

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

Note 14 — Partnership Units and Related Matters

Common Units Equity Offerings

As part of the Atlas merger in February 2015, the Partnership issued 58,614,157 common units to former APL unitholders as consideration for the APL merger, of which 3,363,935 common units represented ATLS's common unit ownership in APL and were issued to us. We contributed $52.4 million to the Partnership to maintain our 2% general partner interest.

In May 2015, the Partnership entered the May 2015 EDA under the April 2015 Shelf pursuant to which the Partnership may sell through our sales agents, at its option, up to an aggregate of $1.0 billion of its common units. As of December 31, 2015, the Partnership had issued 7,377,380 common units under its EDAs, receiving net proceeds of $316.1 million. As of December 31, 2015, approximately $4.2 million of capacity and $835.6 million of capacity remained under the May 2014 and May 2015 EDAs. We contributed $6.5 million to the Partnership to maintain our 2% general partner interest.

In connection with the TRC/TRP Merger, the Partnership's April 2015 Shelf was withdrawn.

TRC/TRP Merger

On February 17, 2016, TRC completed the TRC/TRP Merger, indirectly acquiring all of the outstanding common units not already owned by us and our subsidiaries. As a result of the TRC/TRP Merger, we own all of the Partnership's outstanding common units.

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

Pursuant to the TRC/TRP Merger Agreement, TRC caused the TRP common units to be delisted from the NYSE and deregistered under the Exchange Act. As a result of the completion of the TRC/TRP Merger, the TRP common units are no longer publicly traded. The Partnership's 5,000,000 Preferred Units remain outstanding as preferred limited partner interests in the Partnership and continue to trade on the NYSE.

Distributions

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

The following details the distributions declared or paid by the Partnership during 2017, 2016 and 2015:

Three Months Ended	Date Paid Or to Be Paid	Total Distributions	Distributions to Targa Resources Corp.
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
2016			
December 31, 2016	February 10, 2017	$ 198.1	$ 195.3
September 30, 2016	November 11, 2016	194.7	191.9
June 30, 2016	August 11, 2016	181.7	178.9
March 31, 2016	May 12, 2016	157.6	154.8
2015			
December 31, 2015	February 9, 2016	$ 200.4	$ 61.4
September 30, 2015	November 13, 2015	200.4	61.4
June 30, 2015	August 14, 2015	200.4	61.4
March 31, 2015	May 15, 2015	193.9	59.0

Pursuant to the IDR Giveback Amendment in conjunction with the Atlas mergers, IDRs of $9.375 million were reallocated to common unitholders for each of the four quarters of 2015. The IDR Giveback Amendment covered sixteen quarterly distribution declarations following the completion of the Atlas mergers on February 27, 2015. The IDR Giveback resulted in reallocation of IDR payments to common unitholders of $6.25 million for each of the first three quarters of 2016.

On October 19, 2016, the Partnership executed the Third A&R Partnership Agreement, which became effective on December 1, 2016. The Third A&R Partnership Agreement amendments include among other things (i) eliminating the IDRs held by the general partner, and related distribution and allocation provisions, (ii) eliminating the Special GP Interest (as defined in the Third A&R Partnership Agreement) held by the general partner, (iii) providing the ability to declare monthly distributions in addition to quarterly distributions, (iv) modifying certain provisions relating to distributions from available cash, (v) eliminating the Class B Unit provisions and (vi) changes to the Third A&R Partnership Agreement to reflect the passage of time and to remove provisions that are no longer applicable.

As a result of the Third A&R Partnership Agreement, the reallocations of IDRs under the IDR Giveback Amendment ceased in the fourth quarter of 2016.

On December 1, 2016 the Partnership issued to the General Partner (i) 20,380,286 common units and 424,590 General Partner units in exchange for the elimination of the IDRs and (ii) 11,267,485 common units and 234,739 General Partner units in exchange for the elimination of the Special GP Interest in connection with the Third A&R Partnership Agreement.

Contributions

Subsequent to the TRC/TRP Merger, 58,621,036 common units and 1,196,346 general partner units were issued for our contributions of $1,191.0 million. Subsequent to the effective date of the Third A&R Partnership Agreement, no units will be issued for capital contributions but all capital contributions will continue to be allocated 98% to the limited partner and 2% to the general partner. In December 2016, we made a $190.0 million capital contribution to the Partnership which was allocated accordingly. For the year ended December 31, 2017, we made total capital contributions to the Partnership of $1,720.0 million.

Preferred Units

In October 2015, under the April 2013 Shelf, the Partnership completed an offering of 4,400,000 Preferred Units at a price of $25.00 per unit. Pursuant to the exercise of the underwriters' overallotment option, the Partnership sold an additional 600,000 Preferred Units at a price of $25.00 per unit. The Partnership received net proceeds after costs of approximately $121.1 million. The Partnership used the net proceeds from this offering to reduce borrowings under its senior secured credit facility and for general partnership purposes. The Preferred Units are listed on the NYSE under the symbol "NGLS PRA."

Distributions on the Partnership's 5,000,000 Preferred Units are cumulative from the date of original issue in October 2015 and are payable monthly in arrears on the 15th day of each month of each year, when, as and if declared by the board of directors of the Partnership's general partner. Distributions on the Preferred Units will be payable out of amounts legally available therefor from at a rate equal to 9.0% per annum. On and after November 1, 2020, distributions on the Preferred Units will accumulate at an annual floating rate equal to the one-month LIBOR plus a spread of 7.71%.

The Preferred Units, with respect to anticipated monthly distributions, rank:

- senior to the Partnership's 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 the Partnership's existing and future indebtedness (including (i) indebtedness outstanding under the TRP Revolver, (ii) the Partnership's senior notes and (iii) indebtedness outstanding under the Securitization Facility and other liabilities with respect to assets available to satisfy claims against the Partnership; 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, the Partnership 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, the Partnership (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 the Partnership does 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 the Partnership Agreement. If the Partnership exercises (or a third party with our prior written consent exercises) its redemption rights relating to any Preferred Units, the holders of those Preferred Units 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 the Partnership Agreement.

As of December 31, 2017, the Partnership has 5,000,000 Preferred Units outstanding. The Partnership paid $11.3 million, $11.3 million and $1.5 million of distributions to the Preferred Unitholders during the years ended December 31, 2017, 2016 and 2015. The Preferred Units are reported as noncontrolling interests in our financial statements.

In January and February 2018, the board of directors of the general partner of the Partnership declared a cash distribution of $0.1875 per Preferred Unit, resulting in approximately $0.9 million in distributions each month. The distributions declared in January were paid on February 15, 2018 and the distributions declared in February will be paid on March 15, 2018.

Note 15 — Earnings per Common Share

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

	2017	2016	2015
Net income	$104.2	$(159.1)	$(151.4)
Less: Net income attributable to noncontrolling interests	50.2	28.2	(209.7)
Less: Dividends on preferred stock	117.4	90.8	—
Net income attributable to common shareholders for basic earnings per share	$(63.4)	$(278.1)	$58.3
Weighted average shares outstanding - basic	206.9	154.4	53.5
Net income available per common share - basic	$(0.31)	$(1.80)	$1.09
Weighted average shares outstanding	206.9	154.4	53.5
Dilutive effect of common stock equivalents	—	—	0.1
Weighted average shares outstanding - diluted	206.9	154.4	53.6
Net income available per common share - diluted	$(0.31)	$(1.80)	$1.09

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

	2017	2016	2015
Unvested restricted stock awards	1.2	0.6	0.1
Warrants to purchase common stock	0.1	5.8	—
Series A Preferred Stock (1)	46.5	36.9	—

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

Note 16 — Derivative Instruments and Hedging Activities

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

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

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

As part of the Atlas mergers, outstanding TPL derivative contracts with a fair value of $102.1 million as of the acquisition date were novated to us and included in the acquisition date fair value of assets acquired. We received derivative settlements of $7.6 million, $26.6 million, and $67.9 million for the years ended December 31, 2017, 2016 and 2015, related to these novated contracts. The final settlement was received in December 2017. These settlements were reflected as a reduction of the acquisition date fair value of the TPL derivative assets acquired and had no effect on results of operations.

The "off-market" nature of these acquired derivatives can introduce a degree of ineffectiveness for accounting purposes due to an embedded financing element representing the amount that would be paid or received as of the acquisition date to settle the derivative contract. The resulting ineffectiveness can either potentially disqualify the derivative contract in its entirety for hedge accounting or alternatively affect the amount of unrealized gains or losses on qualifying derivatives that can be deferred from inclusion in periodic net income. Additionally, we recorded ineffectiveness losses of $0.2 million, $0.3 million, and $0.9 million for the years ended December 31, 2017, 2016 and 2015, related to otherwise qualifying TPL derivatives, which are primarily natural gas swaps.

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

At December 31, 2017, the notional volumes of our commodity derivative contracts were:

Commodity	Instrument	Unit	2018	2019	2020
Natural Gas	Swaps	MMBtu/d	166,470	131,506	-
Natural Gas	Basis Swaps	MMBtu/d	99,521	12,500	10,417
Natural Gas	Futures	MMBtu/d	466	-	-
Natural Gas	Options	MMBtu/d	9,486	-	-
NGL	Swaps	Bbl/d	19,298	9,889	427
NGL	Futures	Bbl/d	14,661	329	-
NGL	Options	Bbl/d	2,986	410	-
Condensate	Swaps	Bbl/d	3,790	1,753	-
Condensate	Options	Bbl/d	691	590	-

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

		Fair Value as of December 31, 2017		Fair Value as of December 31, 2016	
	Balance Sheet Location	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Derivatives designated as hedging instruments					
Commodity contracts	Current	$ 37.9	$ 78.6	$ 16.7	$ 48.6
	Long-term	23.2	18.7	5.1	26.1
Total derivatives designated as hedging instruments		$ 61.1	$ 97.3	$ 21.8	$ 74.7
Derivatives not designated as hedging instruments					
Commodity contracts	Current	$ -	$ 1.1	$ 0.1	$ 0.5
	Long-term	-	0.9	-	-
Total derivatives not designated as hedging instruments		$ -	$ 2.0	$ 0.1	$ 0.5
Total current position		$ 37.9	$ 79.7	$ 16.8	$ 49.1

Total long-term position	23.2	19.6	5.1	26.1
Total derivatives	$ 61.1	$ 99.3	$ 21.9	$ 75.2

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

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

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

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

The fair value of our derivative instruments, depending on the type of instrument, was determined by the use of present value methods or standard option valuation models with assumptions about commodity prices based on those observed in underlying markets. The estimated fair value of our derivative instruments was a net liability of $38.2 million as of December 31, 2017. The estimated fair value is net of an adjustment for credit risk based on the default probabilities as indicated by market quotes for the counterparties' credit default swap rates. The credit risk adjustment was immaterial for all periods presented. Our futures contracts that are cleared through an exchange are margined daily and do not require any credit adjustment.

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

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivatives (Effective Portion) 2017	2016	2015
Commodity contracts	$ (28.8)	$ (103.6)	$ 112.7

Location of Gain (Loss)	Gain (Loss) Reclassified from OCI into Income (Effective Portion) 2017	2016	2015
Revenues	(44.6)	45.0	86.3

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.

Derivatives Not Designated as Hedging Instruments	Location of Gain Recognized in Income on Derivatives	Gain (Loss) Recognized in Income on Derivatives 2017	2016	2015
Commodity contracts	Revenue	$(5.1)	$0.9	$(5.7)

Based on valuations as of December 31, 2017, we expect to reclassify commodity hedge related deferred losses of $35.2 million included in accumulated other comprehensive income into earnings before income taxes through the end of 2020, with $39.9 million of losses to be reclassified over the next twelve months.

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

Note 17 — Fair Value Measurements

Under GAAP, our Consolidated Balance Sheets reflect a mixture of measurement methods for financial assets and liabilities (“financial instruments”). Derivative financial instruments and contingent consideration related to business acquisitions are reported at fair value 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, 2017, a net liability position of $38.2 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 $127.5 million, ignoring an adjustment for counterparty credit risk. If forward pricing on natural gas, NGLs and crude oil were to decrease by 10%, the result would be a fair value reflecting a net asset of $51.1 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 TRC Revolver, TRP Revolver, and the Partnership’s accounts receivable securitization facility are based on carrying value, which approximates fair value as their interest rates are based on prevailing market rates; and
- Our term loan (prior to its repayment) and the Partnership’s senior unsecured notes are based on quoted market prices derived from trades of the debt.

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

Fair Value Hierarchy

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

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

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

	December 31, 2017				
	Carrying	Fair Value			
	Value	Total	Level 1	Level 2	Level 3
Financial Instruments Recorded on Our Consolidated Balance Sheets at Fair Value:					
Assets from commodity derivative contracts (1)	$60.3	$60.3	$ —	$58.8	$1.5
Liabilities from commodity derivative contracts (1)	98.5	98.5	—	93.3	5.2
Permian Acquisition contingent consideration (2)	317.0	317.0	—	—	317.0
TPL contingent consideration (3)	2.4	2.4	—	—	2.4
Financial Instruments Recorded on Our Consolidated Balance Sheets at Carrying Value:					
Cash and cash equivalents	137.2	137.2	—	—	—
TRC Revolver	435.0	435.0	—	435.0	—
TRC term loan	—	—	—	—	—
TRP Revolver	20.0	20.0	—	20.0	—
Partnership's Senior unsecured notes	4,278.0	4,362.4	—	4,362.4	—
Partnership's accounts receivable securitization facility	350.0	350.0	—	350.0	—

	December 31, 2016				
	Carrying	Fair Value			
	Value	Total	Level 1	Level 2	Level 3
Financial Instruments Recorded on Our Consolidated Balance Sheets at Fair Value:					
Assets from commodity derivative contracts (1)	$21.0	$21.0	$ —	$19.6	$ 1.4
Liabilities from commodity derivative contracts (1)	74.2	74.2	—	69.3	4.9
Permian Acquisition contingent consideration (2)	—	—	—	—	—
TPL contingent consideration (3)	2.6	2.6	—	—	2.6
Financial Instruments Recorded on Our Consolidated Balance Sheets at Carrying Value:					
Cash and cash equivalents	73.5	73.5	—	—	—
TRC Revolver	275.0	275.0	—	275.0	—
TRC term loan	157.8	158.4	—	158.4	—
TRP Revolver	150.0	150.0	—	150.0	—
Partnership's Senior unsecured notes	4,057.3	4,101.6	—	4,101.6	—
Partnership's accounts receivable securitization facility	275.0	275.0	—	275.0	—

(1) The fair value of derivative contracts in this table is presented on a different basis than the Consolidated Balance Sheets presentation as disclosed in Note 16 – Derivative Instruments and Hedging Activities. The above fair values reflect the total value of each derivative contract taken as a whole, whereas the Consolidated Balance Sheets presentation is based on the individual maturity dates of estimated future settlements. As such, an individual contract could have both an asset and liability position when segregated into its current and long-term portions for Consolidated Balance Sheets classification purposes.
(2) We have a contingent consideration liability related to the Permian Acquisition, which is carried at fair value. See Note 4 – Acquisitions and Divestitures.
(3) We have a contingent consideration liability for TPL's previous acquisition of a gas gathering system and related assets, which is carried at fair value.

Additional Information Regarding Level 3 Fair Value Measurements Included on Our Consolidated Balance Sheets

We reported certain of our swaps and option contracts at fair value using Level 3 inputs due to such derivatives not having observable implied volatilities or market prices for substantially the full term of the derivative asset or liability. For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations whose contract length extends into unobservable periods.

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

As of December 31, 2017, we had 14 commodity swap and option contracts categorized as Level 3. The significant unobservable inputs used in the fair value measurements of our Level 3 derivatives are (i) the forward natural gas liquids pricing curves, for which a significant portion of the derivative's term is beyond available forward pricing and (ii) implied volatilities, which are unobservable as a result of inactive natural gas liquids options trading. The change in the fair value of Level 3 derivatives associated with a 10% change in the forward basis curve where prices are not observable is immaterial.

The fair value of the Permian Acquisition contingent consideration was determined using a Monte Carlo simulation model. Significant inputs used in the fair value measurement include expected gross margin (calculated in accordance with the terms of the purchase and sale agreements), term of the earn-out period, risk adjusted discount rate and volatility associated with the underlying assets. A significant decrease in expected gross margin during the earn-out period, or significant increase in the discount rate or volatility would result in a lower fair value estimate. The fair value of the TPL contingent consideration was determined using a probability-based model measuring the likelihood of meeting certain volumetric measures. The inputs for both models are not observable; therefore, the entire valuations of the contingent considerations are categorized in Level 3. Changes in the fair value of these liabilities are included in Other income (expense) in our Consolidated Statements of Operations.

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

	Commodity	Contingent

	Derivative Contracts Asset/(Liability)	Liability
Balance, December 31, 2016	$ (3.6)	$ (2.6)
Change in fair value of TPL contingent consideration	-	0.2
Fair value of Permian Acquisition contingent consideration (1)	-	(317.0)
New Level 3 derivative instruments	(0.2)	-
Transfers out of Level 3 (2)	4.2	-
Settlements included in Revenue	-	-
Unrealized gain/(loss) included in OCI	(4.2)	-
Balance, December 31, 2017	$ (3.8)	$ (319.4)

(1) Represents the December 31, 2017 balance of the contingent consideration that arose as part of the Permian Acquisition in the first quarter of 2017. See Note 4 – Acquisitions and Divestitures for discussion of the initial fair value.

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

Note 18 — Related Party Transactions

Transactions with Unconsolidated Affiliates

For the years ended December 31, 2017, 2016 and 2015, transactions with GCF included in revenues were $0.3 million, $0.4 million and $0.5 million. For the same periods, transactions with GCF included in costs and expenses were $4.4 million, $3.2 million and $5.8 million. We are subject to paying a deficiency fee in instances where we do not deliver our minimum volume requirements as outlined in the partnership and fractionation agreements with GCF.

We engage in the purchase and sale of residue gas and condensate with the T2 Joint Ventures. Revenue attributable to sales to T2 Eagle Ford and T2 Cogen were $2.0 million and $0.1 million for the year ended December 31, 2017, $4.6 million and $0.6 million for the year ended December 31, 2016, and $4.4 million and $1.4 million for the year ended December 31, 2015. Cost of sales attributable to T2 Eagle Ford were $1.1 million, $2.6 million and $4.0 million for the years ended December 31, 2017, 2016 and 2015. Capacity lease fees paid to T2 Eagle Ford and T2 LaSalle and included in operating expenses were $3.1 million and $0.7 million for the year ended December 31, 2017, $3.2 million and $0.8 million for the year ended December 31, 2016, and $3.0 million and $1.3 million for the year ended December 31, 2015. These fees are billed to us based on our portion of the cost to operate each respective joint venture. As a result of this activity, we had a payable balance with T2 Eagle Ford of $0.3 million at December 31, 2017 and a receivable balance of $0.2 million at December 31, 2016.

Relationship with Targa Resources Partners LP

We provide general and administrative and other services to the Partnership, associated with the Partnership's existing assets and assets acquired from third parties. The Partnership Agreement between the Partnership and us, as general partner of the Partnership, governs the reimbursement of costs incurred on the behalf of the Partnership.

The employees supporting the Partnership's operations are employees of us. The Partnership reimburses us for the payment of certain operating expenses, including compensation and benefits of operating personnel assigned to the Partnership's assets, and for the provision of various general and administrative services for the benefit of the Partnership. We perform centralized corporate functions for the Partnership, such as legal, accounting, treasury, insurance, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes, engineering and marketing. Since October 1, 2010, after the final conveyance of assets by us to the Partnership, substantially all of our general and administrative costs have been and will continue to be allocated to the Partnership, other than (1) costs attributable to our status as a separate reporting company and (2) our costs of providing management and support services to certain unaffiliated spun-off entities.

Relationship with Sajet Resources LLC

Former holders of our pre-IPO common equity, including certain of our executive managers and directors, own a controlling interest in Sajet Resources LLC ("Sajet"), which was spun-off in December 2010 prior to the IPO. Sajet owns certain technology rights, real property and ownership interests in Allied CNG Ventures LLC. We provide general and administrative services to Sajet and are reimbursed for these amounts at our actual cost. Services provided to Sajet during the years ended December 31, 2017, 2016 and 2015 totaled $0.3 million, $0.5 million, and $1.1 million, respectively.

Relationship with Tesla Resources LLC

In September 2012, Tesla Resources LLC ("Tesla") was spun-off from Sajet. Tesla has ownership interests in Floridian Natural Gas Storage Company LLC ("Floridian"). We provide general and administrative services to Tesla and Floridian and are reimbursed for these amounts at our actual cost. Services provided to Tesla and Floridian during the years ended December 31, 2017, 2016 and 2015 totaled $0.1 million, $0.1 million, and $0.2 million, respectively.

Note 19 — Commitments (Leases)

Future lease obligations are presented below in aggregate and for each of the next five fiscal years:

	In Aggregate	2018	2019	2020	2021	2022
Operating leases (1)	$ 42.5	$12.6	$7.5	$7.9	$7.3	$7.2
Land site lease and rights of way (2)	14.6	3.2	3.0	2.8	2.8	2.8
	$ 57.1	$15.8	$10.5	$10.7	$10.1	$10.0

(1) Includes minimum payments on lease obligations for office space, railcars and tractors.

(2) 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 lease obligations, including short-term leases of compressors and equipment, were:

	2017	2016	2015
Operating leases (1)	$49.6	$48.9	$46.0
Land site lease and rights of way	5.2	4.4	4.2
	$54.8	$53.3	$50.2

(1) Includes short-term leases for items such as compressors and equipment.

Note 20 – Contingencies

Legal Proceedings

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

Note 21 – 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, 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 natural gas and/or NGLs or equity volumes 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 and future commodity purchases and sales through 2020. 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 typically 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.

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 all of 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 $61.1 million as of December 31, 2017. The range of losses attributable to our individual counterparties would be between $0.6 million and $22.0 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 $0.1 million as of December 31, 2017 and $0.9 million as of December 31, 2016.

Significant Commercial Relationship

During the years ended December 31, 2017, 2016 and 2015, we did not have any commercial relationships that exceeded 10% of consolidated revenues.

Interest Rate Risk

We are exposed to changes in interest rates, primarily as a result of variable rate borrowings under the TRC Revolver, the TRP Revolver, and the Securitization Facility.

Casualty or Other Risks

We maintain coverage in various insurance programs, which provides us with property damage, business interruption and other coverages which are customary for the nature and scope of our operations. Management believes that we have 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, we 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 22 – Other Operating (Income) Expense

Other Operating (Income) Expense is comprised of the following:

	2017	2016	2015
(Gain) loss on sale or disposal of assets (1)	$15.9	$6.1	$(8.0)
Casualty (gain) loss	-	-	(0.2)
Miscellaneous business tax	0.8	0.5	0.5
Other	0.7	-	0.6
	$17.4	$6.6	$(7.1)

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

Note 23 – Income Taxes

Components of the federal and state income tax provisions for the periods indicated are as follows:

	2017	2016	2015
Current expense (benefit)	$(4.4)	$(62.8)	$15.0
Deferred expense (benefit)	(392.7)	(37.8)	24.6
Total income tax expense (benefit)	$(397.1)	$(100.6)	$39.6

Our deferred income tax assets and liabilities at December 31, 2017 and 2016 consist of differences related to the timing of recognition of certain types of costs as follows:

	2017	2016
Deferred tax assets:		

Net operating loss	278.1	101.2
Tax credits	-	3.9
Other	2.7	3.5
Deferred tax assets before valuation allowance	$280.8	$108.6
Valuation allowance	(2.7)	(3.5)
Deferred tax assets	278.1	105.1
Deferred tax liabilities:		
Investments (1)	(768.9)	(1,002.6)
Property, plant, and equipment	(16.4)	(25.3)
Other	28.2	(18.4)
Deferred tax liabilities	(757.1)	(1,046.3)
Net deferred tax asset (liability)	$(479.0)	(941.2)
Net deferred tax asset (liability)		
Federal	$(386.1)	$(833.2)
Foreign	0.6	0.6
State	(93.5)	(108.6)
Long-term deferred tax liability, net	$(479.0)	$(941.2)

(1) Our deferred tax liability attributable to investments reflects the differences between the book and tax carrying values of our investment in the Partnership.

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"). The Tax Act makes broad and complex changes to the Internal Revenue Code of 1986, including, but not limited to, (1) reducing the U.S. federal corporate tax rate from 35% to 21%; (2) eliminating the corporate alternative minimum tax (AMT) and changing how existing AMT credits are realized; (3) creating a new limitation on deductible interest expense; and (4) changing rules related to uses and limitation of net operating loss carryforwards created in tax years beginning after December 31, 2017.

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 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.

In connection with our initial analysis of the impact of the Tax Act, we recorded a discrete net deferred tax benefit of $269.5 million in the period ending December 31, 2017. This net deferred tax benefit consists of the corporate tax rate reduction. For various reasons that are discussed more fully below, we have not completed our accounting for the income tax effects of certain elements of the Tax Act. We were able to make reasonable estimates that we recorded as provisional adjustments with regard to said elements.

Our accounting for the following elements of the Tax Act is complete:

- We reclassified $4.2 million of alternative minimum tax credits from deferred tax assets to long term assets. We expect to receive this amount as a refund in the years ended 2019, 2020 and 2021.

Our accounting for the following elements of the Tax Act is incomplete. However, we are able to make reasonable estimates of certain effects and, therefore, recorded provisional adjustments as follows:

- Reduction of U.S. federal corporate tax rate: The Tax Act reduces the corporate tax rate to 21%, effective January 1, 2018. We recorded a provisional deferred tax benefit of $269.5 million for the year ended December 31, 2017. While we are able to make a reasonable estimate of the impact of the reduction in corporate rate, it may be affected by other analyses related to the Tax Act including but not limited to changes to our cost recovery assumptions and the state tax effect of adjustments to federal temporary differences.
- Cost recovery: We have not yet completely inventoried and analyzed our 2017 capital expenditures that qualify for bonus expensing. We have recorded a provisional tax depreciation expense of $1.9 billion which does not include full expensing of all qualifying capital expenditures.
- Internal Revenue Code (“IRC”) Section 162(m) Limitations: Congress enacted several modifications to the compensation deduction limitation for covered employees under IRC Section 162(m). The modifications do not apply to compensation agreements entered into on or before November 2, 2017. Targa’s covered employees’ compensation is attributable to compensation agreements entered into on or before November 2, 2017. Consequently, we have not recorded a provisional adjustment as we continue to assess the applicability of the modifications in the context of Targa’s pre-November 2, 2017, compensation agreements and all facts and circumstances.

We have net operating loss carryforwards of $1.3 billion, which expire between 2036 and 2037.

As a result of the TRC/TRP Merger, TRC acquired all of the common units of the Partnership owned by the public. In exchange for said units, TRC transferred its stock with a fair market value as of the close of business February 16, 2016, of approximately $1.8 billion and TRC assumed TRP's liabilities of approximately $5.4 billion, resulting in a purchase price of $7.3 billion. The transaction constitutes a taxable sale which resulted in an adjustment to the tax basis in the underlying assets deemed acquired in the common partnership unit acquisition. A deferred tax liability of approximately $865.0 million related to the book tax basis difference in this investment has been recorded, computed as $4.1 billion book basis in excess of $1.8 billion tax basis at TRC's statutory rate of 37.34% at the time of the transaction.

As part of the TPL merger in 2015, we acquired TPL Arkoma Inc., a corporate subsidiary subject to federal and state income tax. Our corporate subsidiary accounts for income taxes under the asset and liability method and provides deferred income taxes for all significant temporary differences.

As of December 31, 2017, TPL Arkoma, Inc. had net operating loss carry forwards for federal income tax purposes of approximately $53.0 million, which expire at various dates from 2029 to 2037. Management believes it more likely than not that the deferred tax asset will be fully utilized.

Set forth below is the reconciliation between our income tax provision (benefit) computed at the United States statutory rate on income before income taxes and the income tax provision in our Consolidated Statements of Operations for the periods indicated:

Income tax reconciliation:	2017	2016	2015
Income (loss) before income taxes	$(292.9)	$(259.7)	$(111.8)
Less: Net income attributable to noncontrolling interest	(50.2)	(28.2)	209.7
Less: TPL Arkoma, Inc. income to TRC	—	0.8	0.5
Less: Income taxes included in noncontrolling interest	—	—	(0.6)
Income attributable to TRC (excluding TPL Arkoma, Inc.) before income taxes	(343.1)	(287.1)	97.8
Income from TPL Arkoma, Inc.	—	(0.8)	(7.6)
Income attributable to TRC and TPL Arkoma, Inc. before income taxes	(343.1)	(287.9)	90.2
Federal statutory income tax rate	35 %	35 %	35 %
Provision for federal income taxes	(120.1)	(100.8)	31.6
State income taxes, net of federal tax benefit	(11.7)	(6.1)	3.5
Amortization of deferred charge on 2010 transactions	—	4.7	4.7
Tax reform rate change	(269.5)	—	—
Other, net	4.2	1.6	(0.2)
Income tax provision (benefit)	$(397.1)	$(100.6)	$39.6

We have not identified any uncertain tax positions. We believe that our income tax filing positions and deductions will be sustained on audit and do not anticipate any adjustments that will result in a material adverse effect on our financial condition, results of operations or cash flow. Therefore, no reserves for uncertain income tax positions have been recorded.

Note 24 - Supplemental Cash Flow Information

	2017	2016	2015
Cash:			
Interest paid, net of capitalized interest (1)	$ 212.2	$ 282.0	$ 214.1
Income taxes paid, net of refunds	(67.5)	(10.6)	12.6
Non-cash investing activities:			
Deadstock commodity inventory transferred to property, plant and equipment	$ 9.0	$ 17.4	1.2
Impact of capital expenditure accruals on property, plant and equipment	205.4	27.6	43.8
Transfers from materials and supplies inventory to property, plant and equipment	3.6	2.4	3.7
Contribution of property, plant and equipment to investments in unconsolidated affiliates	1.0	—	—
Change in ARO liability and property, plant and equipment due to revised cash flow estimate	3.1	(9.1)	3.8
Deferred revenue related to property, plant and equipment received under contract amendment	—	—	22.6
Non-cash financing activities:			
Reduction of Owner's Equity related to accrued dividends on unvested equity awards under share compensation arrangements	$ 9.7	$ 8.7	1.6
Debt additions and retirements related to exchange of TRP 6 % Notes for 6 % TPL Notes	—	—	342.1
Allocation of Series A Preferred Stock net book value of BCF to additional paid-in capital	—	614.4	—
Change in accrued dividends of Series A Preferred Stock	—	—	0.9
Accrued dividends of Series A Preferred Stock	—	22.9	—
Accretion of deemed dividends on Series A Preferred Stock	25.7	18.2	—
Transfer within additional paid-in capital for exercise of Warrants	—	181.5	—
Impact of accounting standard adoption recorded in retained earnings	56.1	—	—
Non-cash balance sheet movements related to the Permian Acquisition (See Note 4 - Acquisitions and Divestitures):			
Contingent consideration recorded at the acquisition date	$ 416.3	$ —	$ —
Non-cash balance sheet movements related to the purchase of noncontrolling interests in subsidiary (See Note 4 - Acquisitions and Divestitures):			
Additional paid-in capital	(13.9)	65.0	—
Deferred tax liability	13.9	—	—
Noncontrolling interests	—	(65.0)	—
Additional paid-in capital	0.3	3,207.5	—
Accumulated other comprehensive income	—	55.8	
Noncontrolling interests	—	(4,119.7)	—
Deferred tax liability	(0.3)	856.3	—
Non-cash balance sheet movements related to the Atlas Merger (See Note 4 - Acquisitions and Divestitures):			
Non-cash merger consideration - common units and replacement equity awards	$ —	$ —	$ 2,436.1
Non-cash merger consideration - common shares and replacement equity awards	—	—	1,013.7
Net non-cash balance sheet movements excluded from consolidated statements of cash flows	—	—	3,449.8
Net cash merger consideration included in investing activities	—	—	1,574.4

Total fair value of consideration transferred	$ —	$ —	$ 5,024.2

(1) Interest capitalized on major projects was $14.3 million, $8.3 million and $13.2 million for the years ended December 31, 2017, 2016 and 2015.

Note 25 – Compensation Plans

2010 TRC Stock Incentive Plan

In December 2010, we 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. 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 a "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 our common stock upon issuance.

Restricted Stock in Lieu of Salary –During 2016, we issued on a quarterly basis, a total of 32,267 shares of restricted stock to two of our executives in lieu of all of their 2016 base salary. These awards vested one year from the date of each grant. The weighted average grant-date fair value of these shares of restricted stock was $41.43. The number of shares of restricted stock awarded was determined by dividing one-fourth of the officer's annual base salary by the average closing price of the shares of common stock for five trading days before the end of each quarter. There was no issuance of this type of awards in 2017.

Director Grants – The committee awarded our common stock to our outside directors. In 2017, 2016 and 2015, we issued 13,818, 24,234 and 6,429 shares of director grants with the weighted average grant-date fair value of $60.48, $16.45 and $86.49. These director grants vested upon issuance.

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 five years. In 2017, 2016 and 2015, we issued 1,193,942, 1,129,705 and 140,477 shares of RSUs with the weighted average grant-date fair value of $54.18, $27.87 and $83.54.

Restricted Stock in Lieu of Bonus – During 2017 and 2016, we issued 84,221 and 153,252 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 $55.94 and $26.34. These awards will cliff vest over three years.

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, 2016	1,368,250	$ 38.10
Granted	1,207,760	54.25
Forfeited	(16,330)	47.35
Vested	(130,882)	80.47
Outstanding at December 31, 2017	2,428,798	43.78

Performance Share Units

During 2017, we issued 113,901 shares of performance share units to executive management and employees for the 2017 compensation cycle that will vest on December 31, 2019. The performance share units granted under the 2010 TRC Plan are three-year equity-settled awards linked to the performance of shares of our 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 performance share units 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 performance share units equal to the target number awarded multiplied by the TSR performance factor, and vested performance share units will be settled by the issuance of Company common stock. The value of dividend equivalent rights will be paid in cash.

Compensation cost for equity-settled performance share units 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 performance share units 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 following table summarizes the performance share units 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, 2016	—	$ —
Granted	113,901	99.71
Outstanding at December 31, 2017	113,901	99.71

TRC Equity Compensation Plan

In 2007, both we and the Partnership adopted Long-Term Incentive Plans (each, an "LTIP") for employees, consultants, directors and non-employee directors of us and our affiliates who perform services for us or our affiliates. The awards under this plan included performance units, phantom units and director grants. The Partnership LTIP ("TRP LTIP") provided for, among other things, the grant of both cash-settled and equity-settled performance units. In connection with the TRC/TRP Merger, as of February 17, 2016, we assumed, adopted, and amended the TRP LTIP, and changed the name of the plan to the Targa Resources Corp. Equity Compensation Plan (as assumed, adopted and amended, the "TRC Equity Compensation Plan" or the "Plan"), and we assumed all Partnership obligations associated with the Plan existing prior to its assumption and adoption by us. The TRC Equity Compensation Plan allows for the grant of options, performance shares, restricted stocks, replacement stocks and other stock-based awards. The termination date for this plan was February 7, 2017.

Awards Under TRP LTIP

Performance Units

The performance units granted under the TRP LTIP were linked to the performance of the Partnership's common units. Performance unit awards granted under either LTIP may also include distribution equivalent rights. The TRP LTIP was administered by the board of directors of the general partner of TRP. Total units authorized under the TRP LTIP were 1,680,000.

Each performance unit entitled the grantee to the value of our common unit on the vesting date multiplied by a stipulated vesting percentage determined from our ranking in a defined peer group. The performance period for most awards was three years, except for certain awards granted in December 2013, which provided for two, three or four-year vesting periods. The grantee received the vested unit value in cash or common units depending on the terms of the grant. The grantee may also be entitled to the value of any DERs based on the notional distributions accumulated during the vesting period times the vesting percentage. Distribution equivalent rights were paid for both cash-settled and equity-settled performance units.

Compensation cost for equity-settled performance units was recognized as an expense over the performance period based on fair value at the grant date. Fair value was calculated using a simulated unit price that incorporates peer ranking. Distribution equivalent rights associated with equity-settled performance units 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 to estimate accruals throughout the vesting period. The weighted average grant date fair value of TRP LTIP performance units granted in 2015 were $34.48.

Phantom Units

In 2015, the Partnership granted phantom units under the LTIP to various employees of Targa. These phantom units were denominated with respect to its common units, but not otherwise linked to the performance of its common units. Their vesting periods vary from one year to five years. The distribution equivalent rights of the phantom units were accumulated to be paid in cash at the vesting dates. In 2015, the Partnership issued 25,162 phantom units with a weighted average grant date fair value of $36.87.

Replacement Phantom Units

In connection with the APL merger in 2015, the Partnership awarded replacement phantom units in accordance with and as required by the Atlas Merger Agreements to those APL employees who became Targa employees upon close of the acquisition. The vesting dates and terms remained unchanged from the existing APL awards, and will vest either 25% per year over the original four-year term or 33% per year over the original three-year term. The distribution equivalent rights of the replacement phantom units are paid in cash within 60 days of the payment of distributions. A total of 629,231 replacement phantom units were granted in 2015 with a weighted average grant date fair value of $43.82.

Partnership Director Grants

Starting in 2012, the common units granted to the Partnership's non-management directors vested immediately at the grant date. The weighted average grant date fair values of the director grants granted in 2016 and 2015 were $10.11 and $44.67. The fair values related to the units vested were $0.3 million and $0.5 million.

Impact of TRC/TRP Merger

The TRC/TRP Merger did not trigger the acceleration of any time-based vesting of any of the Partnership's outstanding long-term equity incentive compensation awards under the TRP LTIP. All outstanding performance unit awards previously granted under the TRP LTIP were converted and restated into comparable awards based on Targa's common shares. Specifically, each outstanding performance unit award was converted and restated, effective as of the effective time of the TRC/TRP Merger, into an award to acquire, pursuant to the same time-based vesting schedule and forfeiture and termination provisions, a comparable number of Targa common shares determined by multiplying the number of performance units subject to each award by the exchange ratio in the TRC/TRP Merger (0.62), rounded down to the nearest whole share, and the performance factor was eliminated.

At the time of the TRC/TRP Merger and immediately prior to the assumption and adoption of the Plan, the only outstanding awards under the TRP LTIP were equity-settled performance units and certain phantom units of the Partnership. All such outstanding awards were converted into comparable time-based RSUs based on our common stock. All amounts previously credited as distribution equivalent rights under any outstanding performance unit award continue to remain so credited and will be payable on the payment date set forth in the applicable award agreement, subject to the same time-based vesting schedule previously included in the performance unit award, but without application of any performance factor. The total employees affected by the amendment of the TRP LTIP were 363.

The February 17, 2016 conversion of 675,745 equity-settled performance units and 349,541 replacement phantom units outstanding to 418,906 equity-settled performance shares and 216,561 replacement phantom shares was considered modification of awards under ASC 718, Accounting for Stock-Based Compensation ("ASC 718"). The incremental change of $3.9 million in fair value between the original grant date fair value and the fair value as of February 17, 2016 is being recognized prospectively in general and administrative expense over the remaining service period of each award.

In addition to the conversion of TRP awards, we issued 331,282 restricted stock units under the Plan in 2016 which will cliff vest three years from the grant date. Of these 2016 grants, 310,809 RSUs were made in lieu of cash bonus for our nonexecutives. The grant-date fair value for the issuances was $74.01. In 2017, no restricted stock units were issued under the Plan.

The following table summarizes the restricted stock units for the year ended December 31, 2017, under the Plan:

	Restricted Stock Units	
	Number of shares	Weighted-average Grant-Date Fair Value
Outstanding as of December 31, 2016	700,402	$ 51.52
Forfeited	(16,416)	31.74
Vested	(186,039)	90.82
Outstanding as of December 31, 2017	497,947	40.54

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.

On February 17, 2016, as a result of the TRC/TRP Merger, 451,990 of TRP's outstanding cash-settled performance units were converted to 279,964 cash-settled restricted stock units under the TRC LTIP with performance factors eliminated. All amounts previously credited as distribution equivalent rights under any outstanding performance unit award continue to remain so credited and will be payable on the payment date set forth in the applicable award agreement, subject to the same time-based vesting schedule previously included in the performance unit award, but without application of any performance factor.

The February 17, 2016 conversion of outstanding cash-settled performance units to cash-settled restricted stock units was considered modification of awards under ASC 718. The incremental change in fair value between the original grant date fair value and the fair value as of February 17, 2016 resulted in recognition of additional compensation costs during the first quarter of 2016 of $4.8 million. Compensation expense for cash-settled performance units and any related DERs will ultimately be equal to the cash paid to the grantee upon vesting. However, throughout the vesting period we must record an accrued expense based on fair value of the stock on the last business day of the quarter.

The following table summarizes the cash-settled restricted stock units for the year ended December 31, 2017, under the TRC LTIP (in shares and millions of dollars).

	Program Year		
	2014 Awards	2015 Awards	Total
Outstanding as of December 31, 2016	72,979	116,316	189,295
Vested and paid	(71,752)	(1,183)	(72,935)
Forfeited	(1,227)	(2,583)	(3,810)
Outstanding as of December 31, 2017	-	112,550	112,550
Calculated fair market value as of December 31, 2017	$ -	$ 6,670,957	$ 6,670,957
Current liability	$ -	$ 5,473,782	$ 5,473,782
Long-term liability	-	-	-
Liability as of December 31, 2017	$ -	$ 5,473,782	$ 5,473,782
To be recognized in future periods	$ -	$ 1,197,175	$ 1,197,175
Vesting date	June 2017	June 2018	

The cash settled for the awards under TRC LTIP were $4.1 million, $4.8 million and $7.8 million for 2017, 2016 and 2015. The remaining weighted average recognition period for the unrecognized compensation cost is approximately 0.5 years.

Stock compensation expense under our plans totaled $44.2 million, $41.2 million, and $22.8 million for the years ended December 31, 2017, 2016, and 2015.

As of December 31, 2017, we have $81.5 million of unrecognized compensation expense associated with share-based awards and an approximate remaining weighted average vesting periods of 2.6 years related to our various compensation plans.

The fair values of share-based awards vested in 2017, 2016 and 2015 were $16.9 million, $19.8 million and $31.8 million, including cash dividends paid for the vested awards of $2.5 million, $2.7 million and $1.9 million. We recognized $1.1 million in tax benefits associated with the vesting of the awards in 2015.

Pursuant to ASU 2016-09, Compensation – Stock Compensation (Topic 718), Improvements to Employee Share-Based Payment Accounting, tax benefits of dividends on share-based payment awards should be recognized as income tax benefits or expenses in the income statement. We adopted the applicable amendments in the second quarter of 2016 and recognized $3.1 million and $0.5 million tax deficiencies as income tax expenses for the years ended December 31, 2017 and 2016. See Note 2 – Basis of Presentation.

Subsequent Events

In January 2018, the Compensation Committee of the Targa board of directors made the following awards under the 2010 TRC Plan.

- 16,184 shares of restricted stock to our outside directors that will vest in January 2019.
- 80,000 shares of RSUs to executive management for the 2018 compensation cycle that will vest 50% in December 2018 and 50% in December 2019.
- 192,598 shares of RSUs to executive management for the 2018 compensation cycle that will vest in January 2021.
- 182,849 shares of Performance Share Units to executive management for the 2018 compensation cycle that will vest in December 2020.
- 112,438 shares of RSUs in lieu of cash bonus to executive management for the 2018 compensation cycle that will vest in January 2021.

Targa 401(k) Plan

We have a 401(k) plan whereby we match 100% of up to 5% of an employee's contribution (subject to certain limitations in the plan). We also contribute an amount equal to 3% of each employee's eligible compensation to the plan as a retirement contribution and may make additional contributions at our sole discretion. All Targa contributions are made 100% in cash. We made contributions to the 401(k) plan totaling $16.5 million, $14.4 million and $13.8 million during 2017, 2016, and 2015.

Note 26 — Segment Information

We operate in two primary segments: (i) Gathering and Processing, and (ii) Logistics and Marketing (also referred to as the Downstream Business). Our reportable segments include operating segments that have been aggregated based on the nature of the products and services provided.

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

Our Logistics and Marketing segment includes all the activities necessary to convert mixed NGLs into NGL products and provides certain value added services such as storing, terminaling, distributing and marketing of NGLs, the storage and terminaling of refined petroleum products and crude oil and certain natural gas supply and marketing activities in support of our other businesses including services to LPG exporters. It also includes certain natural gas supply and marketing activities in support of our other operations, as well as transporting natural gas and NGLs. The Logistics and Marketing segment also includes Grand Prix, as well as our equity interest in GCX, which are both currently under construction.

Logistics and Marketing operations are generally connected to and supplied in part by our Gathering and Processing segment and, except for the pipeline projects and smaller terminals, are located predominantly in Mont Belvieu and Galena Park, Texas, and Lake Charles, Louisiana.

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

Reportable segment information is shown in the following tables:

	Year Ended December 31, 2017				
	Gathering and Processing	Logistics and Marketing	Other	Corporate and Eliminations	Total
Revenues					
Sales of commodities	$781.4	$ 6,979.3	$(9.6)	$ —	$7,751.1
Fees from midstream services	566.3	497.5	—	—	1,063.8
	1,347.7	7,476.8	(9.6)	—	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	$4,508.8	$ 7,826.7	$(9.6)	$ (3,511.0)	$8,814.9
Operating margin	$783.8	$ 511.8	$(9.6)	$ (0.1)	$1,285.9
Other financial information:					
Total assets (1)	$10,732.3	$ 3,507.4	$56.8	$ 92.1	$14,388.6
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 included in the Corporate and Eliminations column primarily include tax-related assets, cash, prepaids and debt issuance costs for our revolving credit facilities.

	Year Ended December 31, 2016				
	Gathering and Processing	Logistics and Marketing	Other	Corporate and Eliminations	Total
Revenues					
Sales of commodities	$621.9	$ 4,942.0	$62.9	$ —	$5,626.8
Fees from midstream services	486.6	577.5	—	—	1,064.1
	1,108.5	5,519.5	62.9	—	6,690.9
Intersegment revenues					
Sales of commodities	2,124.4	251.5	—	(2,375.9)	—
Fees from midstream services	7.8	23.5	—	(31.3)	—
	2,132.2	275.0	—	(2,407.2)	—

Revenues	$3,240.7	$ 5,794.5	$62.9	$ (2,407.2)	$6,690.9
Operating margin	$577.1	$ 574.4	$62.9	$ (0.1)	$1,214.3
Other financial information:					
Total assets (1)	$9,800.6	$ 2,868.7	$21.8	$ 180.1	$12,871.2
Goodwill	$210.0	$ —	$—	$ —	$210.0
Capital expenditures	$402.5	$ 185.3	$—	$ 4.3	$592.1

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

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	Year Ended December 31, 2015				
	Gathering and Processing	Logistics and Marketing	Other	Corporate and Eliminations	Total
Revenues					
Sales of commodities	$1,485.4	$ 3,895.8	$84.2	$ —	$5,465.4
Fees from midstream services	427.1	766.1	—	—	1,193.2
	1,912.5	4,661.9	84.2	—	6,658.6
Intersegment revenues					
Sales of commodities	1,126.3	208.9	—	(1,335.2)	—
Fees from midstream services	8.7	17.8	—	(26.5)	—
	1,135.0	226.7	—	(1,361.7)	—
Revenues	$3,047.5	$ 4,888.6	$84.2	$ (1,361.7)	$6,658.6
Operating margin	$515.1	$ 681.7	$84.2	$ —	$1,281.0
Other financial information:					
Total assets (1)	$10,391.9	$ 2,567.1	$127.1	$ 124.9	$13,211.0
Goodwill	$417.0	$ —	$—	$ —	$417.0
Capital expenditures	$496.3	$ 272.0	$—	$ 8.9	$777.2
Business acquisitions	$5,024.2	$ —	$—	$ —	$5,024.2

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

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

	2017	2016	2015
Sales of commodities:			
Natural gas	$2,002.0	$1,584.5	$1,578.6
NGL	5,418.0	3,777.3	3,558.3
Condensate	196.0	133.9	142.4
Petroleum products	144.7	68.2	101.6
Derivative activities	(9.6)	62.9	84.5
	7,751.1	5,626.8	5,465.4
Fees from midstream services:			
Fractionating and treating	132.8	126.2	209.0
Storage, terminaling, transportation and export	342.2	420.0	506.2
Gathering and processing	523.3	445.0	393.7

Other	65.5	72.9	84.3
	1,063.8	1,064.1	1,193.2
Total revenues	$8,814.9	$6,690.9	$6,658.6

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

	2017	2016	2015
Reconciliation of reportable segment operating margin to income (loss) before income taxes:			
Gathering and Processing operating margin	$ 783.8	$ 577.1	$ 515.1
Logistics and Marketing operating margin	511.8	574.4	681.7
Other operating margin	(9.6)	62.9	84.2
Depreciation and amortization expenses	(809.5)	(757.7)	(644.5)
General and administrative expenses	(203.4)	(187.2)	(161.7)
Impairment of property, plant and equipment	(378.0)	—	(32.6)
Impairment of goodwill	—	(207.0)	(290.0)
Interest expense, net	(233.7)	(254.2)	(231.9)
Other, net	45.7	(68.0)	(32.1)
Income (loss) before income taxes	$ (292.9)	$ (259.7)	$ (111.8)

Note 27 — Selected Quarterly Financial Data (Unaudited)

Our results of operations by quarter for the years ended December 31, 2017 and 2016 were as follows:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
2017					
Revenues	$2,112.6	$1,867.7	$2,131.8	$2,702.8	$8,814.9
Gross margin	458.4	447.1	468.7	534.6	1,908.8
Income (loss) from operations (1)	50.5	37.2	(323.6)	113.5	(122.4)
Net income (loss)	(110.5)	70.6	(155.1)	299.2	104.2
Net income (loss) attributable to common shareholders	(148.3)	28.4	(197.0)	253.5	(63.4)
Net income (loss) per common share - basic	(0.77)	0.14	(0.91)	1.17	(0.31)
Net income (loss) per common share - diluted (2)	(0.77)	0.14	(0.91)	1.05	(0.31)
2016					
Revenues	$1,442.4	$1,583.6	$1,652.3	$2,012.6	$6,690.9
Gross margin	431.4	438.4	429.6	468.6	1,768.0
Income (loss) from operations (3)(4)	35.5	66.3	51.6	(97.6)	55.8
Net income (loss)	(0.7)	(14.6)	(3.2)	(140.6)	(159.1)
Net income (loss) attributable to common shareholders	(6.5)	(52.6)	(39.4)	(179.6)	(278.1)
Net income (loss) per common share - basic	(0.06)	(0.33)	(0.23)	(0.99)	(1.80)
Net income (loss) per common share - diluted	(0.06)	(0.33)	(0.23)	(0.99)	(1.80)

(1) Includes a non-cash pre-tax impairment charge of $378.0 million in the third quarter of 2017. See Note 6 – Property, Plant and Equipment and Intangible Assets.
(2) Include dilutive effects of common stock equivalents in the second quarter of 2017 and fourth quarter of 2017. Dilutive effects of common stock equivalents were computed using the treasury method for warrants and unvested stock awards, and the if-converted method for the convertible preferred stock. Under the if-converted method, the dividends on the convertible preferred stock are added back to the numerator for the purposes of the diluted earnings per share calculation. For the periods with net income attributable to common shareholders, the anti-dilution sequencing rule was applied from the most dilutive to the least dilutive potential common shares.
(3) Includes a goodwill impairment of $24.0 million in the first quarter of 2016, which represented the finalization of the 2015 provisional charge. See Note 7 – Goodwill.
(4) Includes a goodwill impairment of $183.0 million in the fourth quarter of 2016. See Note 7 – Goodwill.

Note 28— Condensed Parent Only Financial Statements

The condensed parent only financial statements represent the financial information required by Rule 5-04 of the Securities and Exchange Commission Regulation S-X for Targa Resources Corp.

In the condensed financial statements, Targa's investments in consolidated subsidiaries are presented under the equity method of accounting. Under this method, the assets and liabilities of affiliates are not consolidated. The investments in net assets of the consolidated subsidiaries are recorded in the balance sheets. The income (loss) from operations of the consolidated subsidiaries is reported as equity in income (loss) of consolidated subsidiaries. Other comprehensive income has been adjusted for Targa's share of the investees' currently reported other comprehensive income.

A substantial amount of Targa's operating, investing and financing activities are conducted by its affiliates. The condensed financial statements should be read in conjunction with Targa's consolidated financial statements, which begin on page F-1 in this Annual Report.

TARGA RESOURCES CORP.
PARENT ONLY
CONDENSED BALANCE SHEETS

	December 31,	
	2017	2016
ASSETS		
Investment in consolidated subsidiaries	$ 6,804.2	$ 5,840.2
Deferred income taxes	39.9	54.5
Debt issuance costs	4.5	6.5
Total assets	$ 6,848.6	$ 5,901.2
LIABILITIES, SERIES A PREFERRED STOCK AND OWNERS' EQUITY		
Accrued current liabilities	$ 24.4	$ 23.6
Long-term debt	435.0	429.0
Other long-term liabilities	12.4	9.2
Contingencies		
Series A Preferred 9.5% Stock, net of discount	216.5	190.8
Targa Resources Corp. stockholders' equity	6,160.3	5,248.6
Total liabilities, Series A Preferred Stock and owners' equity	$ 6,848.6	$ 5,901.2

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TARGA RESOURCES CORP.
PARENT ONLY
CONDENSED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)

	Year Ended December 31,		
	2017	2016	2015
Equity in net income (loss) of consolidated subsidiaries	$ 103.3	$ (167.3)	$ 87.6
General and administrative expense	(12.9)	(10.0)	(8.0)
Income (loss) from operations	90.4	(177.3)	79.6
Other income (expense):			
Loss on debt extinguishment	(5.9)	—	(12.9)
Interest expense	(15.9)	(20.8)	(24.2)
Income (loss) before income taxes	68.6	(198.1)	42.5
Deferred income tax (expense) benefit	(14.6)	10.8	15.8
Net income (loss) attributable to Targa Resources Corp.	54.0	(187.3)	58.3
Other comprehensive income (loss)	8.4	(99.8)	0.9
Total comprehensive income (loss)	$ 62.4	$ (287.1)	$ 59.2
Dividends on Series A Preferred Stock	91.7	72.6	—
Deemed dividends on Series A Preferred Stock	25.7	18.2	—
Net income (loss) attributable to common shareholders	(63.4)	(278.1)	58.3
Net income (loss) attributable to Targa Resources Corp.	$ 54.0	$ (187.3)	$ 58.3

TARGA RESOURCES CORP.
PARENT ONLY
CONDENSED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2017	2016	2015
Net cash provided by operating activities	$ 115.1	$ 125.3	$ 62.6
Cash flows from investing activities			
Outlays for business acquisitions, net of cash acquired	—	—	(745.7)
Distribution and return of advances from consolidated subsidiaries	(912.9)	(921.0)	60.8
Net cash used in investing activities	(912.9)	(921.0)	(684.9)
Cash flows from financing activities			
Proceeds from long-term debt borrowings	965.0	612.0	914.5
Repayments of long-term debt	(965.0)	(777.0)	(424.0)
Costs incurred in connection with financing arrangements	(16.0)	(41.3)	(22.5)
Proceeds from issuance of common stock, preferred stock and warrants	1,660.4	1,571.4	335.5
Repurchase of common stock	(3.4)	(3.5)	(3.3)
Dividends paid to common and preferred shareholders	(843.2)	(565.9)	(179.0)
Excess tax benefit from stock-based awards	—	—	1.1
Net cash provided by financing activities	797.8	795.7	622.3
Net increase (decrease) in cash and cash equivalents	—	—	—
Cash and cash equivalents - beginning of year	—	—	—
Cash and cash equivalents - end of year	$ —	$ —	$ —