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, 2015

or

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

For the transition period from _____ to _____

Commission File Number: 001-33303

TARGA RESOURCES PARTNERS LP
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**65-1295427** (I.R.S. Employer Identification No.)
1000 Louisiana St. Suite 4300, Houston, Texas (Address of principal executive offices)	**77002** (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 Units Representing Limited Partnership Interests	New York Stock Exchange
9.00% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units	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, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting 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 ☐

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

The aggregate market value of the common units representing limited partner interests held by non-affiliates of the registrant was approximately $6,669.0 million on June 30, 2015, based on $71.92 per unit, the closing price of the common units as reported on the New York Stock Exchange (NYSE) on such date.

As of February 17, 2016, there were 184,899,602 common units and 3,773,461 general partner units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None

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CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Targa Resources Partners LP's (together with its subsidiaries, "we," "us," "our," "TRP" or "the Partnership") reports, filings and other public announcements may from time to time contain statements that do not directly or exclusively relate to historical facts. Such statements are "forward-looking statements." You can typically identify forward-looking statements by the use of forward-looking phrases, such as "may," "could," "project," "believe," "anticipate," "expect," "estimate," "potential," "plan," "forecast" and other similar words.

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

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

- the timing and extent of changes in natural gas, natural gas liquids ("NGL"), crude oil and other commodity prices, interest rates and demand for our services;
- our ability to access the capital markets, which will depend on general market conditions and the credit ratings for our debt obligations;
- 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;
- 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;
- 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 NGL supplies to our logistics and marketing facilities and our success in connecting our facilities to transportation and markets;
- our ability to grow through acquisitions or internal growth projects and the successful integration and future performance of such assets; including with respect to the Atlas mergers (as defined below) which were completed on February 27, 2015 between Targa Resources Corp. ("Targa," "Parent" or "TRC") and Atlas Energy, L.P., a Delaware limited partnership ("ATLS") and between Atlas Pipeline Partners, L.P., a Delaware limited partnership ("APL") and us;
- general economic, market and business conditions; and
- the risks described elsewhere in "Item 1A. Risk Factors." in this Annual Report and our reports and registration statements filed from time to time with the United States Securities and Exchange Commission ("SEC").

Although we believe that the assumptions underlying our forward-looking statements are reasonable, any of the assumptions could be inaccurate, and, therefore, we cannot assure you that the forward-looking statements included in this Annual Report will prove to be accurate. Some of these and other risks and uncertainties that could cause actual results to differ materially from such forward-looking statements are more fully described in "Item 1A. Risk Factors." in this Annual Report. Except as may be required by applicable law, we undertake no obligation to publicly update or advise of any change in any forward-looking statement, whether as a result of new information, future events or otherwise.

As generally used in the energy industry and in this Annual Report, the identified terms have the following meanings:

Bbl	Barrels (equal to 42 U.S. gallons)
Bcf	Billion cubic feet
Btu	British thermal units, a measure of heating value
BBtu	Billion British thermal units
/d	Per day
/hr	Per hour
gal	U.S. gallons
GPM	Liquid volume equivalent expressed as gallons per 1000 cu. ft. of natural gas
LPG	Liquefied petroleum gas
MBbl	Thousand barrels
MMBbl	Million barrels
MMBtu	Million British thermal units
MMcf	Million cubic feet
NGL(s)	Natural gas liquid(s)
NYMEX	New York Mercantile Exchange
GAAP	Accounting principles generally accepted in the United States of America
LIBOR	London Interbank Offered Rate
NYSE	New York Stock Exchange

Price Index Definitions

IF-NGPL MC	Inside FERC Gas Market Report, Natural Gas Pipeline, Mid-Continent
IF-PB	Inside FERC Gas Market Report, Permian Basin
IF-WAHA	Inside FERC Gas Market Report, West Texas WAHA
NY-WTI	NYMEX, West Texas Intermediate Crude Oil
OPIS-MB	Oil Price Information Service, Mont Belvieu, Texas
NG-NYMEX	NYMEX, Natural Gas

PART I

Item 1. Business.

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

Targa Resources Partners LP (NYSE:NGLS) is a Delaware limited partnership formed in October 2006 by our parent, Targa Resources Corp. ("Targa" or "TRC" or the "Company" or "Parent"), to own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets. TRP is a leading provider of midstream natural gas and NGL services in the United States, with a growing presence in crude oil gathering and petroleum terminaling.

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

At the effective time of the TRC/TRP Merger, each outstanding TRP common unit not owned by TRC or its subsidiaries was converted into the right to receive 0.62 shares of common stock of TRC, par value $0.001 per share ("TRC shares"). 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 has agreed to cause our common units to be delisted from the New York Stock Exchange ("NYSE") and deregistered under the Securities Exchange Act of 1934, as amended (the "Exchange Act"). As a result of the completion of the TRC/TRP Merger, our common units are no longer publicly traded. The 9.00% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Preferred Units") remain outstanding as limited partner interests in us and continue to trade on the NYSE under the symbol "NGLS PRA."

We are engaged in the business of:

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

To provide these services, we operate in two primary divisions: (i) Gathering and Processing, consisting of two reportable segments—(a) Field Gathering and Processing and (b) Coastal Gathering and Processing; and (ii) Logistics and Marketing (also referred to as our Downstream Business), consisting of two reportable segments—(a) Logistics Assets and (b) Marketing and Distribution. For a detailed description of these businesses, please see "—Our Business Operations."

Our midstream natural gas and NGL services footprint was initially established through several acquisitions from Targa, totaling $3.1 billion, that occurred from 2007 through 2010, and was expanded through third-party acquisitions including 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 and our 2015 acquisition of Atlas Pipeline Partners, L.P. ("APL"). In these transactions we acquired (1) natural gas gathering, processing and treating assets in North Texas, West Texas, South Texas, Oklahoma, North Dakota, New Mexico and the Louisiana Gulf Coast, (2) crude oil gathering and terminal assets in North Dakota and (3) NGL assets consisting of fractionation, transport, storage and terminaling facilities, low sulfur natural gasoline treating facilities ("LSNG"), pipeline transportation and distribution assets, propane storage and truck terminals primarily located near Houston, Texas and in Lake Charles, Louisiana.

Since the completion of the final acquisitions from Targa in 2010 and with our 2015 acquisition of APL we have grown substantially, with large increases in a number of metrics as of year-end 2015, including total assets (313%), adjusted earnings before interest, taxes, depreciation and amortization (“EBITDA”) (201%), distributable cash flow (214%) and distributions per unit to our common unitholders (51%). The expansion of our business has been fueled by a combination of major organic growth investments in our businesses and acquisitions.

Organic Growth Projects

We continue to invest significant capital to expand through organic growth projects. We have invested approximately $3.3 billion in growth capital expenditures since 2007, including approximately $0.7 billion in 2015. These expansion investments were distributed across our businesses, with 52% related to Logistics and Marketing and 48% to Gathering and Processing. We will continue to invest in both large and small organic growth projects in 2016, including the current fractionation expansion of our 88% owned Cedar Bayou Fractionator (“CBF”) in Mont Belvieu, Texas. We expect that the amount of capital expenditures will be less than previous years due to current market conditions, and the reduced level of drilling activity around our areas of operations. Depending on the ultimate level of industry activity, we currently estimate that we will invest $525 million or less in growth capital expenditures for announced projects in 2016.

Atlas Mergers

On February 27, 2015, Targa completed the acquisition of Atlas Energy LP (“ATLS”), a Delaware limited partnership, and the Partnership completed the acquisition of APL, a Delaware limited partnership (the “Atlas mergers”). 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 play in south Texas. The Atlas mergers added TPL’s Woodford/South Central Oklahoma Oil Province (“SCOOP”), Mississippi Lime, Eagle Ford and additional Permian assets to the Partnership’s existing operations. In total, TPL adds 2,053 MMcf/d of processing capacity and 12,220 miles of additional pipeline. The results of TPL are reported in our Field Gathering and Processing segment.

Pursuant to the amendment to our partnership agreement entered into by our general partner in conjunction with the Atlas mergers (the “IDR Giveback Amendment”), IDRs of $9.375 million were allocated to common unitholders for each quarter of 2015 commencing with the first quarter of 2015. The IDR Giveback Amendment covers sixteen quarters following the completion of the Atlas mergers on February 27, 2015 resulted in reallocation of IDR payments to common unitholders –in the amount of $9.375 million per quarter for 2015, and will result in reallocation of IDR payments to common unitholders in the amount of $6.25 million in the first quarter of 2016.

2015 Developments

Volatility of Commodity Prices

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 decrease as crude oil and natural gas prices decrease below commercially acceptable levels. Prices of oil and natural gas have been historically volatile, and we expect this volatility to continue. Our operations are affected by the level of crude, natural gas and NGL prices, the relationship between these prices and related reduced activity levels from our customers. The duration and magnitude of the decline in market prices cannot be predicted.

Logistics Assets Segment Expansions

Cedar Bayou Fractionator Train 5

In July 2014, we approved construction of a 100 MBbl/d fractionator at CBF. The 100 MBbl/d expansion will be 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. Construction has been underway and is continuing and we expect completion of construction in the second quarter of 2016. Construction of the expansion has proceeded without disruption to existing operations, and we estimate that total growth capital expenditures net to our 88% interest for the expansion and the related infrastructure enhancements at Mont Belvieu should approximate $340 million.

Channelview Splitter

On December 27, 2015 Targa Terminals LLC ("Targa Terminals") and Noble Americas Corp., a subsidiary of Noble Group Ltd. ("Noble") entered into a long-term, fee-based agreement (“Splitter Agreement”) under which Targa Terminals will build and operate a 35,000 barrel per day crude and condensate splitter at Targa Terminals’ Channelview Terminal on the Houston Ship Channel (“Channelview Splitter”). The Channelview Splitter will have the capability to split approximately 35,000 barrels per day of 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 is expected to be completed by early 2018, and has an estimated total cost of approximately $130 million to $150 million. Our current total project capital expenditures estimate is higher than the original announcement in March 2014 because of changes in project scope and anticipated increases in costs for engineering, procurement and construction services and/or materials, including labor costs. As contemplated by the agreement entered into on December 31, 2014 between Targa Terminals and Noble (the “December 2014 Agreement”), the Splitter Agreement completes and terminates the December 2014 Agreement while retaining our economic benefits from that agreement.

Field Gathering and Processing Segment Expansion

Badlands Little Missouri 3

In the first quarter of 2015, we completed the 40 MMcf/d Little Missouri 3 plant expansion in McKenzie County, North Dakota, that increased capacity to 90 MMcf/d.

Permian Basin Buffalo Plant

In April 2014, TPL announced plans to build a new plant and expand the gathering footprint of its WestTX system. This project includes the laying of a new high pressure gathering line into Martin and Andrews counties of Texas, as well as incremental compression and a new 200 MMcf/d cryogenic processing plant, known as the Buffalo plant. Although construction was suspended for a period of time to assess supply uncertainties, it is now expected to be completed during the second quarter of 2016. Total growth capital expenditures for the Buffalo plant should approximate $105 million.

Eagle Ford Shale Natural Gas Processing Joint Venture

In October 2015, we announced that we entered into joint venture agreements with Sanchez Energy Corporation (“Sanchez”) to construct a new 200MMcf/d cryogenic natural gas processing plant in La Salle County, Texas (the “Raptor Plant”) and approximately 45 miles of associated pipelines. We expect to invest approximately $125 million of growth capital expenditures related to the joint ventures, and have a 50% ownership interest in the plant and the approximately 45 miles of high pressure gathering pipelines that will connect Sanchez's Catarina gathering system to the plant. We hold a portion of the transportation capacity on the pipeline, and the gathering joint venture receives fees for transportation.

The Raptor Plant will accommodate the 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 lines are supported by long-term, firm, fee-based contracts and acreage dedications with Sanchez. We will manage construction and operations of the plant and high pressure gathering lines, and the plant is expected to begin operations in early 2017. Prior to the plant being placed in-service, we will benefit from Sanchez natural gas volumes that will be processed at our Silver Oak facilities in Bee County, Texas.

In addition to the major projects in process noted above, we potentially have other growth capital expenditures in 2016 related to the continued build out of our gathering and processing infrastructure and logistics capabilities. In the current depressed commodity price environment we will evaluate these potential projects based on return profile, capital requirements and strategic need and may choose to defer projects depending on expected activity levels.

Financing Activities

In January 2015, we issued $1.1 billion in aggregate principal amount of 5% Notes due 2018 (the “5% Notes”). The $1,089.8 million of net proceeds were used together with borrowings from our senior secured revolving credit facility (the “TRP Revolver”) to fund the APL Notes Tender Offers and the Change of Control Offer (both as defined herein)..

In February 2015, we amended our TRP Revolver to increase available commitments to $1.6 billion from $1.2 billion while retaining the right to request up to an additional $300.0 million in commitment increases. In connection with the 58,614,157 common units issued in the Atlas mergers in February 2015, Targa contributed an additional $52.4 million to us to maintain its 2% general partner interest.

In May 2015, we entered into an equity distribution agreement (the “May 2015 EDA”), pursuant to which we may sell through our sales agents, at our option, up to an aggregate of $1.0 billion of our common units. During the twelve months ended December 31, 2015, we issued 7,377,380 total common units under our equity distribution agreements (“EDAs”), receiving proceeds of $316.1 million (net of commissions). As of December 31, 2015, approximately $4.2 million of capacity and $835.6 million of capacity remain under our 2014 equity distribution agreement (“the May 2014”) and May 2015 EDAs. During the twelve months ended December 31, 2015, pursuant to the issuance of units under our EDAs, Targa contributed $6.5 million to us to maintain its 2% general partner interest.

In May 2015, we issued $342.1 million aggregate principal amount of Senior Notes due 2020 to holders of APL 6⅝% Notes due 2020, which were validly tendered for exchange.

In September 2015, we issued $600.0 million in aggregate principal amount of 6¾% Senior Notes due 2014 (the “6¾% Notes”) resulting in approximately $595.0 million of net proceeds, which were used to reduce borrowings under the TRP Revolver and for general partnership purposes.

In October 2015, we completed an offering of 4,400,000 Preferred Units at a price of $25.00 per unit. We sold an additional 600,000 Preferred Units pursuant to the exercise of the underwriters’ overallotment option. We received net proceeds of approximately $121.1 million. We used the net proceeds from this offering to reduce borrowings under the TRP Revolver and for general partnership purposes. As of December 31, 2015, we have paid $1.5 million in distributions to our preferred unitholders. See Note 11 - Partnership Units and Related Matters.

In December 2015, we amended our account receivable securitization facility to extend the maturity to December 9, 2016 with a facility size of $225 million.

In December 2015, we repurchased on the open market a portion of outstanding Senior Notes as follows (the “December 2015 Senior Notes Repurchases”):

- 5¼% Notes due 2023 (the “5¼% Notes”) paying $13.0 million plus accrued interest to repurchase $16.3 million of the outstanding balance of the 5¼% Notes.

- 4¼% Notes due 2023 (the “4¼% Notes”) paying $1.2 million plus accrued interest to repurchase $1.5 million of the outstanding balance of the 4¼% Notes.

- 6⅝% APL Notes due 2020 (the “6⅝% Notes”) paying $0.1 million plus accrued interest to repurchase $0.1 million of the outstanding balance of the 6⅝% Notes.

The December 2015 Senior Note Repurchases resulted in a $3.6 million gain on debt repurchases and a corresponding write-off of $0.1 million in related deferred debt issuance costs.

Growth Drivers

We believe 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 for our Downstream Business. We believe our assets are not easily duplicated, and even in the current depressed commodity price environment, are located in many of the most attractive and active areas of explorations 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 third-party acquisitions will also continue to be a focus of our growth strategy.

Attractive Asset Positions

We believe that, despite continued declines in market prices for crude oil, natural gas and NGLs that have led to declines in producer activity, our position in some of the most attractive basins will allow us to capture increased natural gas supplies for processing. As commodity prices have declined, producers have focused drilling activity on their most profitable acreage, especially in the Permian Basin where we have a large and well-positioned footprint and expect to see continued, though lower level activity even in the current depressed commodity price environment.

The development of shale and resources 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 have added 178 MBbl/d of additional fractionation capacity with the additions of CBF Trains 3 and 4, and will complete construction of CBF Train 5 which is expected to add an additional 100 MBbl/d of fractionation capacity starting in the second quarter of 2016. We also funded our share of the NGL fractionation expansion at Gulf Coast Fractionators (“GCF”) in 2012. In periods of strong demand, fractionation service providers benefit from long-term, “take-or-pay” contracts for new and existing fractionation capacity. 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 long-term 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, 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 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.

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, provides us with a competitive advantage relative to other gathering and processing companies without these capabilities.

Bakken Shale / Three Forks opportunities

Although the declining commodity prices have reduced producer activity in the Bakken Shale and Three Forks plays in the Williston Basin, we have increased our volumes of crude oil gathered and natural gas gathered and processed. We continue to expand our infrastructure to capture additional volumes from wells that have already been drilled but that are not yet connected to our system.

Eagle Ford opportunities

As a result of our joint venture agreements with Sanchez in South Texas to construct a new 200 MMcf/d cryogenic processing plant and the associated infrastructure to connect to the Sanchez Catarina gathering system, we expect to benefit from increasing Sanchez production in the Eagle Ford play at our Silver Oak facilities prior to completion of the Raptor Plant and at the Raptor Plant thereafter.

Third party acquisitions

While our growth through 2010 was primarily driven by the implementation of a focused drop down strategy, we and Targa also have a record of completing third party acquisitions. Since our formation, our strategy included approximately $12.6 billion in acquisitions and growth capital expenditures of which approximately $6.2 billion was for acquisitions (including the APL merger) from third-parties. We expect that third-party acquisitions will continue to be a focus of our growth 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 generally 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 asset are driven primarily by oil well economics. If drilling and production activities in these areas continue, we would likely increase the volumes of natural gas and crude oil available to our gathering and processing systems.

Leading fractionation, LPG export and NGL infrastructure position

We are one of the largest fractionators of NGLs in the Gulf Coast. Our primary fractionation assets are 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 connection 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, and our Galena Park marine export/import 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. The location and interconnectivity of these assets are not easily replicated, and we have sufficient 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 and to gather, process and treat wellhead gas to meet pipeline standards and to extract NGLs for sale into petrochemical, industrial, commercial and export markets. We believe our ability to provide these integrated services provides an advantage in competing for new supplies because we can provide substantially all of the services producers, marketers and others require for moving natural gas and NGLs from wellhead to market on a cost-effective basis. Additionally, we believe that 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, the difficulty of permitting and constructing new midstream assets 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 intend to 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 $83.2 million per year over the last four years, which included $20.4 million of maintenance capital from TPL in the last ten months of 2015. 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 services under attractive contract terms to a diverse mix of customers across our areas of operation. Consequently, we are not dependent on any one oil and gas basin or customer. 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.

Financial Flexibility

We have historically maintained a conservative leverage ratio and ample 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 Targa 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 provide 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 Field Gathering and Processing segment has a contract mix that is primarily percent-of-proceeds, but also has increasing components of fee-based revenues from some fee-based basins, from fees added to percent-of-proceeds contracts for natural gas treating and compression, from new/amended contracts with a combination of percent-of-proceeds and fee-based and from essentially fully fee-based crude oil gathering and gas gathering and processing in our Williston Basin and SouthTX assets. 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 through 2018 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 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. While recent commodity price levels have impacted 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. Our existing infrastructure has the capacity to handle some incremental increases in volumes without significant investments as well as opportunities to leverage existing assets with meaningful expansions. 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 or impact the amount of distributions to limited partners. These risks include the adverse impact of changes in natural gas, NGL and condensate/crude oil prices or in 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."

Relationship with Targa

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

As of December 31, 2015, Targa and its named executive officers and directors had a significant ownership interest in us through their ownership of approximately 9.1% limited partner interest and Targa's 2% general partner interest. As a result of the TRC/TRP Merger, which was completed on February 17, 2016, Targa owns all of our outstanding common units and the IDRs. The Partnership Agreement governs our relationship regarding certain reimbursement and indemnification matters. See "Item 13. Certain Relationships and Related Transactions and Director Independence."

We do not have any employees to carry out our operations. Targa employs approximately 1,870 people. See "—Employees." Targa charges us for all the direct costs of the employees assigned to our operations, as well as all general and administrative support costs other than its direct support costs of being a separate reporting company and its cost of providing management and support services to certain unaffiliated spun-off entities. We generally reimburse Targa for cost allocations to the extent that they have required a current cash outlay by Targa.

Our Challenges

We face a number of challenges in implementing our business strategy. For example:

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

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

- Our growth strategy requires access to new capital. Volatile capital markets with uncertain access or increased competition for investment opportunities could impair our ability to grow.

- Our long-term success depends on our ability to obtain new sources of supplies of natural gas, crude oil and NGLs, which is subject to certain factors beyond our control. Any decrease in supplies of natural gas, crude oil or NGLs could adversely affect our business and operating results.

- Although we believe we have a large, diverse customer base, we are subject to counterparty risk which could adversely affect our financial position.

- 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.

- If we do not successfully make acquisitions on economically acceptable terms or efficiently and effectively integrate assets from acquisitions, our results of operations and financial condition could be adversely affected.

- We are subject to regulatory, environmental, political, legal and economic risks, which could adversely affect our results of operations and financial condition.

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

For a further discussion of these and other challenges we face, please read "Item 1A. Risk Factors."

Our Business Operations

Our operations are reported in two divisions: (i) Gathering and Processing, consisting of two segments—(a) Field Gathering and Processing and (b) Coastal Gathering and Processing; and (ii) Logistics and Marketing, consisting of two segments—(a) Logistics Assets and (b) Marketing and Distribution.

Gathering and Processing Division

Our Gathering and Processing Division 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.

We believe our extensive asset base and scope of operations in the regions in which we operate provide us with significant opportunities to add both new and existing natural gas and crude oil production to our areas of operations. We believe our size and scope give us a strong competitive position through close proximity to a large number of existing and new producing wells in our areas of operations, allowing us to generate economies of scale and to provide our customers with access to our existing facilities and to end-use markets and market hubs. Additionally, we believe our ability to serve our customers' needs across the natural gas and NGL value chain further augments our ability to attract new customers.

Field Gathering and Processing Segment

The Field 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; and the Williston Basin in North Dakota.

The natural gas processed in this segment is supplied through our gathering systems which, in aggregate, consist of approximately 23,630 miles of natural gas pipelines and include 28 owned and operated processing plants. During 2015, we processed an average of 2,344.2 MMcf/d of natural gas and produced an average of 223.6 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.

We believe we are well positioned as a gatherer and processor in the Permian Basin, Eagle Ford Shale, Barnett Shale, Anadarko, Ardmore, Arkoma and Williston Basins. We believe proximity to production and development activities allows us to compete for new supplies of natural gas and crude oil partially because of our lower competitive cost to connect new wells and to process additional natural gas in our existing processing plants and because of our reputation for reliability. Additionally, because we operate all of our plants, which are often interconnected in these regions, we are often able to redirect natural gas among our processing plants, providing operational flexibility and allowing us to optimize processing efficiency and further improve the profitability of our operations.

The Field Gathering and Processing segment’s operations consist of SAOU, WestTX, Sand Hills, Versado, SouthTX, North Texas, SouthOK, WestOK and Badlands, each as described below:

SAOU

SAOU includes approximately 1,650 miles of pipelines in the Permian Basin that gather natural gas for delivery to the Mertzon, Sterling, Conger and High Plains processing plants. SAOU is connected to thousands of producing wells and over 840 central delivery points. SAOU’s processing facilities are refrigerated cryogenic processing plants with an aggregate processing capacity of approximately 369 MMcf/d. These plants have residue gas connections to pipelines owned by affiliates of Atmos Energy Corporation (“Atmos”), Enterprise Products Partners L.P. (“EPD”), Kinder Morgan, Inc. (“Kinder Morgan”), Northern Natural Gas Company (“Northern”) and ONEOK, Inc. (“ONEOK”).

WestTX

The WestTX gathering system has approximately 4,050 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 five separate plants: the Consolidator, Driver, Midkiff, Benedum and Edward processing facilities. The WestTX processing operations have an aggregate processing name-plate capacity of approximately 655 MMCF/D. To facilitate increased Spraberry production, we are constructing a new 200 MMCF/D cryogenic processing plant, known as the Buffalo plant, which is expected to be placed in service during the second quarter of 2016. The Buffalo plant will increase the WestTX aggregate processing name-plate capacity to approximately 855 MMCF/D.

The WestTX system has access has access to natural gas take-away pipelines owned by Atmos; El Paso Natural Gas Company; Kinder Morgan Tejas Pipeline, LLC; Enterprise Interstate, LLC; and Northern. On January 1, 2016, we began selling our NGL production at WestTX to our Downstream Business.

Sand Hills

The Sand Hills operations consist of the Sand Hills and Puckett gathering systems in West Texas. These systems consist of approximately 1,550 miles of natural gas gathering pipelines. These gathering systems are primarily low-pressure gathering systems with significant compression assets. The Sand Hills refrigerated cryogenic processing plant has a gross processing capacity of 165 MMcf/d and residue gas connections to pipelines owned by affiliates of EPD, Kinder Morgan and ONEOK.

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 3,450 miles of natural gas gathering pipelines. The Saunders, Eunice and Monument refrigerated cryogenic processing plants have aggregate processing capacity of 240 MMcf/d (151 MMcf/d, net to our ownership interest). These plants have residue gas connections to pipelines owned by affiliates of Kinder Morgan and MidAmerican Energy Company. Our ownership in Versado is held through Versado Gas Processors, L.L.C., a consolidated joint venture that is 63% owned by us and 37% owned by Chevron U.S.A. Inc.

SouthTX

The SouthTX gathering system includes approximately 550 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 175 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 system processes natural gas through the Silver Oak I and II processing plants. The Silver Oak I and II facilities are each 200 MMcf/d cryogenic plants located in Bee County, Texas. We own 90% of the Silver Oak II processing plant and Sanchez owns the remaining interest. The SouthTX system includes our 50% interest in Carnero Gathering, LLC and our 50% interest in Carnero Processing, LLC (together, the "Carnero Joint Ventures"). Sanchez owns the remaining interest in the Carnero Joint Ventures. The Carnero Joint Ventures were formed in October 2015 for the purposes of constructing a 200 MMcf/d cryogenic plant and approximately 45 miles of high pressure gathering pipelines that will connect Sanchez's Catarina gathering system to the new plant. We are currently constructing the Carnero processing and gathering facilities and will operate them after completion.

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 take-away pipelines owned by Enterprise Intrastate, LLC; Kinder Morgan Tejas Pipeline LLC, Natural Gas Pipeline Company of America, Tennessee Gas Pipeline Company, LLC, and Transcontinental Gas Pipe Line. We sell a portion of our NGL production at SouthTX to DCP Midstream Partners LP ("DCP") under a legacy Atlas exchange contract, which expires in 2029. The remaining portion of NGL production at SouthTX is purchased by our Downstream Business.

North Texas

North Texas includes two interconnected gathering systems in the Fort Worth Basin, including the Barnett Shale and Marble Falls plays, with approximately 4,550 miles of pipelines gathering wellhead natural gas for the Chico, Shackelford and Longhorn natural gas processing facilities. These plants have residue gas connections to pipelines owned by affiliates of Atmos, Energy Transfer Fuel LP and EPD.

The Chico gathering system consists of approximately 2,550 miles of gathering pipelines located in the Montague, Wise and Clay Counties in North Texas. Wellhead natural gas is either gathered for the Chico or Longhorn plants located in Wise County, Texas, and then compressed for processing, or it is compressed in the field at numerous compressor stations and then moved via one of several high-pressure gathering pipelines to the Chico or Longhorn plants. The Chico plant has an aggregated processing capacity of 265 MMcf/d and an integrated fractionation capacity of 15 MBbl/d. The Longhorn plant has a capacity of 200 MMcf/d. The Shackelford gathering system includes approximately 2,000 miles of gathering pipelines and gathers wellhead natural gas largely for the Shackelford plant in Albany, Texas. Natural gas gathered from the northern and eastern portions of the Shackelford gathering system is typically compressed in the field at numerous compressor stations and then transported to the Chico plant for processing. The Shackelford plant has an aggregate 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 six separate processing plants: Velma, Velma V-60, Coalgate, Atoka, Stonewall and Tupelo. The SouthOK processing operations have a total name-plate capacity of 580 MMcf/d. The Coalgate, Atoka and Stonewall facilities are owned by 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.

The SouthOK system has access to natural gas take-away pipelines owned by Enable Oklahoma Intrastate Transmission, LLC; MPLX, LP; Natural Gas Pipeline Company of America; ONEOK; and Southern Star Central Gas Pipeline, Inc. We sell our NGL production at SouthOK to ONEOK under two separate agreements. The Velma agreement has a primary term expiring at the end of 2016. A portion of the Arkoma agreement has a term expiring in 2018, with the remainder having a primary term that expires in 2024. We will sell our NGL production from the Velma processing facilities to our Downstream Business upon the expiration of the Velma ONEOK agreement. These NGL sales agreements were assumed as part of the Atlas mergers.

WestOK

The WestOK gathering system is located in north central Oklahoma and southern Kansas' Anadarko Basin. The gathering system has approximately 6,100 miles of natural gas gathering pipelines.

The WestOK system processes natural gas through three separate cryogenic natural gas processing plants at the Waynoka I and II and the Chester facilities; and one refrigeration plant at the Chaney Dell facility. The WestOK system has access to natural gas take-away pipelines owned by Enogex LLC; Panhandle Eastern Pipe Line Company, LP; and Southern Star Central Gas Pipeline, Inc. On January 1, 2016, we began selling our NGL production at WestOK to our Downstream Business.

Badlands

The Badlands operations are located in the Bakken and Three Forks Shale plays of the Williston Basin in North Dakota and include approximately 350 miles of crude oil gathering pipelines, 40 MBbl of operational crude storage capacity at the Johnsons Corner Terminal, 30 MBbl of operational crude 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 180 miles of natural gas gathering pipelines and the Little Missouri natural gas processing plant with a gross processing capacity of approximately 90 MMcf/d. A third train was installed at the Little Missouri plant site which increased processing capacity by an incremental 40 MMcf/d and was completed in January 2015 bringing total processing capacity to approximately 90 MMcf/d.

The following table lists the Field Gathering and Processing segment's processing plants and related volumes for the year ended December 31, 2015:

Facility	% Owned	Location	Estimated Gross Processing Capacity (MMcf/d)(1)	Reported Plant Natural Gas Inlet Throughput Volume (MMcf/d) (2) (3)	Gross NGL Production (MBbl/d) (2) (3)	Process Type (4)	
SAOU							
Mertzon	100.0	Irion, TX	52.0			Cryo	Operated
Sterling	100.0	Sterling, TX	92.0			Cryo	Operated
Conger (3)	100.0	Sterling, TX	25.0			Cryo	Operated
High Plains	100.0	Midland, TX	200.0			Cryo	Operated
		Area Total	369.0	234.0	27.3		
WestTX (5)							
Consolidator plant	72.8	Midkiff, TX	150.0			Cryo	Operated
Driver plant	72.8	Midland, TX	200.0			Cryo	Operated
Midkiff plant	72.8	Midkiff, TX	60.0			Cryo	Operated
Benedum plant (6)	72.8	Midkiff, TX	45.0			Cryo	Operated
Edward plant	72.8	Midkiff, TX	200.0			Cryo	Operated
		Area Total	655.0	374.0	43.4		
Sand Hills							
Sand Hills	100.0	Crane, TX	165.0			Cryo	Operated
		Area Total	165.0	163.0	17.4		
Versado (7) (8)							
Saunders	63.0	Lea, NM	60.0			Cryo	Operated
Eunice	63.0	Lea, NM	95.0			Cryo	Operated
Monument	63.0	Lea, NM	85.0			Cryo	Operated
		Area Total	240.0	183.2	23.4		
SouthTX							
Silver Oak I	100.0	Tuleta, TX	200.0			Cryo	Operated
Silver Oak II	90.0	Tuleta, TX	200.0			Cryo	Operated
		Area Total	400.0	120.0	13.8		
North Texas							
Chico (9)	100.0	Wise, TX	265.0			Cryo	Operated
Shackelford	100.0	Shackelford, TX	13.0			Cryo	Operated
Longhorn	100.0	Wise, TX	200.0			Cryo	Operated
		Area Total	478.0	347.6	39.6		
SouthOK (10)							
Atoka plant (11)	60.0	Atoka County, OK	20.0			Cryo	Operated
Coalgate plant	60.0	Coalgate, OK	80.0			Cryo	Operated
Stonewall plant	60.0	Coalgate, OK	200.0			Cryo	Operated
Tupelo plant	100.0	Coalgate, OK	120.0			Cryo	Operated
Velma plant	100.0	Velma, OK	100.0			Cryo	Operated
Velma V-60 plant	100.0	Velma, OK	60.0			Cryo	Operated
		Area Total	580.0	401.5	28.1		
WestOK (10)							
Waynoka I plant	100.0	Waynoka, OK	200.0			Cryo	Operated
Waynoka II plant	100.0	Waynoka, OK	200.0			Cryo	Operated
Chaney Dell plant (12)	100.0	Ringwood, OK	30.0			RA	Operated
Chester plant	100.0	Seiling, OK	28.0			Cryo	Operated
		Area Total	458.0	471.7	23.8		
Badlands							
Little Missouri (13)	100.0	McKenzie, ND	90.0	49.2	6.8	(14)	Operated
	Segment System Total		3,435.0	2,344.2	223.6		
Badlands crude oil gathered for 2015 was 106.3 MBbl/d.							

(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) Per day Gross Plant Natural Gas Inlet and NGL Production statistics for plants listed above are based on the number of days operational during 2015. The plants associated with the APL Merger are ten months of input based on 365 days. The Conger plant was idled due to market conditions in September 2014.

(4) Cryo – Cryogenic; RA – Refrigerated Absorption Processing.

(5) 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.

(6) The Benedum plant was idled in September 2014 after the start-up of the Edward plant.

(7) Plant natural gas inlet and NGL production volumes represent 100% of ownership interests for our consolidated Versado joint venture.

(8) Includes throughput other than plant inlet, primarily from compressor stations.
(9) The Chico plant has fractionation capacity of approximately 15 MBbl/d.
(10) Certain processing facilities in these business units are capable of processing more than their name-plate 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.
(11) The Atoka plant was idled due to the start-up of the of the Stonewall Plant in May 2014.
(12) The Chaney Dell plant was temporarily idled in December 2015 due to lower volumes in the WestOK system.

(13) Additional residue compression was added in 2014, bringing the nominal gas plant throughput capacity to 50 MMcf/d. An additional 40 MMcf/d expansion was added in January 2015, bringing the nominal capacity to 90 MMcf/d.
(14) Little Missouri I and II are Straight Refrigeration plants and Little Missouri III is a Cryo plant

Coastal Gathering and Processing Segment

Our Coastal Gathering and Processing segment assets are located in the onshore region of the Louisiana Gulf Coast, accessing natural gas from the Gulf Coast and the Gulf of Mexico. With the strategic location of our assets in Louisiana, we have access to the Henry Hub, the largest natural gas hub in the U.S., and to a substantial NGL distribution system with access to markets throughout Louisiana and the southeast U.S. The Coastal Gathering and Processing segment's assets consist of LOU and the Coastal Straddles, each as described below. For the year ended 2015, we processed an average of 897.0 MMcf/d of plant natural gas inlet and produced an average of 41.8 MBbl/d of NGLs.

LOU

LOU consists of approximately 900 miles of onshore gathering system pipelines in Southwest Louisiana. The gathering system is connected to numerous producing wells, central delivery points and/or pipeline interconnects in the area between Lafayette and Lake Charles, Louisiana. The gathering system is a high-pressure gathering system that delivers natural gas for processing to either the Acadia or Gillis plants via three main trunk lines. The processing facilities include the Gillis and Acadia processing plants, both of which are cryogenic plants. The Big Lake plant, also cryogenic, is located near the LOU gathering system. These processing plants have an aggregate processing capacity of approximately 440 MMcf/d. In addition, the Gillis plant has integrated fractionation with operating capacity of approximately 11 MBbl/d which is interconnected with the Lake Charles Fractionator. The LOU gathering system is also interconnected with the Lowry gas plant, allowing receipt or delivery of gas.

Coastal Straddles

Coastal Straddles process natural gas produced from shallow-water central and western Gulf of Mexico natural gas wells and from deep shelf and deep-water Gulf of Mexico production via connections to third-party pipelines or through pipelines owned by us. Coastal Straddles has 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 Gulf Coast by moving gas from older, less efficient plants to higher efficiency cryogenic plants. For example, in the last two years, the Yscloskey, Stingray and Calumet plants have been shut-down, with most of the producer volumes going to more efficient Targa plants such as our Venice, Lowry and Barracuda plants.

VESCO

Through our 76.8% ownership interest in Venice Energy Services Company, L.L.C., we operate the Venice gas plant, which has an aggregate processing capacity of 750 MMcf/d and the Venice Gathering System ("VGS") that is approximately 150 miles in length and has a nominal capacity of 320 MMcf/d (collectively "VESCO"). VESCO receives unprocessed gas directly or indirectly from seven offshore pipelines and gas gathering systems including the VGS system. VGS gathers natural gas from the shallow waters of the eastern Gulf of Mexico and supplies the VESCO gas plant.

Other Coastal Straddles

Other Coastal Straddles consists of two wholly owned and operated gas processing plants (one now idled) and three partially owned plants which are not operated by us. These plants, having an aggregate processing capacity of approximately 3,255 MMcf/d, are generally situated on mainline natural gas pipelines near the coastline and process volumes of natural gas collected from multiple offshore gathering systems and pipelines throughout the Gulf of Mexico. Coastal Straddles also has ownership in two offshore gathering systems that are operated by us. The Pelican and Seahawk gathering systems have a combined length of approximately 200 miles and a combined capacity of approximately 230 MMcf/d. These systems gather natural gas from the shallow waters of the central Gulf of Mexico and supply a portion of the natural gas delivered to the Barracuda and Lowry processing facilities.

The following table lists the Coastal Gathering and Processing segment's natural gas processing plants and related volumes for the year ended December 31, 2015:

Facility	% Owned	Location	Estimated Gross Processing Capacity (MMcf/d) (1)	Plant Natural Gas Inlet Throughput Volume (MMcf/d) (2) (3) (4)	NGL Production (MBbl/d) (3) (4)	Process Type (5)	
LOU							
Gillis (6)	100.0	Calcasieu, LA	180.0			Cryo	Operated
Acadia (7)	100.0	Acadia, LA	80.0			Cryo	Operated
Big Lake	100.0	Calcasieu, LA	180.0			Cryo	Operated
		Area Total	440.0	200.1	7.2		
VESCO (8)	76.8	Plaquemines, LA	750.0	442.4	26.6	Cryo	Operated
Coastal Straddles (9)							
Barracuda	100.0%	Cameron, LA	190.0			Cryo	Operated
Lowry (10)	100.0%	Cameron, LA	265.0			Cryo	Operated
Terrebone	11.1%	Terrebone, LA	950.0			RA	Non-operated
Toca	4.0%	St. Bernard, LA	1,150.0			Cryo/RA	Non-operated
Sea Robin	1.0%	Vermillion, LA	700.0			Cryo	Non-operated
		Area Total	3,255.0	254.5	8.0		
	Consolidated System Total		4,445.0	897.0	41.8		

(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.
(3) Plant natural gas inlet and NGL production volumes represent 100% of ownership interests for our consolidated VESCO joint venture and our ownership share of volumes for other partially owned plants which we proportionately consolidate based on our ownership interest which is 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 certain plants listed above are based on the number of days operational during 2015. The Big Lake facility was idled in November 2014 due to narrow processing spreads, restated in September 2015 and idled again in December 2015, but is available and operates on the LOU system as market conditions allow.
(5) Cryo – Cryogenic Processing; RA – Refrigerated Absorption Processing.
(6) The Gillis plant has fractionation capacity of approximately 11 MBbl/d.
(7) The Acadia Plant is available and operates on the LOU system as market conditions allow.
(8) VESCO also includes an offshore gathering system with a combined length of approximately 150 miles.
(9) Coastal Straddles also includes three offshore gathering systems which have a combined length of approximately 300 miles.
(10) The Lowry facility was idled in June 2015, but is available as market conditions allow.

Logistics and Marketing Division

Our Logistics and Marketing Division is also referred to as the Downstream Business. It includes the activities necessary to convert mixed NGLs into NGL products and provide certain value-added services such as the fractionation, storage, terminaling, transportation, exporting, distribution and marketing of NGLs and NGL products; the storing and terminaling of refined petroleum products and crude oil; and certain natural gas supply and marketing activities in support of our other businesses. These products are delivered to end-users through pipelines, barges, ships, trucks and rail cars. End-users of NGL products include petrochemical, refining companies, export markets for propane and butane, and propane markets for heating, cooking or agricultural applications.

Logistics Assets Segment

The Logistics Assets segment uses its platform of integrated assets to receive, fractionate, store, treat, transport and deliver NGLs typically under fee-based arrangements. For NGLs to be used by refineries, petrochemical manufacturers, propane distributors, international export markets and other industrial end-users, they must be fractionated into their component products and delivered to various points throughout the U.S. Our logistics assets are generally connected to, and supplied in part by, our gathering and processing assets and are primarily located at Mont Belvieu and Galena Park near Houston, Texas and in Lake Charles, Louisiana. This segment also contains refined petroleum product and crude oil storage and terminaling facilities in Texas (the Channelview and Patriot Terminals; both on the Houston Ship Channel), Maryland (the Baltimore Terminal), and Washington (the Sound Terminal, located in Tacoma).

Fractionation

After being extracted in the field, mixed NGLs, sometimes referred to as "Y-grade" or "raw NGL mix," 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 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, GCF, also located at Mont Belvieu. We are subject to a consent decree with the Federal Trade Commission, issued December 12, 1996, that, among other things, prevents us from participating in commercial decisions regarding rates paid by third parties for fractionation services at GCF. This restriction on our activity at GCF will terminate on December 12, 2016. In addition to the three stand-alone facilities in the Logistics Assets segment, see the description of fractionation assets in the North Texas System and LOU in our Gathering and Processing division.

We expanded the fractionation capacity of our assets during the last three years with the following projects:

- *CBF Train 4.* In August 2013, we commissioned 100 MBbl/d of additional fractionation capacity, Train 4, at CBF, in Mont Belvieu, Texas, at a gross cost of approximately $385 million (our net cost was approximately $345 million). Train 4 is supported by long-term contracts that have certain guaranteed volume commitments or provisions for deficiency payments.

- *CBF Train 5.T*his expansion is currently under construction and will add 100 MBbl/d of fractionation capacity. We expect completion of Train 5 in mid-2016. The gross cost of Train 5 is expected to be approximately $340 million and will be supported by supply from Targa's Gas Processing Division and by long-term contracts with third parties.

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 North Texas, South Texas, the Permian Basin, 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.

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 30 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 Assets segment's fractionation and treating facilities:

Facility	% Owned	Gross Capacity (MBbl/d) (1)	Gross Throughput for 2015 (MBbl/d)
Operated Facilities:			
Lake Charles Fractionator (Lake Charles, LA)	100.0	55.0	23.1
Cedar Bayou Fractionator (Mont Belvieu, TX) (2)	88.0	393.0	319.2
Targa LSNG Hydrotreater (Mont Belvieu, TX)	100.0	30.0	
LSNG treating volumes			22.4
Benzene treating volumes			22.4
Non-operated Facilities:			
Gulf Coast Fractionators (Mont Belvieu, TX)	38.8	125.0	114.5

(1) Actual fractionation capacities may also vary due to the Y-grade composition of the gas being processed and does not contemplate ethane rejection.
(2) Gross capacity represents 100% of the volume. Capacity includes 40 MBbl/d of additional butane/gasoline fractionation capacity.

Storage, Terminaling and Petroleum Logistics

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. 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.

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.

Across the Logistics Assets segment, we own or operate a total of 39 storage wells at our facilities with a net storage capacity of approximately 64 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. In September 2013, we commissioned Phase I of our international export expansion project that includes our facilities at both Mont Belvieu and the Galena Park Marine Terminal near Houston, Texas. Phase I of the project expanded our export capability to approximately 3.5 to 4 MMBbl per month of propane and/or butane. Included in the Phase I expansion was the capability to export international grade low ethane propane. With the completion of Phase I, we also added capabilities to load VLGC vessels alongside the small and medium sized export vessels that we load for export. We completed Phase II of the international export expansion project in the third quarter of 2014, which added approximately 3 MMBbl per month of export capacity. We continue to experience demand growth for US-based NGLs (both propane and butane) for export into international markets.

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

The following table details the Logistics Assets NGL storage facilities at December 31, 2015:

Facility	% Owned	Location	Number of Permitted Wells	Gross Storage Capacity (MMBbl)
Hackberry Storage (Lake Charles)	100	Cameron, LA	12(1)	20.0
Mont Belvieu Storage	100	Chambers, TX	21(2)	46.5

(1) Five of 12 owned wells leased to Citgo Petroleum Corporation under long-term leases.
(2) Excludes five non-owned wells we operate on behalf of Chevron Phillips Chemical Company LLC ("CPC"). Includes the first of four new permitted wells, which became operational in June 2015. The second new well, which has been drilled and is in the process of being washed.

The following table details the Logistics Assets NGL and Petroleum Terminal Facilities for the year ended December 31, 2015:

Facility	% Owned	Location	Description	Throughput for 2015 (Million gallons)	Usable Storage Capacity (MMBbl)
Galena Park Terminal (1)	100	Harris, TX	NGL import/export terminal, chemicals	3,585.9	0.7
Mont Belvieu Terminal	100	Chambers, TX	Transport and storage terminal	17,039.2	41.7
Hackberry Terminal	100	Cameron, LA	Storage terminal	982.5	17.8
Channelview Terminal	100	Harris, TX	Refined products, crude - transport and storage terminal	249.0	0.6
Baltimore Terminal	100	Baltimore, MD	Refined products - transport and storage terminal	25.0	0.5
Sound Terminal	100	Pierce, WA	Refined products, crude oil/propane - transport and storage terminal	460.0	1.4
Patriot	100	Harris, TX	Dock and land for expansion (Not in service)	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.

Marketing and Distribution Segment

The Marketing and Distribution segment 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 and Washington. The geographic diversity of our assets provide 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. The Marketing and Distribution segment consists of (i) NGL Distribution and Marketing, (ii) Wholesale Domestic Marketing, (iii) Refinery Services, (iv) Commercial Transportation, (v) Natural Gas Marketing and (vi) Terminal Facilities, each as described below.

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 segment, including exports. During the year ended December 31, 2015, our distribution and marketing services business sold an average of approximately 432.3 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 Assets 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 Assets 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 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, 2015, include approximately 700 railcars that we lease and manage, approximately 80 owned and leased transport tractors and 20 company-owned pressurized NGL barges.

Natural Gas Marketing

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

The following table details the Marketing and Distribution segment's Terminal Facilities:

Facility	% Owned	Location	Description	Throughput for 2015 (Million gallons) (1)	Usable Storage Capacity (Million gallons)
Calvert City Terminal	100	Marshall, KY	Propane terminal	9.9	0.1
Greenville Terminal	100	Washington, MS	Marine propane terminal	19.9	1.5
Port Everglades Terminal	100	Broward, FL	Marine propane terminal	7.2	1.6
Tyler Terminal	100	Smith, TX	Propane terminal	7.5	0.2
Abilene Transport (2)	100	Taylor, TX	Raw NGL transport terminal	-	0.1
Bridgeport Transport (2)	100	Jack, TX	Raw NGL transport terminal	-	0.1
Gladewater Transport (2)	100	Gregg, TX	Raw NGL transport terminal	-	0.3
Chattanooga Terminal	100	Hamilton, TN	Propane terminal	10.2	0.9
Sparta Terminal	100	Sparta, NJ	Propane terminal	14.0	0.2
Hattiesburg Terminal (3)	50	Forrest, MS	Propane terminal	363.1	302.0
Winona Terminal	100	Flagstaff, AZ	Propane terminal	16.0	0.3
Sound Terminal (4)	100	Pierce, WA	Propane terminal	6.0	0.2
Eagle Lake Transload (5)	100	Polk, FL	Propane terminal	5.8	-

(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) Included in the Logistics Assets segment.
(5) Rail-to-truck transload equipment.

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. Targa maintains, on behalf of us and our subsidiaries, general public liability, property, boiler and machinery and business interruption insurance in amounts that we consider to be appropriate for such risks. Such insurance is subject to deductibles that we consider reasonable and not excessive given the current insurance market environment. For example, following Hurricanes Katrina and Rita in 2005, 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 in September 2008. 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.

The occurrence of a significant loss that is not 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 Kinder Morgan, WTG Gas Processing, L.P. ("WTG"), DCP, Devon Energy Corporation ("Devon"), Enbridge Inc., Enlink Midstream Partners LP, Energy Transfer Partners, L.P., ONEOK, Gulf South Pipeline Company, LP, Hanlon Gas Processing, Ltd., J-W Operating Company, Louisiana Intrastate Gas Company L.L.C. and several other interstate pipeline companies. Our competitors for crude oil gathering services in North Dakota include Crestwood Equity Partners LP, Kinder Morgan, Great Northern Midstream LLC, Caliber Midstream Partners, L.P. and Bridger Pipeline LLC. Our competitors may have greater financial resources than we possess.

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

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 EPP, 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 competitor in providing export services to our customers is EPD.

Regulation of Operations

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

Regulation of Interstate Natural Gas Pipelines

VGS is regulated by FERC under the Natural Gas Act of 1938 (“NGA”), and the Natural Gas Policy Act of 1978 (“NGPA”). VGS operates under a FERC-approved, open-access tariff that establishes the rates and the terms and conditions under which the system provides services to its customers. Pursuant to FERC’s jurisdiction, existing pipeline rates and/or terms and conditions of service may be challenged by customer complaint or by FERC and proposed rate changes or changes in the terms and conditions of service may be challenged by protest. Generally, FERC’s authority extends to: transportation of natural gas; rates and charges for natural gas transportation; certification and construction of new facilities; extension or abandonment of services and facilities; maintenance of accounts and records; commercial relationships and communications between pipelines and certain affiliates; terms and conditions of service and service contracts with customers; depreciation and amortization policies; and acquisition and disposition of facilities.

VGS holds a certificate of public convenience and necessity issued by FERC permitting the construction, ownership, and operation of its interstate natural gas pipeline facilities and the provision of transportation services. This certificate authorization requires VGS to provide on a nondiscriminatory basis open-access services to all customers who qualify under its FERC gas tariff. FERC has the power to prescribe the accounting treatment of items for regulatory purposes. Thus, the books and records of VGS may be periodically audited by FERC.

The maximum recourse rates that may be charged by VGS for its services are established through FERC’s ratemaking process. Generally, the maximum filed recourse rates for interstate pipelines are based on the cost of service, including recovery of and a return on the pipeline’s investment. Key determinants in the ratemaking process are costs of providing service, allowed rate of return and volume throughput and contractual capacity commitment assumptions. VGS is permitted to discount its firm and interruptible rates without further FERC authorization down to the variable cost of performing service, provided they do not “unduly discriminate.” The applicable recourse rates and terms and conditions for service are set forth in each pipeline’s FERC-approved tariff. Rate design and the allocation of costs also can impact a pipeline’s profitability. On August 31, 2015, VGS filed a revised tariff sheet with FERC, seeking to increase the rates for service on VGS. Several of VGS’s customers protested the proposed increase, and the ratemaking proceeding remains pending. A hearing before a FERC administrative law judge on the proposed increase is schedule to begin on July 20, 2016.

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

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 NGPA and therefore are 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. TPL SouthTex Transmission is required to file, on or before November 6, 2017, a petition for approval of its then-existing rates, or to propose a new rate, applicable to NGPA Section 311 service.

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. FERC's treatment of the "stub" line exemption has varied over time, but, absent other factors, FERC generally limits the length of the lines that qualify for the "stub" line exemption. To the extent our plant tailgate pipelines do not qualify for the "stub" line exemption, we will consider whether we need to obtain FERC authorization to operate our tailgate pipelines or whether they can be reconfigured or otherwise modified to eliminate the possibility that they could be subject to FERC jurisdiction. If we conclude that FERC authorization is necessary, we would expect to seek regulatory treatment similar to the treatment FERC has accorded to the Driver Residue Pipeline. We cannot, however, be assured that FERC would agree to assert only limited jurisdiction. If FERC were to find that it must assert comprehensive jurisdiction, our operating costs would increase and we could be subject to enforcement actions under the Domenici-Barton Energy Policy Act of 2005 ("EP Act of 2005").

Texas, Louisiana, Oklahoma, and Kansas 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 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. These pipelines are not subject to FERC regulation or rate regulation by the DNR, but are regulated by United States Department of Transportation ("DOT") safety regulations.

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 Bureau of Land Management, 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 and NGLs

The price at which we buy and sell natural gas and NGLs is currently not subject to federal rate regulation and, for the most part, is not subject to state 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 were 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. 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 non-discriminatory. All shippers on these pipelines are our subsidiaries.

The crude oil pipeline system that is part of the Badlands assets has qualified for a temporary waiver of applicable FERC regulatory requirements under the ICA based on current circumstances. Such waivers are subject to revocation, however, should the 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 this pipeline system is within its jurisdiction. In the event that FERC were to determine that this pipeline system no longer qualified for waiver, we would likely be required to file a tariff with FERC, 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 this pipeline 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, including VGS. 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 stringent 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 capital costs to construct, maintain and upgrade equipment and facilities. We have implemented programs and policies designed to keep our pipelines, plants and other facilities in compliance with existing environmental laws and regulations. The recent trend in environmental regulation is to place more restrictions and limitations on activities that may 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. 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 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 for personal injury and property damage allegedly caused by the release of hazardous substances or other pollutants 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 such 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 strict 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 such as paint wastes, waste solvents and waste compressor oils 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, it is possible that future changes in law or regulation could result in these wastes, including wastes currently generated during our operations, being designated as "hazardous wastes" and therefore subject to more rigorous and costly disposal requirements. Any such changes in the laws and regulations could have a material adverse effect on our capital expenditures and operating expenses.

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 and NGL 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.

Air Emissions

The federal Clean Air Act 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 October 2015, the EPA issued a final rule under the Clean Air Act, lowering the National Ambient Air Quality Standard ("NAAQS") for ground-level ozone to 70 parts per billion under both the primary and secondary standards to provide requisite protection of public health and welfare, respectively. The final rule became effective on December 28, 2015, and EPA is expected to make final geographical attainment designations by late 2017. Such reclassification may make it more difficult to construct new or modified sources of air pollution in newly designated non-attainment areas. Also, states are expected to implement more stringent regulations, which could apply to our operations. Additionally, on August 18, 2015, the EPA proposed four new rules related to air emissions from the oil and gas industry, including (1) New Source Performance Standards for emissions of methane and VOCs from new and modified oil and natural gas production and natural gas gathering, processing, and transmission facilities; (2) suggested control technique guidelines for existing oil and gas sources for states to consider adopting in certain ozone non-attainment areas; (3) a rule intended to more clearly define, and possibly expand, the definition of a "source" for purposes of determining applicability of air emissions permitting for oil and gas sources; and (4) a Federal Implementation Plan to govern minor new source review air emissions permitting for oil and gas sources on certain Indian Reservations, including the Forth 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 Clean Air Act related to GHG emissions. See Risk Factor “The adoption 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 May 2015, the EPA released a final rule that attempted to clarify the meaning of the definition of “waters of the United States” under the CWA but several judicial challenges to this rule have been initiated, with plaintiffs’ generally objecting to the perceived broadening of the definition of waters of the United States under a rule that allegedly did not comply with appropriate procedural requirements. On August 27, 2015, one day prior to the rule going into effect, a federal district judge in North Dakota enjoined implementation of the rule in 13 states, and, on October 9, 2015 the Sixth Circuit Court of Appeals stayed the rule nationwide, as there are currently cases in more than a dozen district courts as well as the Sixth Circuit that may affect the rule and its implementation. Any expansion to CWA jurisdiction in areas where we or our customers operate could impose additional permitting obligations on us or our customers.

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 have asserted regulatory authority over aspects of the process, including the EPA and the federal Bureau of Land Management ("BLM"). In addition, Congress has from time to time considered the adoption of legislation to federally regulate hydraulic fracturing. At the state level, a growing number of states have adopted or are considering adopting legal requirements that could impose more stringent permitting, disclosure or well construction requirements on hydraulic fracturing activities, and states could elect to prohibit hydraulic fracturing altogether. In addition, local governments may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. Further, several federal governmental agencies are conducting reviews and studies on the environmental aspects of hydraulic fracturing activities, including the White House Council on Environmental Quality and the EPA which released a draft report for public and Scientific Advisory Board review in June 2015. These studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing. 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 wish to conduct development activities, such work could be prohibited or delayed or expensive mitigation may be required. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service ("FWS") is required to make a determination on the listing of numerous species as endangered or threatened under the ESA before the completion of the agency's 2017 fiscal year. The designation of previously unprotected species as threatened or endangered in areas where we or our oil and natural gas exploration and production 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 midstream services.

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 ("OSHA") 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 OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the Federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We and the entities in which we own an interest are 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 an internal program of inspection designed to monitor and enforce compliance with worker safety requirements.

Pipeline Safety

Many of our natural gas, NGL and crude pipelines are subject to regulation by the Pipeline and Hazardous Materials Safety Administration (“PHMSA”) of the DOT (or state analogs) under the Natural Gas Pipeline Safety Act of 1968 (“NGPSA”) with respect to natural gas, and the Hazardous Liquids Pipeline Safety Act of 1979 (“HLPSA”) with respect to crude oil, NGLs and condensates. Both the NGPSA and the HLPSA were amended by the Pipeline Safety Improvement Act of 2002 (“PSI Act”) and the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 (“PIPES Act”). 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 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. Our past compliance with the NGPSA and HLPSA has not had a material adverse effect on our results of operations; however, future compliance with these pipeline safety laws could result in increased costs.

These pipeline safety laws were amended by the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (“2011 Pipeline Safety Act”), which requires increased safety measures for gas and hazardous liquids transportation pipelines. Among other things, the 2011 Pipeline Safety Act directs the Secretary of Transportation to promulgate regulations relating to 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 2011 Pipeline Safety Act also increases the maximum penalty for violation of pipeline safety regulations from $100,000 to $200,000 per violation per day of violation and also from $1 million to $2 million for a related series of violations. The safety enhancement requirements and other provisions of the 2011 Pipeline Safety Act as well as any implementation of PHMSA regulations thereunder or any issuance or reinterpretation of PHMSA guidance 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 of which 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 and NGLs. North Dakota has similarly implemented regulatory programs applicable to intrastate natural gas pipelines. We currently estimate an annual average cost of $5.0 million for the years 2016 through 2018 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 expect that any such costs would be material to our financial condition or results of operations.

We, or the entities in which we own an interest, inspect our pipelines regularly in compliance with state and federal maintenance requirements. Nonetheless, the adoption of new or amended regulations by PHMSA or the states that result in more stringent or costly pipeline integrity management or safety standards could have a significant adverse effect on us and similarly situated midstream operators. For example, federal construction, maintenance and inspection standards that apply to pipelines in relatively populated areas generally do not apply to gathering lines running through rural regions. In recent years, the PHSMA has considered changes to this “rural gathering exemption, including publishing an advance notice of proposed rulemaking in 2011, in which the agency sought public comment on possible changes to the definition of “high consequence areas” and “gathering lines” and the strengthening of pipeline integrity management requirements. More recently, in response to an August 2014 report from the U.S. Government Accountability Office, the PHMSA stated that it is developing revisions to its pipeline safety regulations, including consideration of the need to adopt safety requirements for gas gathering pipelines that are not currently subject to regulation. In the absence of the PHMSA pursuing any legal requirements, state agencies, to the extent authorized, may pursue state standards, including standards for rural gathering lines. For example, in 2013 the Texas Legislature authorized the Texas Railroad Commission to adopt and implement safety standards applicable to the intrastate transportation of hazardous liquids and natural gas in rural locations by gathering pipeline. See Risk Factor “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 the Partnership 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.

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 is 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, right-of-way, permit, lease or license; and we believe that we have satisfactory title to all of our material leases, easements, rights-of-way, permits, leases and licenses.

Employees

We do not have any employees. To carry out our operations, Targa employs approximately 1,870 people who support primarily our operations. None of those employees are covered by collective bargaining agreements. Targa considers its employee relations to be good.

Financial Information by Reportable Segment

See "Segment Information" included under Note 23 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 Securities and Exchange Commission ("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.

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

Risks Related to Our Business

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, 2015, we had $4,832.9 million outstanding under our senior unsecured notes and $67.5 million of outstanding APL Notes, excluding $16.4 million of net unamortized discounts and premiums. We also had $219.3 million outstanding under our accounts receivable securitization facility (the "Securitization Facility"). In addition, we had $280.0 million of borrowings outstanding, $12.9 million of letters of credit outstanding and $1,307.1 million of additional borrowing capacity available under the TRP Revolver. Our $1.6 billion TRP Revolver allows us to request increases in commitments up to an additional $300 million. For the years ended December 31, 2015, 2014 and 2013, our consolidated interest expense, net was $207.8 million, $143.8 million and $131.0 million, respectively.

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 our 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 debt is currently rated by Standard & Poor's Corporation ("S&P") and Moody's Investors Service, Inc. ("Moody's"). As of December 31, 2015, our senior debt was rated "BB+" by S&P, until February 4, 2016, when S&P announced that it lowered the rating to "BB-". As of December 31, 2016, our senior debt was rated "Ba2" by Moody's. Any future downgrades in our credit ratings could negatively impact our cost of capital, and a downgrade could also adversely affect our ability to effectively execute aspects of our strategy and to access capital in the public markets.

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

Increases in interest rates could adversely affect our business.

We have significant exposure to increases in interest rates. As of December 31, 2015, our total indebtedness was $5,399.7 million, excluding $16.4 million net of unamortized discounts and premiums, of which $4,900.4 million was at fixed interest rates and $499.3 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 $5.0 million. As a result of this amount of variable interest rate debt, our financial condition could be negatively affected by increases in interest rates.

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

We may be able to incur substantial additional indebtedness in the future. As of December 31, 2015, we had $219.3 million of borrowings outstanding under our Securitization Facility. In addition, we had $280.0 million of borrowings outstanding, $12.9 million of letters of credit outstanding and $1,307.1 million of additional borrowing capacity available under the TRP Revolver. We may be able to increase the borrowing capacity under the TRP Revolver by an additional $300 million if we request and are able to obtain commitments from lenders for such additional amounts. Although the TRP Revolver contains 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, the risks associated with our substantial leverage would increase.

The terms of the TRP Revolver and indentures may restrict our current and future operations, particularly our ability to respond to changes in business or to take certain actions.

The credit agreement governing the TRP Revolver, the agreements governing our Securitization Facility and the indentures governing our senior notes 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 preferred stock;
- pay distributions on our equity securities or our equity holders or redeem, repurchase or retire our equity securities or subordinated indebtedness;
- make investments and certain acquisitions;
- pay distributions to our equity holders;
- 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, other than loans under the TRP Revolver;
- enter into sale and lease-back transactions or take-or-pay contracts; and
- change business activities conducted by us.

In addition, the TRP Revolver requires 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 the TRP Revolver, the indentures, or the Securitization Facility, as applicable. 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. 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 substantially all of our assets as collateral under the TRP Revolver and the accounts receivables of Targa Receivables LLC under the Securitization Facility. If our indebtedness under the TRP Revolver, the indentures, or the Securitization Facility 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. The duration and magnitude of the recent decline in oil, gas and NGLs prices cannot be predicted. Our future cash flow may be materially adversely affected if we experience significant, prolonged price deterioration. The markets and prices for natural gas and NGLs depend upon factors beyond our control. These factors include 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; 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 years ended December 31, 2015 and 2014, our percent-of-proceeds arrangements accounted for approximately 60% and 51%, respectively, 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. Please see “Item 7A. Quantitative and Qualitative Disclosures About Market Risk.”

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.

At February 27, 2015, our goodwill balance totaled $707.0 million. We evaluate goodwill for impairment at least annually, as of November 30th, 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. This decrease in commodity prices has had, and is expected to continue to have, a negative impact on the demand for our services and our market capitalization. Based on the results of our November 30 evaluation, we have recorded a provisional goodwill impairment of $290.0 million during the year ended December 31, 2015 which is included in impairment expense in our Consolidated Statements of Operations for the year ended December 31, 2015 and reduced the carrying value of goodwill to $417.0 million as of December 31, 2015.

Should energy industry conditions further deteriorate, there is a possibility that goodwill or other intangibles 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 provisional goodwill impairments, see Note 4 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 the current depressed commodity price environment. The recent decline in natural gas, NGL and crude oil prices may adversely affect the business, financial condition, results of operations, 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 the recent decline in commodity prices, a reduction in borrowing bases under reserve-based credit facility 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, the decline in the share price of some of our public customers may place them in danger of becoming delisted from a public securities exchange, limiting their access to the public capital markets and further restricting their liquidity. Furthermore, some of our customers may be highly leveraged and subject to their own operating and regulatory risks, which increases the risk that they may default on their obligations to us. To the extent one or more of our key customers is in financial distress or commences bankruptcy proceedings, contracts with these customers may be subject to renegotiation or rejection under applicable provisions of the United States Bankruptcy Code. Financial problems experienced by our customers could result in the impairment of our assets, reduction of our operating cash flows and may also reduce or curtail their future use of our products and services, which could reduce our revenues. Any material nonpayment or nonperformance by our key customers or our derivative counterparties could reduce our ability to make distributions to our unitholders.

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

Our gathering systems are connected to crude oil and natural gas wells from which production will naturally decline over time, which means that our 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 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 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. Consequently, even if new natural gas or crude oil reserves are discovered in areas served by our assets, producers may choose not to develop those reserves. For example, current low prices for natural gas combined with relatively high levels of natural gas in storage could result in curtailment or shut-in of natural gas production. Reductions in exploration and production activity, competitor actions or shut-ins by producers in the areas in which we operate may prevent us from obtaining supplies of natural gas or crude oil to replace the natural decline in volumes from existing wells, which could result in reduced volumes through our facilities and reduced utilization of our gathering, treating, processing and fractionation assets.

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

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

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

- operating a significantly larger combined organization and adding new or expanded operations;
- difficulties in the assimilation of the assets and operations of the acquired businesses or growth projects, especially if the assets acquired are in a new business segment and/or geographic area;
- the risk that crude oil and natural gas reserves expected to support the acquired assets may not be of the anticipated magnitude or may not be developed as anticipated;
- the failure to realize expected volumes, revenues, profitability or growth;
- the failure to realize any expected synergies and cost savings;
- coordinating geographically disparate organizations, systems and facilities;
- the assumption of environmental and other unknown liabilities;
- limitations on rights to indemnity from the seller in an acquisition or the contractors and suppliers in growth projects;
- the failure to attain or maintain compliance with environmental and other governmental regulations;
- inaccurate assumptions about the overall costs of equity or debt;
- the diversion of management's and employees' attention from other business concerns; 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, its capitalization and results of operations may change significantly and you may not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in evaluating future acquisitions or growth projects.

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

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

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

The construction of additions or modifications to our existing systems and the construction of new midstream assets involve numerous regulatory, environmental, political and legal uncertainties beyond our control and may require the expenditure of significant amounts of capital. If we undertake these projects, they may not be completed on schedule or 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 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 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 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 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 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 demand for propane may also adversely affect the retailers with which we transact our wholesale propane marketing operations, exposing us to their inability to satisfy their contractual obligations to us.

If we fail to balance our purchases of natural gas and our sales of residue gas and NGLs, our exposure to commodity price risk will increase.

We may not be successful in balancing our purchases of natural gas and our sales of residue gas and NGLs. 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. 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. In addition, 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 the future. 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. Please see "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 and NGLs, 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 and NGLs 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 ours. 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 to 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.

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. Our loss of these rights, through our inability to renew right-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 the best interests of us 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 us partnering with different or additional parties.

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. For example, in 2005, Hurricanes Katrina and Rita damaged gathering systems, processing facilities, NGL fractionators and pipelines along the Gulf Coast, including certain of our facilities, and curtailed or suspended the operations of various energy companies with assets in the region. The Louisiana and Texas Gulf Coast was similarly impacted in September 2008 as a result of Hurricanes Gustav and Ike. 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.

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 by the PSI Act, the PIPES Act and the 2011 Pipeline Safety Act, PHMSA has established a series of rules requiring pipeline operators to develop and implement integrity management programs for certain 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 gas and hazardous liquids pipelines. We currently estimate an average annual cost of $5.0 million between 2016 and 2018 to implement pipeline integrity management program testing along certain segments of our 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 instance, in August 2011, PHMSA published an advance notice of proposed rulemaking in which the agency sought public comment on a number of changes to regulations governing the safety of gas transmission pipelines and gathering lines, including, for example, revisions to the definitions of "high consequence areas" and "gathering lines" and strengthening integrity management requirements as they apply to existing regulated operators and to currently exempt operators should certain exemptions be removed. Most recently, in an August 2014 GAO report to Congress, the GAO acknowledged PHMSA's continued assessment of the safety risks posed by gathering lines and recommended that PHMSA move forward with rulemaking to address larger-diameter, higher-pressure gathering lines, including subjecting such pipelines to emergency response planning requirements that currently do not apply.

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 to third parties 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.

We require a significant amount of cash to service our indebtedness. Our ability to generate cash depends on many factors beyond our control.

Our ability to make payments on and to refinance our indebtedness and to fund planned capital expenditures depends on our ability to generate cash in the future. This, to a certain extent, is subject to general economic, financial, competitive, legislative, regulatory and other factors that are beyond our control. We cannot assure you that we will generate sufficient cash flow from operations, that future borrowings will be available to us under the TRP Revolver, that we will be able to sell our accounts receivables or make borrowings under the Securitization Facility, or otherwise in an amount sufficient to enable us to pay our indebtedness or to fund our other liquidity needs. We may need to refinance all or a portion of our indebtedness at or before maturity. We cannot assure you that we will be able to refinance any of our indebtedness on commercially reasonable terms or at all.

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 stringent 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 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 trigger a variety of administrative, civil and criminal penalties or other sanctions, the imposition of remedial obligations and the issuance of orders enjoining or conditioning future operations. 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.

There is inherent risk of incurring environmental costs and liabilities in connection with our operations 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.

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 gas exploration and production operators in the completion of certain oil and gas wells whereby water, sand and chemicals are injected under pressure into subsurface formations to stimulate gas and, to a lesser extent, oil production. The process is typically regulated by state oil and gas commissions, but several federal agencies have asserted regulatory authority over and proposed or promulgated regulations governing certain aspects of the process, including the EPA and United States Bureau of Land Management (“BLM”). Further several federal governmental agencies are conducting reviews and studies on the environmental aspects of hydraulic fracturing activities, including the White House Council on Environmental Quality and the EPA. Such studies, depending on their findings, could spur additional regulatory initiatives. In addition, Congress has from time to time considered the adoption of legislation to provide for federal regulation of hydraulic fracturing. At the state level, a growing number of states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure or well construction requirements on hydraulic fracturing activities, and states could elect to prohibit hydraulic fracturing altogether, as the State of New York did in 2015. In addition, local governments may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. 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.

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 our interest in VGS, which is subject to extensive FERC regulation, and the Driver Residue Pipeline and TPL SouthTex Transmission pipeline, which are each subject to more limited FERC regulation, our 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 its 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. FERC’s treatment of the “stub” line exemption has varied over time, but, absent other factors, FERC generally limits the length of the lines that qualify for the “stub” line exemption. 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, the Partnership’s operating costs could increase and the Partnership could be subject to enforcement actions under the EP Act of 2005.

The crude oil pipeline system that is part of the Badlands assets has qualified for a temporary waiver of applicable FERC regulatory requirements under the ICA based on current circumstances. Such waivers are subject to revocation, however, and should the 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 this pipeline system is within its jurisdiction. In the event that FERC were to determine that this pipeline system no longer qualified for a waiver, we would likely be required to file a tariff with FERC, 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 this pipeline could adversely affect our results of operations.

Various federal agencies within the U.S. Department of the Interior, particularly the Bureau of Land Management, 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 our natural gas regulatory activities, including, for example, our 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 VGS and the Driver Residue Pipeline 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 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.

Based on determinations made by the EPA that 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, the EPA has adopted rules related to GHG emissions under the Clean Air Act. Among other things, those rules establish PSD construction and Title V operating permit reviews for GHG emissions from certain large stationary sources that are also potential major sources of criteria pollutant emissions. In addition, the EPA has 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 published a final rule that expanded the petroleum and natural gas system sources for which annual GHG emissions reporting is required to include, beginning for the 2016 reporting year, certain onshore gathering and boosting systems consisting primarily of gathering pipelines, compressors and process equipment used to perform natural gas compression, dehydration and acid gas removal. Moreover, the EPA proposed in August 2015 rules that will establish emissions standards for methane and volatile organic compounds ("VOCs") from new and modified oil and natural gas production and natural gas processing and transmission facilities as part of the Obama Administration's efforts to reduce methane emissions from the oil and natural gas sector by up to 45 percent from 2012 levels by 2025. The EPA is expected to finalize the rules in 2016. Furthermore, the EPA has passed a rule, known as the Clean Power Plan, to limit GHGs from power plants. Depending on the methods used to implement the rule, it could reduce demand for the oil and natural gas our customers produce. While Congress has from time to time considered adopting legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs. The adoption of any legislation or regulations that requires reporting of GHGs or otherwise restricts emissions of GHGs from our equipment and operations could require us to incur significant added costs to reduce emissions of GHGs or could adversely affect demand for the natural gas and NGLs we gather and process or fractionate. Moreover, if Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on operations and reduce demand for refined products, which could adversely affect the services we provide. Finally, some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate change that could have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events; if such effects were to occur, they could have an adverse effect on our or our customers' operations.

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 2011 Pipeline Safety Act is the most recent federal legislation to amend the NGPSA and HLPSA pipeline safety laws, requiring increased safety measures for gas and hazardous liquids pipelines. Among other things, the 2011 Pipeline Safety Act directs the Secretary of Transportation to promulgate regulations relating to 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 2011 Pipeline Safety Act also increases the maximum penalty for violation of pipeline safety regulations from $100,000 to $200,000 per violation per day and also from $1 million to $2 million for a related series of violations. The safety enhancement requirements and other provisions of the 2011 Pipeline Safety Act as well as any implementation of PHMSA regulations thereunder 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, on October 13, 2015, PHMSA proposed new more stringent regulations for hazardous liquid pipelines, including extending certain integrity management assessment and repair requirements to pipelines not currently subject to integrity management regulations and requiring that all pipelines have a means of detecting leaks. The public comment period for these proposed regulations ended on January 8, 2016, and PHMSA may finalize the proposed regulations in 2016. 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 enactment 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 requires the CFTC and the SEC to promulgate rules and regulations implementing the Dodd-Frank Act. Although the CFTC has finalized certain 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. 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. 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 proposed margin rules are not yet final, and therefore the impact of those provisions to us is uncertain at this time.

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 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. 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. All shippers on these pipelines are our subsidiaries.

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.

Risks Related to Our Structure

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Risks Related to the Preferred Units

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

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

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

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

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

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

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

Tax Risks to Holders of Preferred Units

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

A publicly traded partnership such as us may be treated as a corporation for federal income tax purposes unless it satisfies a “qualifying income” requirement. Based on our current operations we believe that we satisfy the qualifying income requirement and will be treated as a partnership. Failing to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity. We have not requested and do not plan to request a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state income tax at varying rates. Distributions to you would generally be taxed again as corporate distributions instead of as guaranteed payments for the use of capital, as described further below. Because a tax would be imposed upon us as a corporation, our cash available for distribution to you may be substantially reduced. Therefore, treatment of us as a corporation may result in a material reduction in the anticipated cash flow.

At the state level, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income and franchise taxes and other forms of taxation. For example, we are subject to the Texas franchise tax at a maximum effective rate of 0.75% of our gross income apportioned to Texas in the prior year. Imposition of any such tax on us by any other state will reduce the cash available for distribution to you.

The tax treatment of publicly traded partnerships or an investment in us 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 us, or an investment in us may be modified by administrative, legislative or judicial changes or differing interpretations at any time. For example, the Obama administration's budget proposal for fiscal year 2016 recommends that certain publicly traded partnerships earning income from activities related to fossil fuels be taxed as corporations beginning in 2021. 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. If successful, the Obama administration's proposal or other similar proposals could eliminate the qualifying income exception to the treatment of all publicly traded partnerships as corporations, upon which we rely for our treatment as a partnership for U.S. federal income tax purposes.

In addition, the IRS, on May 5, 2015, issued proposed regulations concerning which activities give rise to qualifying income within the meaning of Section 7704 of the Internal Revenue Code. We do not believe the proposed regulations affect our ability to qualify as a publicly traded partnership. However, finalized regulations could modify the amount of our gross income that we are able to treat as qualifying income for the purposes of the qualifying income requirement and modify or revoke existing rulings, including ours.

Any modification to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible for us to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Any such changes could negatively impact the value of an investment in us.

The tax treatment of distributions on our Preferred Units as guaranteed payments for the use of capital is uncertain.

The tax treatment of distributions on our Preferred Units is uncertain. We will treat the holders of Series A Preferred Units as partners for tax purposes and will treat distributions on the Preferred Units as guaranteed payments for the use of capital that will generally be taxable to the holders of Preferred Units as ordinary income. Although a holder of Preferred Units could recognize taxable income from the accrual of such a guaranteed payment even in the absence of a contemporaneous distribution, we anticipate accruing and making the guaranteed payment distributions on a monthly basis. Otherwise, the holders of Preferred Units are generally neither anticipated to share in our items of income, gain, loss or deduction, nor be allocated any share of our nonrecourse liabilities. If the Preferred Units were treated as indebtedness for tax purposes, rather than as guaranteed payments for the use of capital, distributions likely would be treated as payments of interest by us to the holders of Preferred Units.

You may be required to pay taxes on your share of our income even if you do not receive any cash distributions from us.

Our partners, including holders of Preferred Units, may receive allocations of taxable income that are different in amount than the cash we distribute. You are required to pay federal income taxes and, in some cases, state and local income taxes on your share of our taxable income, even if you receive no cash distributions from us. You may not receive cash distributions from us equal to your share of our taxable income or even equal to the actual tax liability that resulting from that income.

Tax gain or loss on the disposition of our common units could be more or less than expected.

A holder of Preferred Units will be required to recognize gain or loss on a sale of units equal to the difference between the holder's amount realized and tax basis in the units sold. The amount realized generally will equal the sum of the cash and the fair market value of other property such holder receives in exchange for such Preferred Units. Subject to general rules requiring a blended basis among multiple partnership interests, the tax basis of a Preferred Unit will generally be equal to the sum of the cash and the fair market value of other property paid by the holder to acquire such Preferred Unit. Gain or loss recognized by a holder on the sale or exchange of a Preferred Unit held for more than one year generally will be taxable as long-term capital gain or loss. Because holders of Preferred Units will not be allocated a share of our items of depreciation, depletion or amortization, it is not anticipated that such holders would be required to recharacterize any portion of their gain as ordinary income as a result of the recapture rules. However, if the amount realized on a sale of a holder's Preferred Units is less than its adjusted basis in the units, the holder may receive allocations of ordinary income and capital loss from the sale of the units during the taxable period of the sale.

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

Investment in the Preferred Units by tax-exempt investors, such as employee benefit plans and individual retirement accounts ("IRAs"), and non-U.S. persons raises issues unique to them. Although the issue is not free from doubt, we will treat distributions to non-U.S. holders of the Preferred Units as "effectively connected income" (which will subject holders to U.S. net income taxation and possibly the branch profits tax) that are subject to withholding taxes imposed at the highest effective tax rate applicable to such non-U.S. holders. If the amount of withholding exceeds the amount of U.S. federal income tax actually due, non-U.S. holders may be required to file U.S. federal income tax returns in order to seek a refund of such excess. The treatment of guaranteed payments for the use of capital to tax exempt investors is not certain and such payments may be treated as unrelated business taxable income, or UBTI, for federal income tax purposes. If you are a tax-exempt entity or a non-U.S. person, you should consult your tax advisor with respect to the consequences of owning our Preferred Units.

If the IRS contests the federal income tax positions we take, the market for our Preferred Units may be adversely affected and the cost of any contest will reduce our cash available for distribution to you.

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

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

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

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have terminated our partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. The TRC/TRP Merger caused a termination of our partnership for federal income tax purposes. Similarly, a transfer of all or a portion of TRC's indirect interest in us, along with transfers by Holders of Preferred Units, could result in future terminations of our partnership for federal income tax purposes. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest are counted only once. Our termination results in the closing of our taxable year for all partners, which generally results in us filing two tax returns (and our unitholders receiving two Schedules K-1) for one calendar year. We intend to request relief from the IRS to provide only a single Schedule K-1 to our partners any tax year in which a technical termination occurs.

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

In addition to federal income taxes, Holders of Preferred Units may be subject to return filing requirements and other taxes, including state, local and non-U.S. income taxes, unincorporated business taxes, and estate, inheritance or intangibles taxes that may be imposed by the various jurisdictions in which we conduct business or own property or in which the common unitholder is a resident. Moreover, we may also own property or do business in other states in the future that impose income or similar taxes on nonresident individuals. You may be subject to penalties for failure to comply with return filing requirements. It is your responsibility to file all U.S. federal, state and local tax returns.

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 1000 Louisiana Street, Suite 4300, Houston, Texas 77002 and our telephone number is 713-584-1000.

Item 3. Legal Proceedings.

Litigation related to TRC/TRP Merger

On December 16, 2015, two purported unitholders of TRP (the "State Court Plaintiffs") filed a putative class action and derivative lawsuit challenging the TRC/TRP Merger against TRC, TRP (as a nominal defendant), TRP GP, the members of the board of our general partner (the "TRP GP Board") and Merger Sub (collectively, the "State Court Defendants"). This lawsuit is styled *Leslie Blumberg et al. v. TRC Resources Corp., et al.*, Cause No. 2015-75481, in the District Court of Harris County, Texas, 234th Judicial District (the "State Court Lawsuit").

The State Court Plaintiffs allege several causes of action challenging the TRC/TRP Merger. Generally, the State Court Plaintiffs allege that (i) the members of the TRP GP Board breached express and/or implied duties under the TRP partnership agreement and (ii) TRC, our general partner, and Merger Sub aided and abetted in these alleged breaches of duties. The State Court Plaintiffs further allege, in general, that (a) the premium offered to TRP's unitholders was inadequate, (b) the TRC/TRP Merger did not include a collar to protect TRP unitholders from decreases in TRC's stock price, (c) the TRP GP Board agreed to contractual terms that allegedly may have dissuaded other potential acquirers from seeking to acquire TRP (including the "no-solicitation," "matching rights," and "termination fee" provisions), (d) the process leading up to the TRC/TRP Merger was unfair and (e) the TRP GP Board has conflicts of interest due to TRC's control of our general partner.

Based on these allegations, the State Court Plaintiffs sought to enjoin the State Court Defendants from proceeding with or consummating the TRC/TRP Merger unless and until the TRP GP Board adopted and implemented processes to obtain the best possible terms for TRP common unitholders. The State Court Plaintiffs now seek to have the TRC/TRP Merger rescinded. The date to answer or otherwise respond to the State Court Lawsuit is currently set for February 29, 2016.

On January 6 and 19, 2016, two additional purported unitholders of TRP (the “Federal Court Plaintiffs”) filed two putative class action lawsuits challenging the disclosures made in connection with the TRC/TRP Merger against TRP and the members of the TRP GP Board (the “Federal Court Defendants”). These lawsuits have been consolidated as *In re Targa Resources Partners, L.P. Securities Litigation*, Consolidated C.A. No. 4:16-cv-00041, in the United States District Court for the Southern District of Texas, Houston Division (the “Federal Court Lawsuits”).

The Federal Court Plaintiffs allege that (i) the Federal Court Defendants have violated Section 14(a) of the Exchange Act and Rule 14a-9 promulgated thereunder and (ii) the members of the TRP GP Board have violated Section 20(a) of the Exchange Act. The Federal Court Plaintiffs allege, in general, that the preliminary and definitive joint proxy statements/prospectuses filed in connection with the TRC/TRP Merger fail, among other things, to disclose allegedly material information concerning (i) the TRP GP Conflicts Committee’s financial advisor’s and TRC’s financial advisor’s analyses in connection with the TRC/TRP Merger, (ii) certain TRC and TRP projections, and (iii) the events leading up to the TRC/TRP Merger. The Federal Court Plaintiffs further allege, in general, that (a) the premium offered to TRP’s unitholders was inadequate, (b) the TRC/TRP Merger did not include a collar to protect TRP unitholders from decreases in TRC’s stock price, (c) the TRP GP Board agreed to contractual terms that allegedly may have dissuaded other potential acquirers from seeking to acquire TRP (including the “no-solicitation,” “matching rights,” and “termination fee” provisions), (d) the process leading up to the TRC/TRP Merger was unfair and (e) the TRP GP Board has conflicts of interest due to TRC’s control of our general partner.

Based on these allegations, the Federal Court Plaintiffs sought to enjoin the Federal Court Defendants from proceeding with or consummating the TRC/TRP Merger unless and until the Federal Court Defendants disclosed the allegedly omitted information summarized above. The Federal Court Plaintiffs now seek to have the TRC/TRP Merger rescinded. The Federal Court Plaintiffs also seek damages and attorneys’ fees.

One of the Federal Court Plaintiffs sought a Temporary Restraining Order (“TRO”) to prevent the Federal Court Defendants from proceeding with the TRC/TRP vote and/or merger. On January 29, 2016, this Plaintiff was denied his request for a TRO.

The date for the Federal Court Defendants to answer, move to dismiss, or otherwise respond to the Federal Court Lawsuits has not yet been set.

Neither the State Court Defendants nor the Federal Court Defendants (collectively, the “Defendants”) can predict the outcome of these or any other lawsuits that might be filed subsequent to the date of the filing of this report, nor can Defendants predict the amount of time and expense that will be required to resolve such litigation. Defendants believe these lawsuits are without merit and intend to defend vigorously against these lawsuits and any other actions challenging the TRC/TRP Merger.

Targa Litigation related to Atlas Mergers

On January 28, 2015, a public shareholder of TRC (the “TRC Plaintiff”) filed a putative class action and derivative lawsuit against TRC (as a nominal defendant), its directors at the time of the ATLS Merger (the “TRC Director Defendants”), and ATLS (together with TRC and the TRC Director Defendants, the “TRC Lawsuit Defendants”). This lawsuit was styled *Inspired Investors v. Joe Bob Perkins, et al.*, in the District Court of Harris County, Texas (the “TRC Lawsuit”).

The TRC Plaintiff alleged a variety of causes of action challenging the disclosures related to the ATLS Merger. Generally, the TRC Plaintiff alleged that the TRC Director Defendants breached their fiduciary duties. The TRC Plaintiff further alleged that the registration statement filed on January 22, 2015 failed to disclose allegedly material details concerning (i) Wells Fargo Securities, LLC’s and the TRC Director Defendants’ supposed conflicts of interest with respect to the ATLS Merger, (ii) TRC’s financial projections, (iii) the background of the ATLS Merger, and (iv) Wells Fargo Securities, LLC’s analysis of the ATLS Merger.

Based on these allegations, the TRC Plaintiff sought to enjoin the TRC Lawsuit Defendants from proceeding with or consummating the ATLS Merger unless and until TRC disclosed the allegedly material omitted details. The TRC Plaintiff also sought to have the ATLS Merger rescinded, recissory damages, and attorneys' fees.

On June 9, 2015, the Court dismissed the TRC Lawsuit with prejudice.

Atlas Unitholder Litigation

Between October and December 2014, five public unitholders of APL (the "APL Plaintiffs") filed putative class action lawsuits against APL, ATLS, APL GP, its managers, Targa, the Partnership, the general partner and MLP Merger Sub (the "APL Lawsuit Defendants"). These lawsuits were styled (a) *Michael Evnin v. Atlas Pipeline Partners, L.P., et al*., in the Court of Common Pleas for Allegheny County, Pennsylvania; (b) *William B. Federman Family Wealth Preservation Trust v. Atlas Pipeline Partners, L.P., et al.*, in the District Court of Tulsa County, Oklahoma (the "Tulsa Lawsuit"); (c) *Greenthal Living Trust U/A 01/26/88 v. Atlas Pipeline Partners, L.P., et al*., in the Court of Common Pleas for Allegheny County, Pennsylvania; (d) *Mike Welborn v. Atlas Pipeline Partners, L.P., et al.*, in the Court of Common Pleas for Allegheny County, Pennsylvania; and (e) *Irving Feldbaum v. Atlas Pipeline Partners, L.P., et al.*, in the Court of Common Pleas for Allegheny County, Pennsylvania, though the Tulsa Lawsuit has been voluntarily dismissed. The *Evnin*, *Greenthal*, *Welborn and Feldbaum* lawsuits have been consolidated as *In re Atlas Pipeline Partners, L.P. Unitholder Litigation*, Case No. GD-14-019245, in the Court of Common Pleas for Allegheny County, Pennsylvania (the "Consolidated APL Lawsuit"). In October and November 2014, two public unitholders of ATLS (the "ATLS Plaintiffs" and, together with the APL Plaintiffs, the "Atlas Lawsuit Plaintiffs") filed putative class action lawsuits against ATLS, ATLS GP, its managers, Targa and GP Merger Sub (the "ATLS Lawsuit Defendants" and, together with the APL Lawsuit Defendants, the "Atlas Lawsuit Defendants"). These lawsuits were styled (a) *Rick Kane v. Atlas Energy, L.P., et al.*, in the Court of Common Pleas for Allegheny County, Pennsylvania and (b) *Jeffrey Ayers v. Atlas Energy, L.P., et al.*, in the Court of Common Pleas for Allegheny County, Pennsylvania (the "ATLS Lawsuits"). The ATLS Lawsuits have been consolidated as *In re Atlas Energy, L.P. Unitholder Litigation*, Case No. GD-14-019658, in the Court of Common Pleas for Allegheny County, Pennsylvania (the "Consolidated ATLS Lawsuit" and, together with the Consolidated APL Lawsuit, the "Consolidated Atlas Lawsuits"), though the *Kane* lawsuit has been voluntarily dismissed.

The Atlas Lawsuit Plaintiffs alleged a variety of causes of action challenging the Atlas mergers. Generally, the APL Plaintiffs alleged that (a) APL GP's managers have breached the covenant of good faith and/or their fiduciary duties and (b) Targa, the Partnership, the general partner, MLP Merger Sub, APL, ATLS and APL GP have aided and abetted in these alleged breaches of the covenant of good faith and/or fiduciary duties. The APL Plaintiffs further alleged that (a) the premium offered to APL's unitholders was inadequate, (b) APL agreed to contractual terms that would allegedly dissuade other potential acquirers from seeking to acquire APL, and (c) APL GP's managers favored their self-interests over the interests of APL's unitholders. The APL Plaintiffs in the Consolidated APL Lawsuit also alleged that the registration statement filed on November 19, 2014 failed, among other things, to disclose allegedly material details concerning (i) Stifel, Nicolaus & Company, Incorporated's analysis of the Atlas mergers; (ii) APL and the Partnership's financial projections; and (iii) the background of the Atlas mergers. Generally, the ATLS Plaintiffs alleged that (a) ATLS GP's directors have breached the covenant of good faith and/or their fiduciary duties and (b) Targa, GP Merger Sub, and ATLS have aided and abetted in these alleged breaches of the covenant of good faith and/or fiduciary duties. The ATLS Plaintiffs further alleged that (a) the premium offered to the ATLS unitholders was inadequate, (b) ATLS agreed to contractual terms that would allegedly dissuade other potential acquirers from seeking to acquire ATLS, (c) ATLS GP's directors favored their self-interests over the interests of the ATLS unitholders and (d) the registration statement failed to disclose allegedly material details concerning, among other things, (i) Wells Fargo Securities, LLC, Stifel, Nicolaus & Company, Incorporated, and Deutsche Bank Securities Inc.'s analyses of the Atlas mergers; (ii) the Partnership, Targa, APL, and ATLS' financial projections; and (iii) the background of the Atlas mergers.

Based on these allegations, the Atlas Lawsuit Plaintiffs sought to enjoin the Atlas Lawsuit Defendants from proceeding with or consummating the Atlas mergers unless and until APL and ATLS adopted and implemented processes to obtain the best possible terms for their respective unitholders. The Atlas Lawsuit Plaintiffs also sought rescission, damages, and attorneys' fees.

The parties to the Consolidated Atlas Lawsuits agreed to settle the Consolidated Atlas Lawsuits on February 9, 2015. In general, the settlements provide that in consideration for the dismissal of the Consolidated Atlas Lawsuits, ATLS and APL would provide supplemental disclosures regarding the Atlas mergers in a filing with the SEC on Form 8-K, which ATLS and APL did on February 11, 2015. The Atlas Lawsuit Defendants agreed to make such supplemental disclosures solely to avoid the uncertainty, risk, burden, and expense inherent in litigation and deny that any supplemental disclosure was or is required under any applicable rule, statute, regulation or law. On January 21, 2016, the Court granted final approval of the settlements in the Consolidated Atlas Lawsuits and dismissed the Consolidated Atlas Lawsuits with prejudice.

Environmental Proceedings

On August 22, 2014 and September 9, 2014, the Texas Commission on Environmental Quality (“TCEQ”) issued Notices of Enforcement (“NOEs”) to Targa Midstream Services LLC for alleged violations of air emissions regulations at the Mont Belvieu Fractionator relating to the operations of two regenerative thermal oxidizers during 2013 and 2014 and an unrelated discrete emissions event that occurred on May 29, 2014. On May 26, 2015, we signed an Agreed Order resolving all alleged violations stated in the NOEs. The Executive Director of the TCEQ signed the Agreed Order on September 11, 2015, and the TCEQ Commissioners approved the Agreed Order during their November 4, 2015 meeting. Pursuant to the Agreed Order, we (1) paid an administrative penalty in the amount of $115,644; and (2) paid $115,643 to fund certain supplemental environmental projects. Under the Agreed Order, we must comply with certain ordering provisions, including a requirement to install a flare gas recovery unit at the Mont Belvieu Fractionator within one year of the effective date of the Agreed Order.

On June 18, 2015, the New Mexico Environment Department’s Air Quality Bureau issued a Notice of Violation to Targa Midstream Services LLC for alleged violations of air emissions regulations related to emissions events that occurred at the Monument Gas Plant between June 2014 and December 2014. The Monument Gas Plant is operated by us and owned by Versado Gas Processors, L.L.C., which is a joint venture in which we own a 63% interest. We are in discussions with the New Mexico Environment Department to resolve the alleged violations. We anticipate that this matter could result in a monetary sanction in excess of $100,000 but less than $300,000.

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

Item 4. Mine Safety Disclosures.

Not applicable.

PART II

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

Market Information

Our common units were listed on the NYSE under the symbol "NGLS" prior to the closing of the TRC/TRP Merger on February 17, 2016. As of February 17, 2016, there were 184,899,602 common units outstanding.

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

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

Quarter Ended	Unit Prices		Distribution per Common Unit
	High	Low	
December 31, 2015	$ 33.50	$ 13.07	$ 0.8250
September 30, 2015	41.76	23.50	0.8250
June 30, 2015	47.00	37.86	0.8250
March 31, 2015	50.40	37.33	0.8200
December 31, 2014	73.20	40.17	0.8100
September 30, 2014	74.51	63.87	0.7975
June 30, 2014	83.49	57.02	0.7800
March 31, 2014	56.94	49.66	0.7625
December 31, 2013	54.25	48.09	0.7475
September 30, 2013	54.13	47.57	0.7325
June 30, 2013	50.87	43.52	0.7150
March 31, 2013	46.25	37.59	0.6975

There is no established trading market for the 3,773,461 general partner units held only by our general partner.

Distributions of Available Cash

General

Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all of our available cash to unitholders of record on the applicable record date, as determined by our general partner. As a result of the TRC/TRP Merger, which was completed on February 17, 2016, Targa owns all of our outstanding common units. See Note 9 – Debt Obligations and Note 11 – Partnership Units and Related Matters of the "Consolidated Financial Statements" included in this Annual Report.

The following table details the distributions declared and/or paid on our common units, incentive distribution rights ("IDRs") and our general partner interest for the periods presented:

		Distributions				
		Limited Partners	General Partner			
Three Months Ended	Date Paid	Common	Incentive Distribution Rights	2%	Total	Distributions per Limited Partner Unit
		(In millions, except per unit amounts)				
2015						
December 31, 2015	February 9, 2016	$ 152.5	$ 43.9(1)	$ 4.0	$ 200.4	$ 0.8250
September 30, 2015	November 13, 2015	152.5	43.9(1)	4.0	200.4	0.8250
June 30, 2015	August 14, 2015	152.5	43.9(1)	4.0	200.4	0.8250
March 31, 2015	May 15, 2015	148.3	41.7(1)	3.9	193.9	0.8200
2014						
December 31, 2014	February 13, 2015	96.3	38.4	2.7	137.4	0.8100
September 30, 2014	November 14, 2014	92.3	36.0	2.6	130.9	0.7975
June 30, 2014	August 14, 2014	89.5	33.7	2.5	125.7	0.7800
March 31, 2014	May 15, 2014	87.2	31.7	2.4	121.3	0.7625
2013						
December 31, 2013	February 14, 2014	84.0	29.5	2.3	115.8	0.7475
September 30, 2013	November 14, 2013	79.4	26.9	2.2	108.5	0.7325
June 30, 2013	August 14, 2013	75.8	24.6	2.0	102.4	0.7150
March 31, 2013	May 15, 2013	71.7	22.1	1.9	95.7	0.6975

(1) Pursuant to the IDR Giveback Amendment in conjunction with the Atlas mergers, IDRs of $9.375 million were allocated to common unitholders in each of the quarters for 2015. The IDR Giveback Amendment covers sixteen quarterly distribution declarations following the completion of the Atlas mergers on February 27, 2015 and resulted in reallocation of IDR payments to common unitholders in the following amounts: $9.375 million per quarter for 2015. The IDR Giveback will result in reallocation of IDR payments to common unitholders of $6.25 million per quarter for 2016.

Definition of Available Cash

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

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

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

Preferred Units

Distributions on the Preferred Units are cumulative from the date of original issue and are payable monthly in arrears on the 15th day of each month of each year, when, as and if declared by the board of directors of our general partner. Distributions on the Preferred Units will be paid out of amounts legally available therefor to, but not including, November 1, 2020, at a rate equal to 9.0% per annum. On and after November 1, 2020, distributions on the Preferred Units will accumulate at an annual floating rate equal to the one-month LIBOR plus a spread of 7.71%. As of December 31, 2015, we have paid $1.5 million in distributions to the holders of our Preferred Units. See Notes 9 - Debt and 11 - Partnership Units and Related Matters of the “Consolidated Financial Statements” included in this Annual Report.

Recent Sales of Unregistered Securities

None.

Repurchase of Equity by Targa Resources Partners LP or Affiliated Purchasers

Period	Total number of units withheld (1)	Average price per share	Total number of units purchased as part of publicly announced plans	Maximum number of units that may yet be purchased under the plan
October 1, 2015 - October 31, 2015	185	31.26	-	-
November 1, 2015 - November 30, 2015	7,378	29.92	-	-
December 1, 2015 - December 31, 2015	3,448	17.36	-	-

(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 the equity-settled performance units.

Item 6. Selected Financial Data.

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

	2015	2014	2013	2012	2011
	(In millions, except per unit amounts)				
Statement of operations data:					
Revenues	$ 6,658.6	$ 8,616.5	$ 6,314.9	$ 5,676.9	$ 6,835.8
Income from operations	167.4	653.3	377.2	342.9	354.9
Net income (loss)	(59.3)	505.1	258.6	203.2	245.5
Net income (loss) attributable to Targa Resources Partners LP	(27.4)	467.7	233.5	174.6	204.5
Net income (loss) per limited partner unit - basic	(15)	2.78	1.19	1.20	1.98
Net income (loss) per limited partner unit - diluted	(15)	2.77	1.19	1.20	1.98
Balance sheet data (at end of period):					
Total assets	13,165.0	6,377.2	5,971.4	5,025.7	3,658.0
Long-term debt	5,164.0	2,783.4	2,905.3	2,393.3	1,477.7
Other:					
Distributions declared per unit	3.30	3.15	2.89	2.61	2.31

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 historical financial statements and notes included in Part IV of this Annual Report.

Overview

Targa Resources Partners LP is a Delaware limited partnership formed in October 2006 by TRC. Our common units were listed on the NYSE under the symbol "NGLS." Our Preferred Units are listed on the NYSE under the symbol "NGLS PRA."

Targa Resources GP LLC, our general partner, is a Delaware limited liability company formed by Targa in October 2006 to own a 2% general partner interest in us. Its primary business purpose is to manage our affairs and operations. Targa Resources GP LLC is an indirect wholly owned subsidiary of Targa.

Following the closing of the TRC/TRP Merger, TRC owns all of our outstanding common units.

Our Operations

We are a leading provider of midstream natural gas and NGL services in the United States, with a growing presence in crude oil gathering and petroleum terminaling. In connection with these business activities, we buy and sell natural gas, NGLs and NGL products, crude oil, condensate and refined products.

We are engaged in the business of:

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

We report our operations in two divisions: (i) Gathering and Processing, consisting of two reportable segments – (a) Field Gathering and Processing and (b) Coastal Gathering and Processing; and (ii) Logistics and Marketing consisting of two reportable segments – (a) Logistics Assets and (b) Marketing and Distribution. The operating margin results of our commodity derivative activities are reported in Other.

Our Gathering and Processing division 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 Field 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; and the Williston Basin in North Dakota. The Coastal Gathering and Processing segment's assets are located in the onshore and near offshore regions of the Louisiana Gulf Coast and the Gulf of Mexico.

Our Logistics and Marketing division is also referred to as our Downstream Business. Our Downstream Business includes all the activities necessary to convert mixed NGLs into NGL products and provides certain value-added services such as the fractionation, storage, terminaling, transportation, exporting, distribution and marketing of NGLs and NGL products; the storing and terminaling of refined petroleum products and crude oil; and certain natural gas supply and marketing activities in support of the Partnership's other businesses, as well as transporting natural gas and NGLs.

Our Logistics Assets segment is involved in transporting, storing, and fractionating mixed NGLs; storing, terminaling, and transporting finished NGLs, including services for exporting LPGs; and storing and terminaling of refined petroleum products. These assets are generally connected to and supplied in part by our Gathering and Processing segments and are predominantly located in Mont Belvieu and Galena Park, Texas, in Lake Charles, Louisiana and in Tacoma, Washington.

Our Marketing and Distribution segment covers activities required to distribute and market raw and finished NGLs and all natural gas marketing activities. It includes (1) marketing our own NGL production and purchasing NGL products for resale in selected United States markets; (2) providing LPG balancing services to refinery customers; (3) transporting, storing and selling propane and providing related propane logistics services to multi-state retailers, independent retailers and other end-users; (4) providing propane, butane and services to LPG exporters; and (5) marketing natural gas available to us from our Gathering and Processing division and the purchase and resale and other value added activities related to third-party natural gas in selected United States markets.

Other contains the results (including any hedge ineffectiveness) of our commodity derivative activities included in operating margin and the mark-to-market gains/losses related to derivative contracts that were not designated as cash-flow hedges.

TRC/TRP Merger

On February 17, 2016, TRC completed the previously announced transactions contemplated by the Merger Agreement, by and among us, our general partner, TRC and Merger Sub pursuant to which TRC acquired indirectly all of our outstanding common units that TRC and its subsidiaries did not already own. Upon the terms and conditions set forth in the Merger Agreement, Merger Sub merged with and into TRP, 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 TRC or its subsidiaries was converted into the right to receive 0.62 TRC shares. No fractional TRC shares were issued in the TRC/TRP Merger, and TRP common unitholders instead received cash in lieu of fractional TRC shares.

2015 Developments

Atlas Mergers

On February 27, 2015, Targa completed the Atlas mergers. 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, Ardmore, Arkoma and Permian Basins located in the southwestern and mid-continent regions of the United States and in the Eagle Ford Shale play in South Texas. The Atlas mergers add TPL’s Woodford SCOOP, Mississippi Lime, Eagle Ford and additional Permian assets to the Partnership’s existing operations. In total, TPL adds 2,053 MMcf/d of processing capacity and 12,220 miles of additional pipeline. The results of TPL are reported in our Field Gathering and Processing segment.

Pursuant to the IDR Giveback Amendment entered into in conjunction with the Atlas mergers, IDRs of $9.375 million were allocated to common unitholders for each quarter of 2015 commencing with the first quarter of 2015. The IDR Giveback Amendment covers sixteen quarters following the completion of the Atlas mergers on February 27, 2015 and resulted in reallocation of IDR payments to common unitholders –in the amount of $9.375 million per quarter for 2015, and will result in reallocation of IDR payments to common unitholders in the amount of $6.25 million in the first quarter of 2016.

Logistics and Marketing Segment Expansion

Cedar Bayou Fractionator Train 5

In July 2014, we approved construction of a 100 MBbl/d fractionator at CBF. The 100 MBbl/d expansion will be 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. Construction has been underway and is continuing and we expect completion of construction in second quarter of 2016. Construction of the expansion has proceeded without disruption to existing operations, and we estimate that total growth capital expenditures net to our 88% interest for the expansion and the related infrastructure enhancements at Mont Belvieu should approximate $340 million.

Channelview Splitter

On December 27, 2015, Targa Terminals and Noble entered into the Splitter Agreement under which Targa Terminals will build and operate a 35,000 barrel per day crude and condensate splitter at Targa Terminals' Channelview Terminal on the Houston Ship Channel ("Channelview Splitter"). The Channelview Splitter will have the capability to split approximately 35,000 barrels per day of 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 is expected to be completed by early 2018, and has an estimated total cost of approximately $130 million to $150 million. Our current total project capital expenditure estimate is higher than in the original announcement in March 2014 because of changes in project scope and anticipated increases in costs for engineering, procurement and construction services and/or materials, including labor costs. As contemplated by the December 2014 Agreement, the Splitter Agreement completes and terminates the December 2014 Agreement while retaining our economic benefits from that agreement.

Field Gathering and Processing Segment Expansion

Badlands Little Missouri 3

In the first quarter of 2015, we completed the 40 MMcf/d Little Missouri 3 plant expansion in McKenzie County, North Dakota, that increased capacity to 90 MMcf/d.

Permian Basin Buffalo Plant

In April 2014, TPL announced plans to build a new plant and expand the gathering footprint of its WestTX system. This project includes the laying of a new high pressure gathering line into Martin and Andrews counties of Texas, as well as incremental compression and a new 200 MMcf/d cryogenic processing plant, known as the Buffalo plant, which is now expected to be completed during the second quarter of 2016. Total net growth capital expenditures for the Buffalo plant should approximate $105 million.

Eagle Ford Shale Natural Gas Processing Joint Venture

In October 2015, we announced that we entered into joint venture agreements with Sanchez to construct the Raptor Plant and approximately 45 miles of associated pipelines. We own a 50% interest in the plant and the approximately 45 miles of high pressure gathering pipelines that will connect Sanchez's Catarina gathering system to the plant. We hold a portion of the transportation capacity on the pipeline and the gathering joint venture receives fees for transportation. We expect to invest approximately $125 million of growth capital expenditures related to the joint ventures.

The Raptor Plant will accommodate the 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 lines are supported by long-term, firm, fee-based contracts and acreage dedications with Sanchez. We will manage construction and operations of the plant and high pressure gathering lines, and the plant is expected to begin operations in early 2017. Prior to the plant being placed in-service, we will benefit from Sanchez natural gas volumes that will be processed at our Silver Oak facilities in Bee County, Texas.

In addition to the major projects in process noted above, we potentially have other growth capital expenditures in 2016 related to the continued build out of its gathering and processing infrastructure and logistics capabilities. In the current depressed commodity price environment, we will evaluate these potential projects based on return profile, capital requirements and strategic need and may choose to defer projects depending on expected activity levels.

Accounts Receivable Securitization Facility

The Securitization Facility provides up to $225.0 million of borrowing capacity at LIBOR market index rates plus a margin through December 9, 2016. Under the Securitization Facility, Targa Midstream Services LLC (“TMS”), our consolidated subsidiary, contributes receivables to Targa Gas Marketing LLC (“TGM”), our consolidated subsidiary, and TGM and another of our consolidated subsidiaries (Targa Liquids Marketing and Trade LLC (“TLMT”)) sell or contribute 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 a third-party financial institution. Receivables up to the amount of the outstanding debt under the Securitization Facility are not available to satisfy the claims of the creditors of TLMT, TMS, TGM or us. Any excess receivables are eligible to satisfy the claims of creditors of TLMT, TMS, TGM or us. As of December 31, 2015, total funding under the Securitization Facility was $219.3 million.

Distributions

During 2015, we paid cash distributions of $3.28 per unit, an increase of approximately six percent compared with the $3.09 per unit paid during 2014. In January 2016, our general partner declared a cash distribution of $0.825 per unit ($3.30 on an annualized basis) for the fourth quarter 2015, an increase of approximately two percent compared with the $ 0.81 per unit declared in January 2015.

Other Financing Activities

In January 2015, we issued $1.1 billion in aggregate principal amount of 5% Notes. The $1,089.8 million of net proceeds after costs were used together with borrowings from the TRP Revolver to fund the APL Notes Tender Offers and the Change of Control Offer.

In February 2015, we amended our TRP Revolver to increase available commitments to $1.6 billion from $1.2 billion while retaining the right to request up to an additional $300.0 million in commitment increases. We used proceeds from borrowings under our credit facility 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. In connection with the 58,614,157 common units issued in the Atlas mergers in February 2015, Targa contributed an additional $52.4 million to us to maintain its 2% general partner interest.

In May 2015, we entered into the May 2015 EDA, pursuant to which we may sell through our sales agents, at our option, up to an aggregate of $1.0 billion of our common units. During the twelve months ended December 31, 2015, we issued 7,377,380 total common units receiving proceeds of $316.1 million (net of commissions). As of December 31, 2015, approximately $4.2 million of capacity and $835.6 million of capacity remain under the May 2014 and May 2015 EDAs. During the twelve months ended December 31, 2015, Targa contributed $6.5 million to us to maintain its 2% general partner interest. Pursuant to the TRC/TRP Merger Agreement, TRC has agreed to cause our 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, our common units are no longer publicly traded.

In May 2015, we issued $342.1 million aggregate principal amount of the TRP 6⅝% Notes to holders of the 2020 APL Notes, which were validly tendered for exchange.

In September 2015, we issued $600.0 million in aggregate principal amount of 6¾% Notes resulting 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.

In October 2015, we completed an offering of 4,400,000 9.00% Preferred Units at a price of $25.00 per unit. We sold an additional 600,000 Preferred Units pursuant to the exercise of the underwriters’ overallotment option. We received net proceeds after costs of approximately $121.1 million. We used the net proceeds from this offering to reduce borrowings under the TRP Revolver and for general partnership purposes. As of December 31, 2015, we have paid $1.5 million in distributions to our preferred unitholders. See Note 11 - Partnership Units and Related Matters. The Preferred Units remain outstanding as limited partner interests in TRP and continue to trade on the NYSE under the symbol “NGLS PRA.”

In December 2015, we repurchased on the open market a portion of various series of outstanding senior notes paying $14.3 million plus accrued interest to repurchase $17.9 million of the outstanding balances. The December 2015 Senior Note Repurchases resulted in a $3.6 million gain on debt repurchase and a write-off of $0.1 million in related deferred debt issuance costs.

APL Merger Financing Activities

APL Senior Notes Tender Offers

In January 2015, we commenced cash tender offers for any and all of the outstanding fixed rate senior secured notes to be acquired in the APL merger, referred to as the APL Notes Tender Offers, which totaled $1.55 billion.

The results of the APL Notes Tender Offers were:

Senior Notes	Outstanding Note Balance	Amount Tendered	Premium Paid	Accrued Interest Paid	Total Tender Offer payments	% Tendered	Note Balance after Tender Offers
			($ amounts in millions)				
6⅝% due 2020	$ 500.0	$ 140.1	$ 2.1	$ 3.7	$ 145.9	28.02%	$ 359.9
4¾% due 2021	400.0	393.5	5.9	5.3	404.7	98.38%	6.5
5⅞% due 2023	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 APL Notes Tender Offers, on February 27, 2015, the supplemental indentures governing the 4¾% Senior Notes due 2021 (the “2021 APL Notes”) and the 5⅞% Senior Notes due 2023 (the “2023 APL 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 APL Notes and the 2023 APL Notes that were not accepted for payment.

Not having achieved the minimum tender condition on the 6⅝% Senior Notes due 2020 of the APL Issuers (the “2020 APL Notes”), we made a change of control offer, referred to as the Change of Control Offer, for any and all of the 2020 APL 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 APL 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 APL Notes Tender Offers and Change of Control Offer totaling $1,168.8 million are presented as financing activities in the Consolidated Statements of Cash Flows.

Recent Accounting Pronouncements

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 identifying the contracts with customers, identifying the performance obligations in the contracts, determining the transaction price, allocating the transaction price to the performance obligations, and 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.

The revenue recognition standard is effective for the annual period beginning December 15, 2017, and for annual and interim periods thereafter. Earlier adoption is permitted only as of annual reporting periods beginning after December 15, 2016, including interim reporting periods within that reporting period. We must retroactively 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 amendment is adopted. We expect to adopt this guidance on January 1, 2018 and are continuing to evaluate the impact on our revenue recognition practices.

In November 2014, the FASB issued ASU 2014-16, *Derivatives and Hedging (Topic 815): Determining Whether the Host Contract in a Hybrid Financial Instrument Issued in the Form of a Share Is More Akin to Debt or to Equity (a consensus of the FASB Emerging Issues Task Force*). The amendments in this update clarify how current GAAP should be interpreted in evaluating the economic characteristics and risks of a host contract in a hybrid financial instrument that is issued in the form of a share. These amendments have been adopted, with no material impact on our consolidated financial statements or results of operations.

In February 2015, the FASB issued ASU 2015-02, *Consolidation (Topic 810): Amendments to the Consolidation Analysis*. The amendments in this update are intended to simplify the consolidation evaluation for reporting organizations that are required to evaluate whether they should consolidate certain legal entities and modify the evaluation of whether limited partnerships and similar legal entities are variable interest entities or voting interest entities. We are currently evaluating the effect of the amendments by revisiting our consolidation model for each of our less-than-wholly owned subsidiaries. The amendments are effective for us in the first quarter of 2016 and are not expected to have a material impact on our consolidated financial statements or related disclosures.

In April 2015, the FASB issued ASU 2015-03, *Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs.* The amendments in this update require that debt issuance costs related to a recognized debt liability (other than revolving credit facilities) be presented in the Consolidated Balance Sheets as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. This update deals solely with financial statement display matters; recognition and measurement of debt issuance costs are unaffected. Unamortized debt issuance costs of $38.3 million and $29.9 million for term loans and notes were included in Other long-term assets on the Consolidated Balance Sheets as of December 31, 2015 and December 31, 2014. In August 2015, the FASB issued ASU 2015-15, *Interest - Imputation of Interest (Subtopic 835-30): Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements*. The amendment clarifies ASU 2015-03 and provides that an entity may defer and present debt issuance costs for a line-of-credit or other revolving credit facility arrangement as an asset and subsequently amortize the deferred debt issuance costs ratably over the term of the arrangement, regardless of whether there are any outstanding borrowings on the arrangement. Unamortized debt issuance costs of $5.9 million and $7.4 million for revolving credit facilities were included in Other long-term assets on the Consolidated Balance Sheets as of December 31, 2015 and December 31, 2014. We will continue to include debt issuance costs for our line-of-credit and revolving credit facility arrangements in Other long-term assets upon adoption of ASU 2015-03. These amendments are effective for us on January 1, 2016.

In July 2015, the FASB issued ASU 2015-11, *Inventory (Topic 303): Simplifying the Measurement of Inventory. Topic 303* currently requires inventory to be measured at the lower of cost or market, where market could be replacement cost, net realizable value or net realizable value less a normal profit margin. The amendments in this update require that all inventory, excluding inventory that is measured using the last-in, first-out method or the retail inventory method, be measured at the lower of cost or net realizable value. Net realizable value is defined as the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. These amendments have been adopted, with no impact on our consolidated financial statements or results of operations.

In September 2015, the FASB issued ASU 2015-16, *Business Combinations (Topic 805): Simplifying the Accounting for Measurement-Period Adjustments.* Topic 805 currently requires that adjustments to provisional amounts recorded in a business combination be recognized retrospectively as if the accounting had been completed at the acquisition date. The amendments in this update require that an acquirer recognize these measurement-period adjustments in the reporting period in which the adjustment amounts are determined, with the effect on earnings of changes in depreciation, amortization or other income effects, if any, as a result of the change to the provisional amounts, calculated as if the accounting had been completed at the acquisition date. The amendments require disclosure of the amount recorded in current-period earnings that would have been recorded in previous reporting periods if the adjustment to the provisional amounts had been recognized as of the acquisition date. The amendments are effective for us in 2016, with early adoption permitted. We adopted the amendments on September 30, 2015 and have recognized the measurement-period adjustments for the Atlas mergers determined in the three months ended December 31, 2015 in current period earnings. See Note 4 – Business Acquisitions for additional information regarding the nature and amount of the measurement-period adjustments.

In November 2015, the FASB issued ASU 2015-17, *Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes*. The amendments in this update require that deferred tax asset and liabilities be classified as noncurrent on the Consolidated Balance Sheets. These amendments have been adopted, with no impact on our consolidated financial statements or results of operations.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)*. The amendments in this update require, among other things, that lessees recognize the following for all leases (with the exception of short-term leases) at the commencement date: (1) a lease liability, which is a lessee's obligation to make lease payments arising from a lease, measured on a discounted basis; and (2) a right-of-use asset, which is an asset that represents the lessee's right to use, or control the use of, a specified asset for the lease term. Lessees and lessors must apply a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. We expect to adopt the amendments in the first quarter of 2019 and are currently evaluating the impacts of the amendments to our financial statements and accounting practices for leases.

Factors That Significantly Affect Our Results

Our results of operations are substantially impacted by 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 annual and quarterly industry index prices for natural gas, selected NGL products and crude oil for the periods presented:

Average Quarterly & Annual Prices	Natural Gas $/MMBtu (1)	Illustrative Targa NGL $/gal (2)	Crude Oil $/Bbl (3)
2016			
1st Quarter (4)	$ 2.38	$ 0.33	$ 31.78
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**
2014			
4th Quarter	$ 4.04	$ 0.63	$ 73.12
3rd Quarter	4.07	0.84	97.21
2nd Quarter	4.68	0.88	102.98
1st Quarter	4.95	0.98	98.62
2014 Average	**4.43**	**0.83**	**92.99**
2013			
4th Quarter	$ 3.61	$ 0.92	$ 97.50
3rd Quarter	3.58	0.86	105.82
2nd Quarter	4.10	0.81	94.23
1st Quarter	3.34	0.86	94.35
2013 Average	**3.65**	**0.86**	**97.98**

(1) Natural gas prices are based on average quarterly and annual prices from Henry Hub I-FERC commercial index prices.
(2) NGL prices are based on quarterly weighted average prices and annual averages of prices from Mont Belvieu Non-TET monthly commercial index prices. Illustrative Targa NGL contains 37% ethane, 35% propane, 10% natural gasoline, 6% isobutane and 12% normal butane.
(3) Crude oil prices are based on quarterly weighted average prices and annual averages of daily prices from West Texas Intermediate commercial index prices as measured on the NYMEX.
(4) Prices for the first quarter of 2016 are based on the monthly average price for January 2016.

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 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

Because of the potential for significant volatility of natural gas and NGL prices, the contract mix of our Gathering and Processing division, other than fee-based contracts in Badlands and other gathering and processing business units and certain other gathering and processing services, can have a material 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 the commodities handled ("equity volumes").

Contract terms in the Gathering and Processing division 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. For example, our Badlands and SouthTX crude oil and natural gas contracts are essentially 100% fee-based.

The contract terms and contract mix of our Downstream Business can also have a significant impact on our results of operations. During periods of low relative demand for available fractionation capacity, rates were low and frac-or-pay contracts were not readily available. The current demand for fractionation services has grown resulting in increases in fractionation fees and contract term. In addition, reservation fees are required. Increased demand for export services also supports fee-based contracts. Contracts in the Logistics Assets segment are primarily fee-based arrangements while the Marketing and Distribution segment includes both fee-based and percent-of-proceeds 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 through 2018 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 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. We actively manage the Downstream Business product inventory and other working capital levels to reduce exposure to changing NGL 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. Continued expansion of existing assets will also give rise to additional operating expenses, which will affect our results. The employees supporting our operations are employees of Targa Resources LLC, a Delaware limited liability company, and an indirect wholly-owned subsidiary of Targa. We reimburse Targa for the payment of certain operating expenses, including compensation and benefits of operating personnel assigned to our assets.

General and Administrative Expenses

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

General Trends and Outlook

We expect the midstream energy business environment to continue to be affected by the following key trends: demand for our products and services, commodity prices, volatile capital markets 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 affect production rates and investments by third parties in the development of oil and natural gas reserves. Generally, drilling and production activity will increase as energy prices increase. The recent substantial decline in oil, condensate, NGL and natural gas prices has led many exploration and production companies to reduce planned capital expenditures for drilling and production activities during 2016. In our Field Gathering and Processing areas of operation, producers have reduced and are likely to continue reducing their drilling activity to varying degrees, which may lead to lower oil, condensate, NGL and natural gas volume growth in the near term and reduced demand for our services. Producer activity generates demand in our Downstream Business for fractionation and other fee-based services, which may decrease in the near term. As prices have declined, demand for our international export, storage and terminaling services has remained relatively constant, 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 significant 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 fourth quarter of 2014 and continuing in 2015, there has been a significant decline in commodity prices. We can not predict how long this decline in commodity prices will extend. 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 2016, 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 acquisition and 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 “Item 1A. Risk Factors—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.” 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 revenues. Our growth strategy, based on expansion of existing facilities as well as third-party acquisitions of businesses and assets, has increased the percentage of our revenues that are fee-based. Fixed fees for services such as fractionation, storage, terminaling and crude oil gathering are not directly tied to changes in market prices for commodities.

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

Throughput Volumes, Facility Efficiencies and Fuel Consumption

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

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

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

Operating Expenses

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

Capital Expenditures

Capital projects associated with growth and maintenance projects are closely monitored. Return on investment is analyzed before a capital project is approved, spending is closely monitored throughout the development of the project, and the subsequent operational performance is compared to the assumptions used in the economic analysis performed for the capital investment approval. We have seen a substantial increase in our total capital spent since 2010 and currently have significant internal growth projects.

Gross Margin

We define gross margin as revenues less purchases. It is impacted by volumes and commodity prices as well as by our contract mix and commodity hedging program. We define Gathering and Processing gross margin as total operating revenues from (1) the sale of natural gas, condensate, crude oil and NGLs and (2) natural gas and crude oil gathering and service fee revenues, less product purchases, which consist primarily of producer payments and other natural gas and crude oil purchases. Logistics Assets gross margin consists primarily of service fee revenue. Gross margin for Marketing and Distribution equals total revenue from service fees, NGL and natural gas sales, less cost of sales, which consists primarily of NGL and natural gas purchases, transportation costs and changes in inventory valuation. The gross margin impacts of cash flow hedge settlements are reported in Other.

Operating Margin

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

Management reviews business segment gross margin and operating margin monthly as a core internal management process. We believe that investors benefit from having access to the same financial measures that our 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 us 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 to 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 attributable to Targa Resources Partners LP before: interest; income taxes; depreciation and amortization; impairment of goodwill; gains or losses on debt repurchases, redemptions, amendments, exchanges and early debt extinguishments and asset disposals; risk management activities related to derivative instruments, including the cash impact of hedges acquired in the APL merger; non-cash compensation on TRP equity grants; transaction costs related to business acquisitions; earnings/losses from unconsolidated affiliates net of distributions, distributions from preferred interests and the noncontrolling interest portion of depreciation and amortization expenses. Adjusted EBITDA is used as a supplemental financial measure by us and by external users of our financial statements such as investors, commercial banks and others. The economic substance behind our use of Adjusted EBITDA is to measure the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and make distributions to our investors.

Adjusted EBITDA is a non-GAAP financial measure. The GAAP measures most directly comparable to Adjusted EBITDA are net cash provided by operating activities and net income attributable to Targa Resources Partners LP. Adjusted EBITDA should not be considered as an alternative to GAAP net cash provided by operating activities or 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 net cash provided by operating activities 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 net income attributable to Targa Resources Partners LP plus depreciation and amortization, impairment of goodwill, deferred taxes and amortization of debt issuance costs included in interest expense, adjusted for non-cash risk management activities related to derivative instruments, including the cash impact of hedges acquired in the APL merger; debt repurchases, redemptions, amendments, exchanges and early debt extinguishments; non-cash compensation on TRP equity grants; changes in fair value of contingent consideration and mandatorily redeemable preferred interests; transaction costs related to business acquisitions; earnings/losses from unconsolidated affiliates net of distributions and asset disposals and less maintenance capital expenditures (net of any reimbursements of project costs). This measure includes any impact of noncontrolling interests.

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 the board of directors of our general partner) to the cash distributions we expect to pay our limited partners. Using this metric, management and external users of our financial statements can quickly compute the coverage ratio of estimated cash flows to cash distributions. Distributable cash flow is also an important financial measure for our limited partners 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 distribution rates. Distributable cash flow is also a quantitative standard used throughout the investment community with respect to publicly-traded partnerships and limited liability companies because the value of a unit of such an entity is generally determined by the unit's yield (which in turn is based on the amount of cash distributions the entity pays to a limited partner).

Distributable cash flow is a non-GAAP financial measure. The GAAP measure most directly comparable to distributable cash flow is net income attributable to Targa Resources Partners LP. Distributable cash flow should not be considered as an alternative to GAAP net income attributable to Targa Resources Partners LP. 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 its decision-making processes.

The following tables reconcile the non-GAAP financial measures used by management to the most directly comparable GAAP measures for the periods indicated:

	2015	2014	2013
		(In millions)	
Reconciliation of Targa Resources Partners LP gross margin and operating margin to net income (loss):			
Gross margin	$ 1,785.6	$ 1,569.6	$ 1,177.7
Operating expenses	(504.6)	(433.0)	(376.2)
Operating margin	1,281.0	1,136.6	801.5
Depreciation and amortization expenses	(677.1)	(346.5)	(271.6)
General and administrative expenses	(153.6)	(139.8)	(143.1)
Provisional goodwill impairment	(290.0)	-	-
Interest expense, net	(207.8)	(143.8)	(131.0)
Income tax expense	(0.6)	(4.8)	(2.9)
Gain (loss) on sale or disposition of assets	8.0	4.8	(3.9)
Gain (loss) from financing activities	2.8	(12.4)	(14.7)
Change in contingent consideration	1.2	-	15.3
Other, net	(23.2)	11.0	9.0
Net income (loss)	$ (59.3)	$ 505.1	$ 258.6

	2015	2014	2013
		(In millions)	
Reconciliation of Net Income (Loss) to Adjusted EBITDA			
Net income (loss) attributable to Targa Resources Partners LP	$ (27.4)	$ 467.7	$ 233.5
Interest expense, net	207.8	143.8	131.0
Income tax expense	0.6	4.8	2.9
Depreciation and amortization expenses	677.1	346.5	271.6
Provisional goodwill impairment	290.0	-	-
(Gain) loss on sale or disposition of assets	(8.0)	(4.8)	3.9
(Gain) loss from financing activities	(2.8)	12.4	14.7
(Earnings) loss from unconsolidated affiliates (1)	2.5	(18.0)	(12.0)
Distributions from unconsolidated affiliates and preferred partner interests (1)	21.1	18.0	12.0
Change in contingent consideration	(1.2)	-	(15.3)
Compensation on TRP equity grants (1)	16.6	9.2	6.0
Transaction costs related to business acquisitions (1)	19.2	-	-
Risk management activities	64.8	4.7	(0.5)
Other	0.6	-	-
Noncontrolling interests adjustment (2)	(69.7)	(14.0)	(12.6)
Targa Resources Partners LP Adjusted EBITDA	$ 1,191.2	$ 970.3	$ 635.2

(1) The definition of Adjusted EBITDA was revised in 2014 to exclude non-cash compensation on equity grants and in 2015 to exclude earnings from unconsolidated investments net of distributions and transaction costs related to business acquisitions.
(2) Noncontrolling interest portion of depreciation and amortization expenses.

	2015	2014	2013
		(In millions)	
Reconciliation of net cash provided by Targa Resources Partners LP operating activities to Adjusted EBITDA:			
Net cash provided by operating activities	$ 1,083.9	$ 838.5	$ 411.4
Net income attributable to noncontrolling interests	31.9	(37.4)	(25.1)
Interest expense	207.8	143.8	131.0
Non-cash interest expense, net (1)	(12.6)	(11.2)	(15.5)
(Earnings) loss from unconsolidated affiliates (2)	2.5	(18.0)	(12.0)
Distributions from unconsolidated affiliates and preferred interests (2)	21.1	18.0	12.0
Transaction costs related to business acquisitions (2)	19.2	-	-
Current income tax expense	0.8	3.2	2.0
Other (3)	(67.6)	(18.4)	(13.7)
Changes in operating assets and liabilities which used (provided) cash:			
Accounts receivable and other assets	(277.5)	(58.6)	230.3
Accounts payable and other liabilities	181.7	110.4	(85.2)
Targa Resources Partners LP Adjusted EBITDA	$ 1,191.2	$ 970.3	$ 635.2

(1) Includes amortization of debt issuance costs, discount and premium.
(2) The definition of Adjusted EBITDA was revised in 2014 to exclude non-cash compensation on equity grants and in 2015 to exclude earnings from unconsolidated investments net of distributions and transaction costs related to business acquisitions.
(3) Includes accretion expense associated with asset retirement obligations, noncontrolling interest portion of depreciation and amortization expenses and gain or loss on financing activities.

	2015	2014	2013
		(In millions)	
Reconciliation of net income (loss) to Distributable Cash flow:			
Net income (loss) attributable to Targa Resources Partners LP	$ (27.4)	$ 467.7	$ 233.5
Depreciation and amortization expenses	677.1	346.5	271.6
Provisional goodwill impairment	290.0	-	-
Deferred income tax expense (benefit)	(0.2)	1.6	0.9
Non-cash interest expense, net (1)	12.6	11.2	15.5
(Gain) loss from financing activities	(2.8)	12.4	14.7
(Earnings) loss from unconsolidated affiliates (2)	2.5	(18.0)	(12.0)
Distributions from unconsolidated affiliates (2)	15.0	18.0	12.0
Compensation on TRP equity grants (2)	16.6	9.2	6.0
Change in redemption value of other long-term liabilities	(30.6)	-	-
Change in contingent consideration	(1.2)	-	(15.3)
(Gain) loss on sale or disposition of assets	(8.0)	(4.8)	3.9
Risk management activities	64.8	4.7	(0.5)
Maintenance capital expenditures	(97.9)	(79.1)	(79.9)
Transactions costs related to business acquisitions (2)	19.2	-	-
Other (3)	(61.9)	(6.2)	(4.1)
Targa Resources Partners LP distributable cash flow	$ 867.8	$ 763.2	$ 446.3

(1) Includes amortization of debt issuance costs, discount and premium.
(2) The definition of distributable cash flow was revised in 2014 to exclude non-cash compensation on equity grants and in 2015 to exclude earnings from unconsolidated investments net of distributions and transaction costs related to business acquisitions.
(3) Includes the noncontrolling interests portion of maintenance capital expenditures, depreciation and amortization expenses.

Consolidated Results of Operations

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

	2015	2014	2013	2015 vs. 2014		2014 vs. 2013	
	($ in millions, except operating statistics and price amounts)						
Revenues:							
Sales of commodities	$ 5,465.4	$ 7,595.2	$ 5,728.2	$ (2,129.8)	28%	$ 1,867.0	33%
Fees from midstream services	1,193.2	1,021.3	586.7	171.9	17%	434.6	74%
Total revenues	6,658.6	8,616.5	6,314.9	(1,957.9)	23%	2,301.6	36%
Product purchases	4,873.0	7,046.9	5,137.2	(2,173.9)	31%	1,909.7	37%
Gross margin (1)	1,785.6	1,569.6	1,177.7	216.0	14%	391.9	33%
Operating expenses	504.6	433.0	376.2	71.6	17%	56.8	15%
Operating margin (2)	1,281.0	1,136.6	801.5	144.4	13%	335.1	42%
Depreciation and amortization expenses	677.1	346.5	271.6	330.6	95%	74.9	28%
General and administrative expenses	153.6	139.8	143.1	13.8	10%	(3.3)	2%
Provisional goodwill impairment	290.0	-	-	290.0	0%	-	-
Other operating (income) expenses	(7.1)	(3.0)	9.6	(4.1)	137%	(12.6)	131%
Income from operations	167.4	653.3	377.2	(485.9)	74%	276.1	73%
Interest expense, net	(207.8)	(143.8)	(131.0)	(64.0)	45%	(12.8)	10%
Equity earnings	(2.5)	18.0	14.8	(20.5)	114%	3.2	22%
Gain (loss) from financing activities	2.8	(12.4)	(14.7)	15.2	123%	2.3	16%
Other income (expense)	(18.6)	(5.2)	15.2	(13.4)	NM	(20.4)	134%
Income tax (expense) benefit	(0.6)	(4.8)	(2.9)	4.2	88%	(1.9)	66%
Net income (loss)	(59.3)	505.1	258.6	(564.4)	112%	246.5	95%
Less: Net income attributable to noncontrolling interests	(31.9)	37.4	25.1	(69.3)	185%	12.3	49%
Net income (loss) attributable to limited partners and the general partners	$ (27.4)	$ 467.7	$ 233.5	$ (495.1)	106%	$ 234.2	100%
Financial and operating data:							
Financial data:							
Adjusted EBITDA (3)	$ 1,191.2	$ 970.3	$ 635.2	$ 220.9	23%	$ 335.1	53%
Distributable cash flow (4)	867.8	763.2	446.3	104.6	14%	316.9	71%
Capital expenditures	777.2	747.8	1,034.5	29.4	4%	(286.7)	28%
Operating statistics:							
Crude oil gathered, MBbl/d	106.3	93.5	46.9	12.8	14%	46.6	99%
Plant natural gas inlet, MMcf/d (5)(6)(7)	3,241.3	2,109.5	2,110.2	1,131.8	54%	(0.7)	-
Gross NGL production, MBbl/d (7)	265.5	153.0	136.8	112.5	74%	16.2	12%
Export volumes, MBbl/d (8)	183.0	176.9	66.6	6.1	3%	110.3	166%
Natural gas sales, BBtu/d (6)(7)	1,770.7	902.3	928.2	868.4	96%	(25.9)	3%
NGL sales, MBbl/d (7)	517.0	419.5	294.8	97.5	23%	124.7	42%
Condensate sales, MBbl/d (7)	9.3	4.4	3.5	4.9	111%	0.9	26%

(1) Gross margin is a non-GAAP financial measure and is discussed under “Management’s Discussion and Analysis of Financial Condition and Results of Operations – How We Evaluate Our Operations.”

(2) Operating margin is a non-GAAP financial measure and is discussed under “Management’s Discussion and Analysis of Financial Condition and Results of Operations – How We Evaluate Our Operations.”

(3) Adjusted EBITDA is net income attributable to Targa Resources Partners LP before: interest, income taxes, depreciation and amortization, impairment of goodwill, gains or losses on financing activities and asset disposals, risk management activities related to derivative instruments including the cash impact of hedges acquired in the APL Merger, non-cash compensation on Partnership equity grants, transactions costs related to acquisitions, earnings/losses from unconsolidated affiliates net of distributions, distributions from preferred interests and the noncontrolling interest portion of depreciation and amortization expenses. This is a non-GAAP financial measure and is discussed under “Management’s Discussion and Analysis of Financial Condition and Results of Operations – How We Evaluate Our Operations.”

(4) Distributable cash flow is income attributable to Targa Resources Partners LP plus depreciation and amortization, impairment of goodwill, deferred taxes and amortization of debt issuance costs included in interest expense, adjusted for non-cash risk management activities related to derivative instruments including the cash impact of hedges acquired in the APL merger, financing activities, non-cash compensation on Partnership equity grants, transaction costs related to acquisitions, earnings/losses from unconsolidated affiliates net of distributions and asset disposals, change in redemptive value of mandatorily redeemable preferred interests and less maintenance capital expenditures (net of any reimbursements of project costs). This measure includes any impact of noncontrolling interests. This is a non-GAAP financial measure and is discussed under “Management’s Discussion and Analysis of Financial Condition and Results of Operations – How We Evaluate Our Operations.”

(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) These volume statistics are presented with the numerator as the total volume sold during the quarter and the denominator as the number of calendar days during the quarter.
(8) 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.

2015 Compared to 2014

Revenues from commodity sales declined as the effect of significantly lower commodity prices ($6,318.1 million) exceeded the favorable impacts of inclusion of ten months of operations of TPL ($1,260.5 million), other volume increases ($2,934.0 million), and favorable hedge settlements ($84.2 million). Fee-based and other revenues increased due to the inclusion of TPL's fee revenue ($179.7 million), which were partially offset by lower export fees.

Offsetting lower commodity revenues was a commensurate reduction in product purchases due to significantly lower commodity costs ($3,280.0 million). 2015 also included product purchases related to TPL's operations ($1,106.1 million).

The higher gross margin in 2015 was attributable to inclusion of TPL operations, increased throughput related to other system expansions in our Field Gathering and Processing segment, recognition of a renegotiated commercial contract and increased terminaling and storage fees, partially offset by lower fractionation and export margin in our Logistics and Marketing segments. Higher operating expenses are due to the inclusion of TPL's operations ($101.6 million), which more than offset the cost savings generated throughout our other operating areas ($31.0 million). See "—Results of Operations—By Reportable Segment" for additional information regarding changes in gross margin and operating margin on a segment basis.

The increase in depreciation and amortization expenses reflects the impact of TPL, the planned increased amortization of the Badlands intangible assets and growth investments placed in service after 2014, including the international export expansion project, continuing development at Badlands and other system expansions. During 2015, we recorded an additional $32.6 million charge to depreciation to reflect an impairment of certain gas processing facilities and associated gathering systems in the Coastal Gathering and Processing segment as a result of reduced forecasted processing volumes due to current market conditions and processing spreads in Louisiana.

Higher general and administrative expense are due to the inclusion of TPL general and administrative costs ($32.1 million), which was partially offset by other general and administrative reductions ($18.1 million), primarily from lower compensation and related costs.

The increase in other operating gains during 2015 was primarily related to higher gains on sales of assets.

During 2015, we recognized a provisional loss of $290.0 million associated with the provisional impairment of goodwill in our Field and Gathering segment.

The increase in net interest expense primarily reflects higher borrowings attributable to the APL merger and lower capitalized interest associated with major capital projects compared to 2014. These factors were partially offset by the change in the estimated redemption value ($30.6 million) of the mandatorily redeemable preferred interests in the WestTX and WestOK joint ventures acquired in the Atlas mergers.

During 2015, the gain on financing activities was due primarily to $3.6 million in gains on repurchase of debt offset by a $0.7 million loss the APL notes exchange offer. In 2014, the loss on financing activities was due to the redemption of our 7⅞% senior notes.

Net income attributable to noncontrolling interests decreased due to lower earnings in 2015 at our joint ventures: Cedar Bayou Fractionators, VESCO, and Versado. The inclusion of noncontrolling interest from TPL's Centrahoma joint venture, which included their portion of the goodwill impairment, also decreased the net income attributable to noncontrolling interests.

2014 Compared 2013

Higher revenues, including the impact of hedging (a $29.4 million decrease to revenues), were primarily due to higher NGL volumes ($1,778.6 million), higher fee-based and other revenues ($438.1 million) and higher natural gas commodity sales prices ($201.4 million), partially offset by lower NGL and condensate prices ($65.6 million).

Higher gross margin in 2014 reflects increased export activities and higher fractionation fees in our Logistics and Marketing segments and increased Field Gathering and Processing throughput volumes associated with system expansions and increased producer activity, as well as higher natural gas prices. This significant growth in our asset base brought a higher level of operating expenses in 2014. See "—Results of Operations—By Reportable Segment" for additional information regarding changes in gross margin and operating margin on a segment basis.

The increase in depreciation and amortization expenses reflects increased amortization of the Badlands intangible assets and higher depreciation related to major organic investments placed in service, including continuing development at Badlands, the international export expansion project, High Plains and Longhorn plants, CBF Train 4 and other system expansions.

General and administrative expenses were slightly lower due to the effect of lower non-cash expenses related to periodic valuations of unvested Long Term Incentive Plan awards which offset increases in other overhead costs.

The increase in other operating income primarily relates to an insurance settlement in 2014 compared to losses on asset disposals recorded in 2013.

The increase in interest expense reflects higher outstanding borrowings and lower capitalized interest allocated to our major expansion projects, partially offset by lower overall interest rates.

Losses from financing activities reflect premiums paid and the write-off of associated unamortized debt issuance costs related to the redemptions of our 7⅞% Notes in 2014 and the outstanding balance of our 11¼% Notes and $100 million of our 6⅜% Notes in 2013.

Other expense in 2014 was primarily attributable to transaction costs related to the pending Atlas mergers. In 2013 we recorded a gain from the elimination of a contingent consideration liability associated with the Badlands acquisition.

Net income attributable to noncontrolling interests increased as our joint ventures experienced higher earnings in 2014.

Results of Operations—By Reportable Segment

Our operating margins by reportable segment are:

	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Total
			(In millions)			
2015	$ 484.8	$ 30.3	$ 439.5	$ 242.2	$ 84.2	$ 1,281.0
2014	372.3	77.6	445.1	249.6	(8.0)	1,136.6
2013	270.5	85.4	282.3	141.9	21.4	801.5

Gathering and Processing Segments

Field Gathering and Processing

	2015	2014	2013	2015 vs. 2014		2014 vs. 2013	
				($ in millions)			
Gross margin	$ 760.3	$ 563.2	$ 435.7	$ 197.1	35%	$ 127.5	29%
Operating expenses	275.5	190.9	165.2	84.6	44%	25.7	16%
Operating margin	$ 484.8	$ 372.3	$ 270.5	$ 112.5	30%	$ 101.8	38%
Operating statistics (1):							
Plant natural gas inlet, MMcf/d (2),(3)							
SAOU (4)(5)	234.0	193.1	154.1	40.9	21%	39.0	25%
WestTX (6)	374.0	-	-	374.0	NM	-	-
Sand Hills (5)	163.0	165.1	155.8	(2.1)	1%	9.3	6%
Versado	183.2	169.6	156.4	13.6	8%	13.2	8%
SouthTX (6)	120.0	-	-	120.0	NM	-	-
North Texas (7)	347.6	354.5	292.4	(6.9)	2%	62.1	21%
SouthOK (6)	401.5	-	-	401.5	NM	-	-
WestOK (6)	471.7	-	-	471.7	NM	-	-
Badlands (8)	49.2	38.9	21.4	10.3	26%	17.5	82%
	2,344.2	921.2	780.1	1,423.0	154%	141.1	18%
Gross NGL production, MBbl/d (3)							
SAOU	27.3	25.2	22.5	2.1	8%	2.7	12%
WestTX (6)	43.4	-	-	43.4	NM	-	-
Sand Hills	17.4	18.0	17.5	(0.6)	3%	0.5	3%
Versado	23.4	21.4	18.9	2.0	9%	2.5	13%
SouthTX (6)	13.8	-	-	13.8	NM	-	-
North Texas	39.6	37.8	31.1	1.8	5%	6.7	22%
SouthOK (6)	28.1	-	-	28.1	NM	-	-
WestOK (6)	23.8	-	-	23.8	NM	-	-
Badlands	6.8	3.5	1.9	3.3	94%	1.6	84%
	223.6	105.9	91.9	117.7	111%	14.0	15%
Crude oil gathered, MBbl/d	106.3	93.5	46.9	12.8	14%	46.6	99%
Natural gas sales, BBtu/d (3)	1,340.8	469.0	376.3	871.8	186%	92.7	25%
NGL sales, MBbl/d	176.9	80.7	71.4	96.2	119%	9.3	13%
Condensate sales, MBbl/d	8.3	3.6	3.2	4.7	131%	0.4	13%
Average realized prices (9):							
Natural gas, $/MMBtu	2.32	4.05	3.44	(1.73)	43%	0.61	18%
NGL, $/gal	0.34	0.72	0.76	(0.38)	53%	(0.04)	5%
Condensate, $/Bbl	41.29	82.35	92.89	(41.06)	50%	(10.54)	11%

(1) Segment operating statistics include the effect of intersegment amounts, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume sold during the quarter and the denominator is the number of calendar days during the quarter, including the volumes related to plants acquired in the APL merger.
(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.
(3) Plant natural gas inlet volumes and gross NGL production volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.
(4) Includes volumes from the 200 MMcf/d cryogenic High Plains plant which started commercial operations in June 2014.
(5) Includes wellhead gathered volumes moved from Sand Hills via pipeline to SAOU for processing.
(6) Operations acquired as part of the APL merger effective February 27, 2015.
(7) Includes volumes from the 200 MMcf/d cryogenic Longhorn plant which started commercial operations in May 2014.
(8) Badlands natural gas inlet represents the total wellhead gathered volume.
(9) Average realized prices exclude the impact of hedging activities presented in Other.

2015 Compared to 2014

The increase in gross margin was primarily due to the inclusion of the TPL volumes along with other volume increases partially offset by significantly lower commodity prices. The increases in plant inlet volumes at SAOU, Sand Hills (see footnote (5) above) and Versado were driven by system expansions and by increased producer activity which increased available supply across our areas of operation partially offset by reduced producer activity and volumes in North Texas. 2015 benefited from a full year operations of the Longhorn plant in North Texas, the High Plains plant in SAOU and the Little Missouri 3 plant in Badlands. Badlands crude oil and natural gas volumes increased significantly due to plant and system expansion and increased producer activity.

Excluding the addition of operating expenses for TPL, operating expenses for other areas were significantly lower, even with system expansions, due to focused cost reduction efforts.

2014 Compared to 2013

Gross margin improvements in our Field Gathering and Processing segment were fueled by throughput increases and higher natural gas sales prices partially offset by lower NGL and condensate sales prices and the impact of severe cold weather in the first quarter of 2014. The increase in plant inlet volumes was driven by system expansions and by increased producer activity which increased available supply across our areas of operation. Gross margin in 2014 also benefited from the second quarter start-up of commercial operations at the Longhorn Plant in North Texas and the High Plains Plant in SAOU. Badlands crude oil and natural gas volumes increased significantly due to producer activities and system expansion. Higher NGL sales reflect similar factors.

Higher operating expenses were primarily driven by volume growth and system expansions and included additional labor costs, ad valorem taxes and compression and system maintenance expenses.

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 Gathering and Processing segment:

	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	100.0%	234.0	234.0	-	234.0
WestTX (6)(7)	612.8	72.8%	446.1	446.1	(72.1)	374.0
Sand Hills	163.0	100.0%	163.0	163.0	-	163.0
Versado (8)	183.2	63.0%	115.4	183.2	-	183.2
SouthTX (6)	143.1	100.0%	143.1	143.1	(23.1)	120.0
North Texas	347.6	100.0%	347.6	347.6	-	347.6
SouthOK (6)	478.9	Varies (9)	398.6	478.9	(77.4)	401.5
WestOK (6)	562.6	100.0%	562.6	562.6	(90.9)	471.7
Badlands (10)	49.2	100.0%	49.2	49.2	-	49.2
Total	2,774.5		2,459.7	2,607.8	(263.6)	2,344.2
Gross NGL production, MBbl/d (2)						
SAOU	27.3	100.0%	27.3	27.3	-	27.3
WestTX (6)(7)	71.1	72.8%	51.8	51.8	(8.4)	43.4
Sand Hills	17.4	100.0%	17.4	17.4	-	17.4
Versado	23.4	63.0%	14.7	23.4	-	23.4
SouthTX (6)	16.5	100.0%	16.5	16.5	(2.7)	13.8
North Texas	39.6	100.0%	39.6	39.6	-	39.6
SouthOK (6)	33.5	Varies (9)	29.1	33.5	(5.4)	28.1
WestOK (6)	28.4	100.0%	28.4	28.4	(4.6)	23.8
Badlands	6.8	100.0%	6.8	6.8	-	6.8
Total	264.0		231.5	244.6	(21.0)	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, while natural gas sales exclude 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.
(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.

Coastal Gathering and Processing

	2015	2014	2013	2015 vs. 2014		2014 vs. 2013	
				($ in millions)			
Gross margin	$ 69.8	$ 123.8	$ 132.3	$ (54.0)	44%	$ (8.5)	6%
Operating expenses	39.5	46.2	46.9	(6.7)	15%	(0.7)	1%
Operating margin	$ 30.3	$ 77.6	$ 85.4	$ (47.3)	61%	$ (7.8)	9%
Operating statistics (1):							
Plant natural gas inlet, MMcf/d (2),(3)							
LOU	200.1	284.6	350.9	(84.5)	30%	(66.3)	19%
VESCO	442.4	509.0	515.5	(66.6)	13%	(6.5)	1%
Other Coastal Straddles	254.5	394.8	463.7	(140.3)	36%	(68.9)	15%
	897.0	1,188.4	1,330.1	(291.4)	25%	(141.7)	11%
Gross NGL production, MBbl/d (3)							
LOU	7.2	9.0	10.2	(1.8)	20%	(1.2)	12%
VESCO	26.6	26.0	21.5	0.6	2%	4.5	21%
Other Coastal Straddles	8.0	12.1	13.2	(4.1)	34%	(1.1)	8%
	41.8	47.1	44.9	(5.3)	11%	2.2	5%
Natural gas sales, BBtu/d (3)	237.1	258.0	296.0	(20.9)	8%	(38.0)	13%
NGL sales, MBbl/d	31.4	40.2	41.8	(8.8)	22%	(1.6)	4%
Condensate sales, MBbl/d	0.8	0.7	0.4	0.1	14%	0.3	75%
Average realized prices:							
Natural gas, $/MMBtu	2.69	4.44	3.73	(1.75)	39%	0.71	19%
NGL, $/gal	0.39	0.80	0.83	(0.41)	51%	(0.03)	4%
Condensate, $/Bbl	47.72	89.70	104.38	(41.98)	47%	(14.68)	14%

(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 during the applicable reporting period and the denominator is the number of calendar days during the applicable reporting period.
(2) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.
(3) Plant natural gas inlet volumes and gross NGL production volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.

2015 Compared to 2014

The decrease in Coastal Gathering and Processing gross margin was primarily due to lower NGL prices, a less favorable frac spread and lower throughput volumes partially offset by new volumes at LOU and VESCO with higher average GPM.

Operating expenses decreased primarily due to reduced volumes and lower plant run-time due to current market conditions.

2014 Compared to 2013

The decrease in Coastal Gathering and Processing gross margin was primarily due to lower NGL sales prices, less favorable frac spreads and lower throughput volumes partially offset by new volumes at VESCO with higher GPM and the availability of short-term higher GPM off-system volumes at LOU. The overall decrease in plant inlet volumes was largely attributable to the decline of leaner off-system supply volumes and the idling of the Big Lake plant in November 2014 due to market conditions. Gross NGL production at VESCO during 2013 was impacted by a third-party NGL takeaway pipeline volume constraint.

Operating expenses were relatively flat.

Logistics and Marketing Segments

Logistics Assets

	2015	2014	2013	2015 vs. 2014		2014 vs. 2013	
				($ in millions)			
Gross margin (1)	$ 613.9	$ 613.3	$ 408.2	$ 0.6	0%	$ 205.1	50%
Operating expenses (1)	174.4	168.2	125.9	6.2	4%	42.3	34%
Operating margin	$ 439.5	$ 445.1	$ 282.3	$ (5.6)	1%	$ 162.8	58%
Operating statistics MBbl/d (2):							
Fractionation volumes (3)	342.7	350.0	287.6	(7.3)	2%	62.4	22%
LSNG treating volumes	22.4	23.4	20.1	(1.0)	4%	3.3	16%
Benzene treating volumes	22.4	23.4	17.5	(1.0)	4%	5.9	34%

(1) 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 segment results include effects of variable energy costs that impact both gross margin and operating expenses.
(2) 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.
(3) Fractionation volumes reflect those volumes delivered and settled under fractionation contracts.

2015 Compared to 2014

Logistics Assets gross margin was flat due to the recognition of the renegotiated commercial arrangements related to our crude and Channelview Splitter project and increased terminaling and storage activities offset by lower LPG export and fractionation margins. Slightly higher LPG export volumes (which are reflected in both the Logistics Assets and Marketing and Distribution segments), averaged 183 MBbl/d in 2015 compared to 177 MBbl/d last year.

Fractionation gross margin was lower due to the variable effects of fuel and power, which are largely reflected in lower operating expenses (see footnote (1) above), and by a decrease in supply volume. Terminaling and storage volumes increased due to higher customer throughput.

Operating expenses increased due to lower system product gains and higher maintenance, partially offset by lower fuel and power expense and lower export-related costs.

2014 Compared to 2013

Logistics Assets gross margin was significantly higher due to increased LPG export activity and increased fractionation activities, despite the increasing impact of ethane rejection. LPG export volumes, which benefit both the Logistics Assets and Marketing and Distribution segments, averaged 177 MBbl/d in 2014 compared to 67 MBbl/d for 2013. This increase was driven by Phase I of our international export expansion project coming on-line in September 2013 and Phase II coming on-line during the second quarter and third quarter of 2014. Higher fractionation volumes were primarily due to CBF Train 4, which became operational in the third quarter of 2013. Treating volumes improved in 2014 compared to 2013 due to higher customer throughput. Terminaling and storage activity also increased, and capacity reservation fees were higher.

Higher operating expenses reflect the expansion of our export and fractionation facilities, and increased fuel and power costs. Partially offsetting these factors were higher system product gains in 2014.

Marketing and Distribution

	2015	2014	2013	2015 vs. 2014		2014 vs. 2013	
				($ in millions)			
Gross margin	$ 283.8	$ 298.0	$ 185.2	$ (14.2)	5%	$ 112.8	61%
Operating expenses	41.6	48.4	43.3	(6.8)	14%	5.1	12%
Operating margin	$ 242.2	$ 249.6	$ 141.9	$ (7.4)	3%	$ 107.7	76%
Operating statistics (1):							
NGL sales, MBbl/d	432.3	423.3	296.6	9.0	2%	126.7	43%
Average realized prices:							
NGL realized price, $/gal	0.46	0.93	0.94	(0.47)	51%	(0.01)	1%

(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 applicable reporting period and the denominator is the number of calendar days during the applicable reporting period.

2015 Compared to 2014

Marketing and Distribution gross margin decreased primarily due to a lower price environment and the expiration and recognition of a contract settlement in 2014. The lower gross margin was partially offset by higher LPG export margin, higher marketing gains and higher terminal activity. Slightly higher LPG export volumes are reflected in both the Logistics Assets and Marketing and Distribution segments.

Operating expenses decreased due to lower barge expense and lower terminal expense.

2014 Compared to 2013

Marketing and Distribution gross margin increased primarily due to higher LPG export activity (which benefits both Logistics Assets and Marketing and Distribution segments), higher Wholesale and NGL marketing activities, higher terminal activity, higher barge utilization including an increased barge fleet, and increased refinery services. Gross margin was partially offset by lower truck utilization and a reduced benefit associated with a contract settlement.

Operating expenses increased primarily due to higher terminal activity, higher barge and railcar utilization partially offset by lower truck utilization.

Other

	2015	2014	2013	2015 vs. 2014	2014 vs. 2013
			($ in millions)		
Gross margin	$ 84.2	$ (8.0)	$ 21.4	$ 92.2	$ (29.4)
Operating margin	$ 84.2	$ (8.0)	$ 21.4	$ 92.2	$ (29.4)

Other contains the results (including any hedge ineffectiveness) of commodity derivative activities included in operating margin and mark-to-market gain/losses related to derivative contracts that were not designated as cash-flow hedges. Eliminations of inter-segment transactions are reflected in the corporate and eliminations column. 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 hedged the commodity price associated with a portion of our expected (i) natural gas equity volumes in Field Gathering and Processing Operations and (ii) NGL and condensate equity volumes predominately in Field Gathering and Processing as well as in the LOU portion of the Coastal Gathering and Processing Operations that result from percent of proceeds or liquid processing arrangements by entering into derivative instruments. Because we are essentially forward-selling a portion of our 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:

	2015			2014			2013		
	(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)	51.8	$ 0.71/MMBtu	$ 37.0	21.9	$ (0.27)/MMBtu	$ (5.9)	$ 12.3	$ 0.95/MMBtu	$ 11.7
NGL (MMBbl)	76.4	0.29/Bbl	22.1	0.6	5.79/Bbl	3.6	2.1	6.19/Bbl	12.8
Crude Oil (MMBbl)	0.8	9.37/Bbl	21.6	0.9	(1.07)/Bbl	(1.0)	0.7	(4.01)/Bbl	(2.9)
Non-Hedge Accounting (2)			2.6			(4.8)			(0.3)
Ineffectiveness (3)			0.9			0.1			0.1
			$ 84.2			$ (8.0)			$ 21.4

(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 APL that do not qualify for hedge accounting.

As part of the Atlas mergers, outstanding APL derivative contracts with a fair value of $102.1 million as of the acquisition date were novated to the Partnership and included in the acquisition date fair value of assets acquired. Derivative settlements of $67.9 million related to these novated contracts were received during the year ended December 31, 2015 and were reflected as a reduction of the acquisition date fair value of the APL derivative assets acquired, with no effect on results of operations.

Liquidity and Capital Resources

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

Our main sources of liquidity and capital resources are internally generated cash flow from operations, borrowings under the TRP Revolver, borrowings under the Securitization Facility, the issuance of additional Preferred Units and access to public equity and private capital and debt markets. The capital markets continue to experience volatility. Our exposure to current credit conditions includes our credit facility, cash investments and counterparty performance risks. We continually monitor our liquidity and the credit markets, as well as events and circumstances surrounding each of the lenders to the TRP Revolver and Securitization Facility.

Our liquidity as of January 31, 2016 was:

		January 31, 2016
		(In millions)
Cash on hand		$ 154.7
Total commitments under the TRP Revolver		1,600.0
Total availability under the Securitization Facility		225.0
		1,979.7
Less:	Outstanding borrowings under the TRP Revolver	(380.0)
	Outstanding borrowings under the Securitization Facility	(225.0)
	Outstanding letters of credit under the TRP Revolver	(13.0)
	Total liquidity	$ 1,361.7

Other potential capital resources include:

- our right to request an additional $300 million in commitment increases under the TRP Revolver, subject to the terms therein. The TRP Revolver matures on October 3, 2017.

A portion of our capital resources may be 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 offset by plant settlements payable to producers. The factors that typically cause overall variability in our reported total working capital are: (1) our cash position; (2) liquids inventory levels and valuation, which we closely manage; (3) changes in the fair value of the current portion of derivative contracts; and (4) major structural changes in our asset base or business operations, such as acquisitions or divestitures and certain organic growth projects.

Our working capital increased $21.7 million excluding the increase in current debt obligations. The major items contributing to this increase were increased cash balances, an increase in our net risk management working capital asset position due to changes in the forward prices of commodities, and decreased payables to Parent due to lower compensation and related costs. Partially offsetting these items were an increase in interest accruals related to new borrowings, decreased commodity activity and inventories due to falling prices, and increased accruals for other goods and services.

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

Cash Flow

Cash Flow from Operating Activities

2015	2014	2013	2015 vs. 2014	2014 vs. 2013
		(In millions)		
$ 1,083.9	$ 838.5	$ 411.4	$ 245.4	$ 427.1

Our Consolidated Statements of Cash Flows included in our historical consolidated financial statements employs the traditional indirect method of presenting cash flows from operating activities. Under the indirect method, net cash provided by operating activities is derived by adjusting our net income for non-cash items related to operating activities. An alternative GAAP presentation employs the direct method in which the actual cash receipts and outlays comprising cash flow are presented.

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

	2015	2014	2013	2015 vs. 2014	2014 vs. 2013
			(In millions)		
Cash flows from operating activities:					
Cash received from customers	$ 6,820.9	$ 8,769.5	$ 6,388.3	$ (1,948.6)	$ 2,381.2
Cash received from (paid to) derivative counterparties	140.5	(4.9)	20.9	145.4	(25.8)
Cash outlays for:					
Product purchases	5,058.8	7,268.5	5,364.8	(2,209.7)	1,903.7
Operating expenses	448.9	402.5	377.3	46.4	25.2
General and administrative expenses	175.2	133.7	145.3	41.5	(11.6)
Cash distributions from equity investments (1)	(13.8)	(18.0)	(12.0)	4.2	(6.0)
Interest paid, net of amounts capitalized (2)	193.1	131.0	119.1	62.1	11.9
Income taxes paid, net of refunds	3.4	2.7	2.3	0.7	0.4
Other cash (receipts) payments	11.9	5.7	1.0	(2)	4.7
Net cash provided by operating activities	$ 1,083.9	$ 838.5	$ 411.4	$ 245.4	$ 427.1

(1) Excludes $1.2 million and $5.7 million included in investing activities for 2015 related to distributions from GCF and T2 Joint Ventures that exceeded cumulative equity earnings for 2015 and 2014. GCF did not have distributions that exceeded cumulative earnings for 2013.
(2) Net of capitalized interest paid of $13.2 million, $16.1 million and $28.0 million included in investing activities for 2015, 2014, and 2013.

Lower commodity prices were the primary contributor to decreased cash collections and payments for product purchases in 2015 compared to 2014. Derivatives were a net inflow in 2015 versus a net outflow in 2014 reflecting lower commodity prices paid to counterparties compared to the fixed price we received on those derivative contracts. Higher cash outlay for general and administrative expenses in 2015 versus 2014 was mainly due to the addition of general and administrative costs for TPL. Higher cash interest paid was primarily due to higher debt borrowings. Other cash payments during 2015 reflect transaction costs related to the Atlas mergers.

Higher natural gas prices, sales and logistics fees related to export activities and higher NGL production volumes contributed to increased cash collections in 2014 compared to 2013, as well as higher cash payments to producers for commodity products. The change in cash received related to derivatives reflects higher commodity prices paid to counterparties compared to the fixed price we received on those derivative contracts. Lower cash general and administrative expenses in 2014 versus 2013 were mainly due to the lower cash settlements on TRC long term incentive plan costs allocated to us. The increase in other cash payments during 2014 reflects transaction costs incurred in advance of the Atlas mergers.

Cash Flow from Investing Activities

2015	2014	2013	2015 vs. 2014	2014 vs. 2013
		(In millions)		
$ (1,653.9)	$ (751.4)	$ (1,026.3)	$ (902.5)	$ 274.9

The increase in net cash used in investing activities for 2015 compared to 2014 was primarily due to the $828.7 million outlays for the cash portion of Atlas mergers, along with a $55.0 million increase in capital expenditures and an $11.7 million increase in investments in unconsolidated affiliates.

The decrease in net cash used in investing activities for 2014 compared to 2013 was primarily due to lower cash outlays for capital expansion projects of $251.4 million.

Cash Flow from Financing Activities

2015	2014	2013	2015 vs. 2014	2014 vs. 2013
		(In millions)		
$ 633.1	$ (72.3)	$ 604.4	$ 705.4	$ (676.7)

The increase in net cash provided by financing activities for 2015 compared to 2014 was primarily due to increased net borrowings under our debt facilities ($1,954.0 million) offset by payment to settle the tender for APL's senior notes ($1,168.8 million). The contribution from noncontrolling interests increased by $78.4 million due to the cash calls for capital expansion. Contribution from the General Partner and proceeds from equity offerings increased in 2015 ($83.3 million), offset by an increase in distributions to owners ($239.8 million).

The decrease in net cash provided by financing activities for 2014 compared to 2013 was primarily due to lower net borrowings under our debt facilities ($448.2 million), an increase in distributions to owners ($98.1 million), and a decrease in proceeds from equity offerings ($115.1 million).

Capital Requirements

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

	2015	2014	2013
Capital expenditures :		(In millions)	
Consideration for business acquisitions	$ 5,024.2	$ -	$ -
Non-cash consideration APL merger	(2,583.1)	-	-
Non-cash Targa contribution, Special General Partner interest (1)	(1,612.4)	-	-
Cash consideration for business acquisitions, net of cash acquired	828.7	-	-
Expansion	679.3	668.7	954.6
Maintenance	97.9	79.1	79.9
Gross capital expenditures	777.2	747.8	1,034.5
Transfers from materials and supplies inventory to property, plant and equipment	(3.8)	(4.6)	(20.5)
Decrease (increase) in capital project payables and accruals	43.8	19.0	(0.4)
Cash outlays for capital projects	817.2	762.2	1,013.6
Targa cash consideration, ATLS merger	745.6	-	
	$ 2,391.5	$ 762.2	$ 1,013.6

(1) Includes the Special GP Interest and non-cash value of consideration (see Note 4-Business Acquisitions of the "Consolidated Financial Statements").

We currently estimate that we will invest $525 million or less in growth capital expenditures for announced projects for 2016. Given our objective of growth through acquisitions, expansions of existing assets and other internal growth projects, we anticipate that over time we will invest significant amounts of capital to grow and acquire assets. Future expansion capital expenditures may vary significantly based on investment opportunities. We expect to fund future capital expenditures with funds generated from our operations, borrowings under the TRP Revolver and the Securitization Facility and proceeds from issuances of additional equity and debt securities. Major organic growth projects for 2016 are discussed in "Item1. Business-Organic Growth Projects."

Credit Facilities and Long-Term Debt

The following table summarizes our debt obligations as of December 31, 2015 (in millions):

Current:	
Accounts receivable securitization facility, due December 2016	$ 219.3
Long-term:	
Senior secured revolving credit facility, due October 2017	280.0
Senior unsecured notes, 5% fixed rate, due January 2018	1,100.0
Senior unsecured notes, 4⅛% fixed rate, due November 2019	800.0
Senior unsecured notes, 6⅝% fixed rate, due October 2020	342.1
Unamortized premium	5.0
Senior unsecured notes, 6⅞% fixed rate, due February 2021	483.6
Unamortized discount	(22.1)
Senior unsecured notes, 6⅜% fixed rate, due August 2022	300.0
Senior unsecured notes, 5¼% fixed rate, due May 2023	583.7
Senior unsecured notes, 4¼% fixed rate, due November 2023	623.5
Senior unsecured notes, 6¾% fixed rate, due March 2024	600.0
Senior unsecured APL notes, 6⅝% fixed rate, due October 2020	12.9
Unamortized premium	0.2
Senior unsecured APL notes, 4¾% fixed rate, due November 2021	6.5
Senior unsecured APL notes, 5⅞% fixed rate, due August 2023	48.1
Unamortized premium	0.5
Total long-term debt	5,164.0
Total debt	$ 5,383.3
Letters of credit outstanding	$ 12.9

See Note 9 – Debt Obligations to the “Consolidated Financial Statements” beginning on Page F-1 of this Annual Report for more information regarding our debt obligations.

Compliance with Debt Covenants

As of December 31, 2015, we were in compliance with the covenants contained in our various debt agreements.

Revolving Credit Agreement

In October 2012, we entered into a Second Amended and Restated Credit Agreement that amended and replaced our variable rate Senior Secured Credit Facility due July 2015 to provide a variable rate Senior Secured Credit Facility due October 3, 2017 (the “Original Agreement”). The Original Agreement had an available commitment of $1.2 billion and allowed us to request up to an additional $300.0 million in commitment increases.

In February 2015, we entered into the First Amendment, Waiver and Incremental Commitment Agreement (the “First Amendment”) that amended the Original Agreement. The First Amendment increased available commitments to $1.6 billion from $1.2 billion while retaining our ability to request up to an additional $300.0 million in commitment increases. In addition, the First Amendment amended certain provisions of the existing TRP Revolver and designates each of TPL and its subsidiaries as an “Unrestricted Subsidiary.” We used proceeds from borrowings under the credit facility 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 our option, either at the base rate or the Eurodollar rate. The base rate is equal to the highest of: (i) Bank of America’s prime rate; (ii) the federal funds rate plus 0.5%; or (iii) the one-month LIBOR rate plus 1.0%, plus an applicable margin ranging from 0.75% to 1.75% (dependent on our 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 our ratio of consolidated funded indebtedness to consolidated adjusted EBITDA).

We are required to pay a commitment fee equal to an applicable rate ranging from 0.3% to 0.5% (dependent on our 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 our ratio of consolidated funded indebtedness to consolidated adjusted EBITDA).

The TRP Revolver is collateralized by a majority of our assets and the assets of our restricted subsidiaries. Borrowings are guaranteed by our restricted subsidiaries.

The TRP Revolver restricts our ability to make distributions of available cash to unitholders if a default or an event of default (as defined in the TRP Revolver) exists or would result from such distribution. The TRP Revolver requires us to maintain a ratio of consolidated funded indebtedness to consolidated adjusted EBITDA of no more than 5.50 to 1.00 and also requires us to maintain a ratio of consolidated 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, our ability to incur indebtedness, grant liens, make investments, repay or amend the terms of certain other indebtedness, merge or consolidate, sell assets, and engage in transactions with affiliates (in each case, subject to our right to incur indebtedness or grant liens in connection with, and convey accounts receivable as part of, a permitted receivables financing).

Senior Unsecured Notes

In May 2013, we privately placed $625.0 million in aggregate principal amount of 4¼% Notes. The 4¼% Notes resulted in approximately $618.1 million of net proceeds, which were used to reduce borrowings under the TRP Revolver and for general partnership purposes.

In June 2013, we paid $106.4 million plus accrued interest, which included a premium of $6.4 million, to redeem $100.0 million of the outstanding 6⅜% Notes. The redemption resulted in a $7.4 million loss on debt redemption, including the write-off of $1.0 million of unamortized debt issuance costs.

In July 2013, we paid $76.8 million plus accrued interest, which included a premium of $4.1 million, per the terms of the note agreement to redeem the outstanding balance of the 11¼% Notes. The redemption resulted in a $7.4 million loss on debt redemption in the third quarter 2013, including the write-off of $1.0 million of unamortized debt issuance costs.

In October 2014, we privately placed $800.0 million in aggregate principal amount of 4⅛% Senior Notes due 2019 (the “4⅛% Notes”). The 4⅛% Notes resulted in approximately $790.8 million of net proceeds, which were used to reduce borrowings under the TRP Revolver and Securitization Facility and for general partnership purposes.

In November 2014, we redeemed the outstanding 7⅞% Notes at a price of 103.938% plus accrued interest through the redemption date. The redemption resulted in a $12.4 million loss on redemption for the year ended 2014, consisting of premiums paid of $9.9 million and a non-cash loss to write-off $2.5 million of unamortized debt issuance costs.

In January 2015, we and Targa Resources Partners Finance Corporation (collectively, the “Partnership Issuers”) issued $1.1 billion in aggregate principal amount of 5% Notes resulting in approximately $1,089.8 million of net proceeds after costs, which were used together with borrowings from the TRP Revolver, to fund the APL Notes Tender Offers and the Change of Control Offer.

In September 2015, the Partnership Issuers issued $600.0 million in aggregate principal amount of 6¾% Notes resulting 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% Notes are unsecured senior obligations that have substantially the same terms and covenants as our other senior notes.

Debt Repurchases

In December 2015, we repurchased on the open market a portion of various series of our outstanding senior notes paying $14.3 million plus accrued interest to repurchase $17.9 million of the outstanding balances. The December 2015 note repurchases resulted in a $3.6 million gain on debt repurchase and a write-off of $0.1 million in related deferred debt issuance costs.

We may retire or purchase various series of our outstanding debt through cash purchases and/or exchanges for other debt, in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

APL Merger Financing Activities

APL Senior Notes Tender Offers

In January 2015, we commenced cash tender offers for any and all of the outstanding fixed rate senior secured notes to be acquired in the APL merger, referred to as the APL Notes Tender Offers, which totaled $1.55 billion.

The results of the APL Notes Tender Offers were:

Senior Notes	Outstanding Note Balance	Amount Tendered	Premium Paid	Accrued Interest Paid	Total Tender Offer payments	% Tendered	Note Balance after Tender Offers
			($ amounts in millions)				
6⅝% due 2020	$ 500.0	$ 140.1	$ 2.1	$ 3.7	$ 145.9	28.02%	$ 359.9
4¾% due 2021	400.0	393.5	5.9	5.3	404.7	98.38%	6.5
5⅞% due 2023	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 APL Notes Tender Offers, on February 27, 2015, the supplemental indentures governing the 2021 APL Notes and the 2023 APL Notes of the APL Issuers, became operative. These supplemental indentures eliminated substantially all of the restrictive covenants and certain events of default applicable to the 2021 APL Notes and the 2023 APL Notes that were not accepted for payment.

Not having achieved the minimum tender condition on the 2020 APL Notes, we made a change of control offer, referred to as the Change of Control Offer, for any and all of the 2020 APL 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 APL 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 APL Notes Tender Offers and Change of Control Offer totaling $1,168.8 million are presented as financing activities in the 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 APL 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, we had received tenders and consents from holders of approximately 96.3% of the total outstanding 2020 APL 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 APL 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 APL 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. We recognized $0.7 million of costs associated with the Exchange Offer, reflected as a Loss from financing activities on our Consolidated Statements of Operations.

Selected terms of the senior unsecured notes outstanding as of December 31, 2015 are as follows:

Note Issue	Issue Date	Per Annum Interest Rate	Due Date	Dates Interest Paid
"6⅞% Notes"	February 2011	6⅞%	February 1, 2021	February & August 1st
"6⅜% Notes"	January 2012	6⅜%	August 1, 2022	February & August 1st
"5¼% Notes"	Oct / Dec 2012	5¼%	May 1, 2023	May & November 1st
"4¼% Notes"	May 2013	4¼%	November 15, 2023	May & November 15th
"4⅛% Notes"	October 2014	4⅛%	November 15, 2019	May & November 15th
"5% Notes"	January 2015	5%	January 15, 2018	January & July 15th
"6⅝% Notes"	May 2015	6⅝%	October 1, 2020	February & October 1st
"6¾% Notes"	September 2015	6¾%	March 15, 2024	March & September 15th
"APL 6⅝% Notes"	Sept 2012 (1)	6⅝%	October 1, 2020	April & October 1st
"APL 4¾% Notes"	May 2013 (1)	4¾%	November 15, 2021	May & November 15th
"APL 5⅞% Notes"	February 2013 (1)	5⅞%	August 1, 2023	February & August 1st

(1) Issue dates for APL Notes are original dates of issuance. These notes were acquired in the APL Merger. See Note 4 – Business Acquisitions.

All issues of unsecured senior notes are obligations that rank pari passu in right of payment 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 us. These notes are effectively subordinated to all secured indebtedness under the TRP Revolver, which is secured by a majority of our assets and our Securitization Facility, which is secured by accounts receivable pledged under it, to the extent of the value of the collateral securing that indebtedness. Interest on all issues of senior unsecured notes is payable semi-annually in arrears.

Our senior unsecured notes and associated indenture agreements restrict our ability to make distributions to unitholders in the event of default (as defined in the indentures). The indentures also restrict our ability and the ability of certain of our subsidiaries to: (i) incur additional debt or enter into sale and leaseback transactions; (ii) pay certain distributions on or repurchase equity interests (only if such distributions do not meet specified conditions); (iii) make certain investments; (iv) incur liens; (v) enter into transactions with affiliates; (vi) merge or consolidate with another company; and (vii) transfer and sell assets. These covenants are subject to a number of important exceptions and qualifications. If at any time when the notes are rated investment grade by Moody's and S&P (or rated investment grade by Moody's and S&P for the 6⅞ Notes) 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 we will cease to be subject to such covenants.

Accounts Receivable Securitization Facility

The Securitization Facility provides up to $225.0 million of borrowing capacity at LIBOR market index rates plus a margin through December 9, 2016. Under the Securitization Facility, TMS contributes receivables to TGM, and TGM and TLMT sell or contribute receivables, without recourse, to TRLLC. TRLLC, in turn, sells an undivided percentage ownership in the eligible receivables to a third-party financial institution. Receivables up to the amount of the outstanding debt under the Securitization Facility are not available to satisfy the claims of the creditors of TLMT, TMS, TGM or us. Any excess receivables are eligible to satisfy the claims of creditors of TLMT, TMS, TGM or us. As of December 31, 2015, total funding under the Securitization Facility was $219.3 million.

Off-Balance Sheet Arrangements

As of December 31, 2015, there were $24.5 million in surety bonds outstanding related to various performance obligations. These are in place to support various performance obligations as required by (i) statutes within the regulatory jurisdictions where we operate, (ii) surety, and (iii) counterparty support. Obligations under these surety bonds are not normally called, as we typically comply with the underlying performance requirement.

Contractual Obligations

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

	Payments Due By Period				
Contractual Obligations:	**Total**	**Less Than 1 Year**	**1-3 Years**	**3-5 Years**	**More Than 5 Years**
	(In millions, except volumetric information)				
Debt obligations (1)	$ 5,180.4	$ -	$ 1,380.0	$ 1,155.0	$ 2,645.4
Interest on debt obligations (2)	1,554.4	280.3	548.2	385.0	340.9
Operating leases (3)	45.2	16.0	19.6	6.5	3.1
Land site lease and right-of-way (4)	11.0	2.4	4.5	4.1	-
Purchase Obligations: (5)					
Pipeline capacity and throughput agreements (6)	474.7	88.9	131.8	101.9	152.1
Commodities (7)	61.2	61.2	-	-	-
Purchase commitments and service contract (8)	202.9	191.4	8.6	2.9	-
	$ 7,529.8	$ 640.2	$ 2,092.7	$ 1,655.4	$ 3,141.5
Commodity Volumetric Commitments:					
Natural Gas (MMBtu)	24.8	24.8	-	-	-
NGL and petroleum products (millions of gallons)	16.6	16.6	-	-	-

(1) Represents scheduled future maturities of consolidated debt obligations for the periods indicated.
(2) Represents interest expense on debt obligations based on both fixed debt interest rates and prevailing December 31, 2015 rates for floating debt.
(3) Includes minimum payments on lease obligations for office space, railcars and tractors.
(4) Land site lease and right-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.
(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, 2015.
(8) Includes commitments for capital expenditures, operating expenses and service contracts.

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with GAAP requires our management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from these estimates. The 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.

Property, Plant and Equipment and Intangibles

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 on a straight-line basis, or where more appropriate, in a manner that closely resembles the expected pattern in which we benefit from services provided to customers. At the time we place our assets in service, 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 forecast life of applicable resources basins.

We evaluate long-lived assets, including related intangibles, of identifiable business activities for impairment when events or changes in circumstances indicate, in management's judgment, that the carrying value of such assets may not be recoverable. As a result of this evaluation, the carrying value of certain Louisiana gas processing facilities and associated gathering systems in the Coastal Gathering and Processing segment was reduced by $32.6 million and $3.2 million during the years ended December 31, 2015 and 2014 as a result of reduced forecasted gas processing volumes due to market conditions and processing spreads. These carrying value adjustments are included in depreciation and amortization expenses on our Consolidated Statements of Operations. There have been no other significant changes impacting long-lived assets.

Goodwill

Goodwill results when the cost of an acquisition exceeds the fair value of the net identifiable assets of the acquired business. We evaluate goodwill for impairment at least annually, as of November 30th, 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.

Our evaluation as of November 30, 2015 utilized the income approach (a discounted cash flow analysis ("DCF")) to estimate the fair values of our reporting units. The future cash flows for our reporting units were based on our estimates, at that time, of future revenues, income from operations and other factors, such as working capital and capital expenditures. We took into account current and expected industry and market conditions, commodity pricing and volumetric forecasts 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.

Based on the results of our evaluation, we have recorded a provisional goodwill impairment of $290.0 million during the year ended December 31, 2015 and reduced the carrying value of goodwill to $417.1 million as of December 31, 2015.

Revenue Recognition

Our operating revenues are primarily derived from the following activities:

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

Price Risk Management (Hedging)

Our net income and cash flows are subject to volatility stemming from changes in commodity prices and interest rates. To reduce the volatility of our cash flows, we have entered into derivative financial instruments related to a portion of our equity volumes to manage the purchase and sales prices of commodities. We are exposed to the credit risk of certain of our counterparties in these derivative financial instruments. Our futures contracts have limited credit risk since they are cleared through an exchange and are settled daily. We also monitor NGL inventory levels with a view to mitigating losses related to downward price exposure.

Our cash flow is affected by the derivative financial instruments we enter into to the extent these instruments are settled by (i) making or receiving a payment to/from the counterparty or (ii) making or receiving a payment for entering into a contract that exactly offsets the original derivative financial instrument. Typically a derivative financial instrument is settled when the physical transaction that underlies the derivative financial instrument occurs.

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 in the balance sheet. The relationship between the derivative financial instruments 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 derivative financial instrument and on an ongoing basis. Hedge accounting is discontinued prospectively when a derivative financial instrument becomes ineffective. Gains and losses deferred in other comprehensive income ("OCI") related to cash flow hedges for which hedge accounting has been discontinued remain deferred until the forecasted transaction occurs. If it is probable that a hedged forecasted transaction will not occur, deferred gains or losses on the derivative financial instrument are reclassified to earnings immediately.

The estimated fair value of our derivative financial instruments was a net asset of $119.5 million as of December 31, 2015, net of an adjustment for credit risk. The credit risk adjustment is based on the default probabilities by year as indicated by the counterparties' credit default swap transactions. These default probabilities have been applied to the unadjusted fair values of the derivative financial instruments to arrive at the credit risk adjustment, which is immaterial for all periods covered by this Annual Report. We have an active credit management process which is focused on controlling loss exposure to bankruptcies or other liquidity issues of counterparties.

Use of Estimates

When preparing financial statements in conformity with GAAP, management must make estimates and assumptions based on information available at the time. These estimates and assumptions affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosures of contingent assets and liabilities as of the date of the financial statements. 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 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) valuing mandatorily redeemable preferred interests. Actual results, therefore, could differ materially from estimated amounts.

Recent Accounting Pronouncements

For a discussion of recent accounting pronouncements that will affect us, see "Recent Accounting Pronouncements" included under Note 3 – Significant Accounting Policies of 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 of 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 operation. 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 through 2018. The current market conditions may also impact our ability to enter into future commodity derivative contracts.

Commodity Price Risk

A significant portion of our revenues is 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 and NGLs are subject to fluctuations in response to changes in supply, demand, market uncertainty and a variety of additional factors beyond our control. We monitor these risks and enter into hedging transactions designed to mitigate the impact of commodity price fluctuations on our business. Cash flows from a derivative instrument designated as a hedge are classified in the same category as the cash flows from the item being hedged.

The primary purpose of our commodity risk management activities is to hedge some of the exposure to commodity price risk and reduce volatility in our operating cash flows due to fluctuations in commodity prices. In an effort to reduce the variability of our cash flows, as of December 31, 2015, we have hedged the commodity price associated with a portion of our expected (i) natural gas equity volumes in Field Gathering and Processing Operations and (ii) NGL and condensate equity volumes predominately in Field Gathering and Processing Operations, as well as in the LOU portion of the Coastal Gathering and Processing Operations, that result from percent-of-proceeds processing arrangements by entering into derivative instruments. We hedge a higher percentage of our expected equity volumes in the current year compared to future years, in which we hedge incrementally lower percentages of expected equity volumes. With swaps and futures, 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 and futures 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, futures, collars, purchased puts (or floors) 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.

These commodity price-hedging transactions are typically documented pursuant to a standard International Swap Dealers Association form with customized credit and legal terms. Our 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 natural gas and NGL prices relative to the fixed prices set forth in the hedges are secured by a first priority lien in the collateral securing our senior secured indebtedness that ranks equal in right of payment with liens granted in favor of our senior secured lenders. Absent federal regulations resulting from the Dodd-Frank Act, and as long as this first priority lien is in effect, we expect to have no obligation to post cash, letters of credit or other additional collateral to secure these hedges at any time, even if our 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.

For all periods presented, we have entered into hedging arrangements for a portion of our forecasted equity volumes. During the year ended December 31, 2015, 2014 and 2013 our operating revenues increased (decreased) by net hedge adjustments on commodity derivative contracts of $84.2 million, ($8.0) million and $21.4 million.

We also enter into derivative instruments to help manage other short-term commodity-related business risks. We have not designated these derivatives as hedges and record changes in fair value and cash settlements to revenues.

Our risk management position has moved from a net asset position of $55.0 million at December 31, 2014 to a net asset position of $119.5 million at December 31, 2015. The fixed prices we currently expect to receive on derivative contracts are above the aggregate forward prices for commodities related to those contracts, creating this net asset position. We account for derivatives that mitigate commodity price risk as cash flow hedges. Changes in fair value are deferred in OCI until the underlying hedged transactions settle.

As of December 31, 2015, we had the following derivative instruments designated as hedging instruments that will settle during the years ending below:

Natural Gas

Instrument Type	Index	Price $/MMBtu		2016	2017	2018	Fair Value (In millions)
Swap	IF-WAHA	3.94		19,436	-	-	$ 7.5
Swap	IF-WAHA	3.69		-	5,000	-	1.8
Total Swaps				19,436	5,000	-	
Swap	IF-PB	3.99		7,608	-	-	4.6
Total Swaps				7,608	-	-	
Swap	IF-NGPL MC	3.93		3,456	-	-	2.0
Total Swaps				3,456	-	-	-
Swap	NG-NYMEX	4.16		37,592	-	-	23.2
Swap	NG-NYMEX	4.11		-	18,082	-	8.5
Total Swaps				37,592	18,082	-	
Total Natural Gas Swaps				68,092	23,082	-	
							47.6
		Put Price	**Call Price**				
Collar	IF-WAHA	2.85	3.47	7,500	-	-	1.5
Collar	IF-WAHA	3.00	3.67	-	7,500	-	1.2
Collar	IF-WAHA	3.25	4.20	-	-	1,849	0.3
Total Collars				7,500	7,500	1,849	
Collar	IF-PB	2.65	3.31	15,400	-	-	2.2
Collar	IF-PB	2.80	3.50	-	15,400	-	1.7
Collar	IF-PB	3.00	3.65	-	-	7,637	0.9
Total Collars				15,400	15,400	7,637	
Total Natural Gas Collars				22,900	22,900	9,486	
							$ 55.4

NGL

Instrument Type	Index	Price $/Gal		2016	2017	2018	Fair Value (In millions)
Swap	C2 OPIS-MB	0.21		420	-	-	$ 0.3
Swap	C2 OPIS-MB	0.23		-	420	-	0.2
Swap	C2 OPIS-MB	0.26		-	-	208	0.1
Total Swaps				420	420	208	
Swap	C3 OPIS-MB	0.78		4,053	-	-	23.1
Swap	C3 OPIS-MB	1.04		-	658	-	6.1
Total Swaps				4,053	658	-	
Total NGL Swaps				4,473	1,078	208	
Futures	C2 OPIS-MB	0.18		806	-	-	-
Futures	C3 OPIS-MB	0.40		863	-	-	(0.2)
Futures	IC4 OPIS-MB	0.56		287	-	-	(0.1)
Total NGL Futures				1,956	-	-	
		Put Price	**Call Price**				
Collar	C2 OPIS-MB	0.200	0.235	410	-	-	0.2
Collar	C2 OPIS-MB	0.240	0.290	-	410	-	0.3
				410	410	-	
		Put Price	**Call Price**				
Collar	C3 OPIS-MB	0.560	0.680	380	-	-	0.9
Collar	C3 OPIS-MB	0.570	0.686	-	380	-	1.0
				380	380	-	
		Put Price	**Call Price**				
Collar	C5 OPIS-MB	1.200	1.390	130	-	-	0.6
Collar	C5 OPIS-MB	1.210	1.415	-	130	-	0.6
Collar	C5 OPIS-MB	1.230	1.385	-	-	32	0.2
				130	130	32	
Total Collars				920	920	32	
Total NGL				7,349	1,998	240	
							$ 33.3

Condensate

Instrument Type	Index	Price $/Bbl		2016	2017	2018	Fair Value
							(In millions)
Swap	NY-WTI	72.90		1,502	-	-	$ 17.3
Swap	NY-WTI	79.70		-	500	-	5.9
Total Swaps				1,502	500	-	
		Put Price	Call Price				
Collar	NY-WTI	57.08	67.97	790	-	-	4.7
Collar	NY-WTI	58.56	69.95	-	790	-	3.8
Collar	NY-WTI	60.00	71.60	-	-	101	0.5
Total Collars				790	790	101	
Total				2,292	1,290	101	
							$ 32.2

As of December 31, 2015 we had the following derivative instruments that are not designated as hedges and are marked-to-market:

Natural Gas

Instrument Type	Index	Price $/MMBtu	2016	2017	2018	Fair Value
						(In millions)
Swap	IF-WAHA	2.86	15,172	-	-	$ -
Basis Swap	various	(0.21)	48,962	18,082	-	(1.4)
						$ (1.4)

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 futures contracts executed through a counterparty that clears the hedges through an exchange, the classification of these instruments is Level 1 within the fair value hierarchy. 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 swap and options, the valuations are classified as Level 3 within the fair value hierarchy. See Note 14 of the "Consolidated Financial Statements" in this Quarterly Report for more information regarding classifications within the fair value hierarchy.

Interest Rate Risk

We are exposed to the risk of changes in interest rates, primarily as a result of variable rate borrowings under the TRP Revolver and the Securitization Facility. As of December 31, 2015, we do not have any interest rate hedges. However, we may in the future enter into interest rate hedges intended to mitigate the impact of changes in interest rates on cash flows. To the extent that interest rates increase, interest expense for the TRP Revolver and the Securitization Facility will also increase. As of December 31, 2015, we had $499.3 million in outstanding variable rate borrowings under the TRP Revolver and the Securitization Facility. A hypothetical change of 100 basis points in the interest rate of our variable debt would impact our annual interest expense by $5.0 million.

Counterparty Credit Risk

We are subject to risk of losses resulting from nonpayment or nonperformance by certain of 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 settled 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 of 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 $7.6 million as of December 31, 2015. The range of losses attributable to our individual counterparties would be between less than $0.4 million and $38.9 million, depending on the counterparty in default.

Customer Credit Risk

We extend credit to customers and other parties in the normal course of business. We have an established policy and various procedures to manage our credit exposure risk, including initial and subsequent credit risk analyses, credit limits and terms and credit enhancements when necessary. We use credit enhancements including (but not limited to) letters of credit, prepayments, parental guarantees and rights of offset to limit credit risk to ensure that our established credit criteria are followed and financial loss is mitigated or minimized.

We have an active credit management process, which is focused on controlling loss exposure to bankruptcies or other liquidity issues of counterparties. If an assessment of uncollectible accounts resulted in a 1% reduction of our third-party accounts receivable, annual operating income would decrease by $5.1 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, 2015, our disclosure controls and procedures were not effective at the reasonable assurance level to provide 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 principal executive officer and principal financial officer, as appropriate, to allow for timely decisions regarding required disclosure because of the material weakness in our internal control over financial reporting as discussed below.

Internal Control Over Financial Reporting

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

Management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Management conducted an evaluation of the effectiveness of the internal control over financial reporting based on "Internal Control — Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013. Based on the results of this evaluation, management concluded that the internal control over financial reporting was not effective as of December 31, 2015, because of the material weakness described below and in Management's Report on Internal Control included on page F-2 in this Annual Report, which is incorporated herein by reference.

A "material weakness" is a deficiency, or combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis.

We did not maintain effective controls over the valuation of certain assets in the Atlas mergers. Specifically, our review procedures over the development and application of inputs, assumptions, and calculations used in cash flow-based fair value measurements associated with business combinations did not operate as designed and at an appropriate level of detail commensurate with our financial reporting requirements. This control deficiency resulted in immaterial errors in our financial statements for the three and nine months ended September 30, 2015, the three and six months ended June 30, 2015 and the three months ended March 31, 2015 including reclassification of property, plant and equipment, intangible assets, goodwill and noncontrolling interest in the balance sheets and a reduction of depreciation and amortization expense. These errors were determined not to be material to the consolidated financial statements. However, this control deficiency result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected. Accordingly, our management has determined that this control deficiency represents a material weakness.

The businesses of Atlas Pipeline Partners, L.P. which the Partnership purchased on February 27, 2015 and Atlas Energy, L.P. which Targa purchased on February 27, 2015 were excluded from the scope of our management's assessment of our internal control over financial reporting as of December 31, 2015. These businesses constituted 21.6% and 18.0% of total reportable segment revenue and operating margin for the year ended December 31, 2015 and 51.5% of total assets at December 31, 2015.

The effectiveness of our internal control over financial reporting as of December 31, 2015 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears on page F-3.

(b) Remediation Plans

We are currently working towards remediating the material weakness in our internal control over financial reporting and are implementing additional processes designed to address the underlying causes of the material weakness. We have implemented formal processes to address the accounting and disclosures related to business acquisitions. These processes are also related directly to goodwill impairment reviews. We have not completed any acquisitions since the identification of the material weakness. While neither we nor our external auditors have tested the operating effectiveness of these new processes, they will be tested when we perform our annual goodwill impairment analysis for the 2016 reporting year or earlier should an interim impairment assessment become necessary.

(c) Changes in Internal Control Over Financial Reporting

During the three months ended December 31, 2015, the remediation efforts described in Remediation Plans above were changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information.

Partnership Tax Matters

On May 19, 2014, Targa Resources GP LLC received a Notice of Beginning of Administrative Proceeding ("NBAP") relating to the Internal Revenue Service's ("IRS") audit of TRP's 2011 Form 1065 federal tax return. Under IRS regulations, Targa was required to communicate the NBAP to all limited partners who hold less than 1% of our outstanding units ("Non-Notice Partners") within 75 days of receipt of the NBAP. To provide the NBAP to its Non-Notice Partners, Targa Resources GP LLC has posted the NBAP on its website under Tax Matters.

On April 9, 2015, Targa received a No Adjustments Letter relating to the IRS audit of TRP's 2011 Form 1065 federal tax return. There were no adjustments proposed by the IRS for TRP's 2011 Form 1065 federal tax return.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

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

Management of Targa Resources Partners LP

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

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

The Board has a standing audit committee (the “Audit Committee”) that consists of three directors. Messrs. Barry R. Pearl and Robert B. Evans, and Ms. Ruth I. Dreessen serve as the members of the Audit Committee. The Board has affirmatively determined that Messrs. Pearl and Evans and Ms. Dreessen are independent as described in the rules of the NYSE and the Exchange Act. The Board has also determined that, based upon relevant experience, Mr. Pearl is an “audit committee financial expert” as defined in Item 407 of Regulation S-K of the Exchange Act. Mr. Pearl serves as the Chairman of the Audit Committee. The Audit Committee assists the Board in its oversight of the integrity of our financial statements and our compliance with legal and regulatory requirements and partnership policies and controls. The Audit Committee has sole authority to retain and terminate our independent registered public accounting firm, approve all auditing services and related fees and the terms thereof and pre-approve any non-audit services to be rendered by our independent registered public accounting firm. The Audit Committee is also responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm has been given unrestricted access to the Audit Committee.

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

The Board has a standing conflicts committee (the “Conflicts Committee”) to review specific matters that the Board believes may involve conflicts of interest. Messrs. Evans and Pearl and Ms. Dreessen serve as the members of the Conflicts Committee. Mr. Evans serves as the Chairman of the Conflicts Committee. The Conflicts Committee determines if the resolution of the conflict of interest is fair and reasonable to us. The members of the Conflicts Committee may not be officers or employees of our general partner or directors, officers or employees of its affiliates and must meet the independence and experience standards established by the NYSE and the Exchange Act to serve on an audit committee of a board of directors and certain other requirements. Any matters approved by the Conflicts Committee in good faith will be conclusively deemed to be fair and reasonable to us, approved by all of our partners and not a breach by our general partner of any duties it may owe us or our unitholders.

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

Directors, Executive Officers and Other Officers

Our general partner's directors hold office until the earlier of their death, resignation, removal or disqualification or until their successors have been elected and qualified. Officers serve at the discretion of the Board. There are no family relationships among any of our general partner's directors or executive officers. The following table shows information with respect to the current directors, executive officers and other officers of Targa Resources GP LLC as of February 18, 2016:

Name	Age	Position With Targa Resources GP LLC
Joe Bob Perkins	55	Chief Executive Officer and Director
James W. Whalen	74	Executive Chairman of the Board and Director
Michael A. Heim	67	Vice Chairman of the Board and Director
Jeffrey J. McParland	61	President-Finance and Administration
Paul W. Chung	55	Executive Vice President, General Counsel and Secretary
Matthew J. Meloy	38	Executive Vice President and Chief Financial Officer
John R. Sparger	62	Senior Vice President and Chief Accounting Officer
D. Scott Pryor	53	Executive Vice President – Logistics and Marketing
Patrick J. McDonie	55	Executive Vice President – Southern Field Gathering and Processing
Dan C. Middlebrooks	59	Executive Vice President – Northern Field Gathering and Processing
Clark White	56	Executive Vice President – Engineering and Operations
Rene R. Joyce	68	Director
Robert B. Evans	66	Director
Barry R. Pearl	66	Director
Ruth I. Dreessen	59	Director

Joe Bob Perkins has served as Chief Executive Officer and director of our general partner, Targa and TRI Resources Inc. ("TRI") since January 1, 2012. Mr. Perkins previously served as President of Targa between the date of its formation on October 27, 2005 and December 31, 2011, of our general partner between October 2006 and December 31, 2011 and of TRI between February 2004 and December 31, 2011. He was a consultant for the TRI predecessor company during 2003. 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 Targa, 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 our general partner and Targa since January 1, 2015. Mr. Whalen has also served as a director of Targa since its formation on October 27, 2005, of our general partner since February 2007 and of TRI between 2004 and December 2010. Mr. Whalen previously served as Advisor to Chairman and CEO of our general partner, Targa and TRI between January 1, 2012 and December 31, 2014. He served as Executive Chairman of the Board of Targa and TRI between October 25, 2010 and December 31, 2011 and of our general partner between December 15, 2010 and December 31, 2011. He also served as President-Finance and Administration of Targa and TRI between January 2006 and October 2010 and our general partner between October 2006 and December 2010 and for various Targa subsidiaries since November 2005. Between October 2002 and October 2005, Mr. Whalen served as the Senior Vice President and Chief Financial Officer of Parker Drilling Company. Between January 2002 and October 2002, he was the Chief Financial Officer of Diversified Diagnostic Products, Inc. He served as Chief Commercial Officer of Coral 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 Partnership and industry address on a regular basis.

Michael A. Heim has served as Vice Chairman of the Board and director of our general partner since November 12, 2015. Mr. Heim previously served as President and Chief Operating Officer of our general partner, Targa and TRI between January 1, 2012 and November 12, 2015. Mr. Heim previously served as Executive Vice President and Chief Operating Officer of Targa between the date of its formation on October 27, 2005 and December 2011, of our general partner between October 2006 and December 2011 and of TRI between April 2004 and December 2011 and was a consultant for the TRI predecessor company 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 — Finance and Administration of our general partner since December 15, 2010 and of Targa and TRI since October 25, 2010. He has also served as a director of TRI since December 16, 2010. Mr. McParland served as Executive Vice President and Chief Financial Officer of Targa between October 27, 2005 and October 25, 2010 and of TRI between April 2004 and October 25, 2010 and was a consultant for the TRI predecessor company during 2003. He served as Executive Vice President and Chief Financial Officer of our general partner between October 2006 and December 15, 2010 and served as a director of our general partner from October 2006 to February 2007. Mr. McParland served as Treasurer of Targa from October 27, 2005 until May 2007, of our general partner from October 2006 until May 2007 and of TRI from April 2004 until May 2007. Mr. McParland served as Secretary of TRI between February 2004 and May 2004, at which time he was elected as Assistant Secretary. 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 our general partner since October 2006, Targa since its formation on October 27, 2005 and of TRI since May 2004. 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, 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 our general partner and Targa since May 2015 and of TRI since June 2015. He also served as Treasurer of our general partner and Targa until December 2015. Mr. Meloy previously served as Senior Vice President, Chief Financial Officer and Treasurer of our general partner since December 15, 2010 and of Targa and TRI since October 25, 2010. He also served as Vice President — Finance and Treasurer of Targa and TRI between April 2008 and October 2010, and as Director, Corporate Development of Targa and TRI between March 2006 and March 2008 and of our general partner between March 2006 and March 2008. He has served as Vice President — Finance and Treasurer of our general partner between April 2008 and December 15, 2010. Mr. Meloy was with The Royal Bank of Scotland in the structured finance group, focusing on the energy sector from October 2003 to March 2006, most recently serving as Assistant Vice President.

John R. Sparger has served as Senior Vice President and Chief Accounting Officer of our general partner since October 2006 and of Targa and TRI since January 2006. Mr. Sparger served as Vice President, Internal Audit of Targa between October 2005 and January 2006 and of TRI between November 2004 and January 2006. Mr. Sparger served as a consultant in the energy industry from 2002 through September 2004, including TRI between February 2004 and September 2004, providing advice to various energy companies and entities regarding processes, systems, accounting and internal controls. Prior to 2002, he worked in various accounting and administrative positions with companies in the energy industry, audit and consulting positions in public accounting and consulting positions with a large international consulting firm.

D. Scott Pryor, has served as Executive Vice President – Logistics and Marketing of our general partner and Targa since November 12, 2015. 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 our general partner and Targa since November 12, 2015. 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 our general partner and Targa 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 our general partner and Targa 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.

Rene R. Joyce has served as a director of our general partner since October 2006 and of Targa since its formation on October 27, 2005. Mr. Joyce previously served as Executive Chairman of the Board of our general partner Targa and TRI between January 1, 2012 and December 31, 2014. He also served as Chief Executive Officer of our general partner between October 2006 and December 31, 2011, Targa between October 27, 2005 and December 31, 2011 and TRI between February 2004 and December 31, 2011. He also served as director of TRI between 2004 and December 31, 2011 and was a consultant for the TRI predecessor company during 2003. 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 Oil Company ("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 TRI, 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.

Robert B. Evans has served as a director of our 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 us.

Barry R. Pearl has served as a director of our general partner since February 2007. Mr. Pearl is Executive Vice President of Kealine LLC (and its WesPac Midstream LLC affiliate), a private developer and operator of petroleum infrastructure facilities and is a director of Kayne Anderson Energy Development Company, Kayne Anderson/Midstream Energy Fund and Magellan Midstream Holdings, L.P., the general partner of Magellan Midstream Partners, L.P. Mr. Pearl served as President and Chief Executive Officer of TEPPCO Partners from May 2002 until December 2005 and as President and Chief Operating Officer from February 2001 through April 2002. Mr. Pearl served as Vice President of Finance and Chief Financial Officer of Maverick Tube Corporation from June 1998 until December 2000. From 1984 to 1998, Mr. Pearl was Vice President of Operations, Senior Vice President of business development and planning and Senior Vice President and Chief Financial Officer of Santa Fe Pacific Pipeline Partners, L.P. Mr. Pearl's board and executive experience across energy related companies including other MLPs enable him to make broad contributions to the issues and opportunities that we face. His industry, financial and executive experiences enable him to make valuable contributions to our general partner's audit and conflicts committees.

Ruth I. Dreessen has served as a director of our general partner since February 2013. Ms. Dreessen is a Managing Director of Lion Chemical Partners, LLC, (and its predecessors, Huntsman Lion and Lion Chemical Capital, LLC) where she has been employed since October 2010. Ms. Dreessen is also Chairman of Gevo, Inc. From 2010 to 2014, Ms Dreessen served as a director of Versar, Inc. Ms. Dreessen served as the Executive Vice President and Chief Financial Officer of TPC Group, Inc. from November 2005 to May 2010. Before joining TPC Group, she served as Senior Vice President, Chief Financial Officer and Director of Westlake Chemical Corp. from 2003 to 2005. Ms. Dreessen spent 21 years at JP Morgan Securities and predecessor companies ultimately as a Managing Director of chemicals investment banking, focused on leveraged and private equity transactions in chemicals and related industries. Ms. Dreessen's successful track record in investment banking with a focus in the chemical industry enhances the knowledge of the board in these areas. Her extensive experience as a financial executive brings financial and capital markets experience to the board.

Reimbursement of Expenses of Our General Partner

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

Corporate Governance

Code of Business Conduct and Ethics

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

Available Information

We make available, free of charge within the “Corporate Governance” section of our website at *http://www.targaresources.com* and in print to any unitholder who so requests, our Corporate Governance Guidelines, Code of Ethics, Code of Conduct and the Audit Committee Charter. Requests for print copies may be directed to: Investor Relations, Targa Resources Partners LP, 1000 Louisiana, Suite 4300, Houston, Texas 77002 or made by telephone by calling (713) 584-1000. The information contained on or connected to, our internet website is not incorporated by reference into this Annual Report and should not be considered part of this or any other report that we file with or furnish to the SEC.

Corporate Governance Guidelines

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

Executive Sessions of Non-Management Directors

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

Interested parties may communicate directly with our non-management directors by writing to: Non-Management Directors, Targa Resources Partners LP, 1000 Louisiana, Suite 4300, 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% unitholders 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 2014, 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

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

For 2015, our general partner's "named executive officers," identified in the Summary Compensation Table, were:

Name	Position During 2015
Joe Bob Perkins	Chief Executive Officer
Michael A. Heim (1)	Vice Chairman of the Targa Resources GP LLC Board
Jeffrey J. McParland	President—Finance and Administration
Paul W. Chung	Executive Vice President, General Counsel and Secretary
Matthew J. Meloy (2)	Executive Vice President and Chief Financial Officer

(1) On November 12, 2015, Mr. Heim was appointed as Vice Chairman of the board of directors of our general partner. In connection with his new role as Vice Chairman of the board of directors of our general partner, Mr. Heim resigned from his positions as President and Chief Operating Officer of our general partner and Targa. Mr. Heim continues to be an employee of Targa and a member of its executive management team and is expected to become a director and Vice Chairman of Targa following the close of the Buy-In Transaction.

(2) Mr. Meloy served as Senior Vice President, Chief Financial Officer and Treasurer of Targa and our general partner prior to his promotion to the Executive Vice President role in May 2015.

Our general partner's named executive officers also serve as executive officers of Targa, which is the parent of our general partner. The compensation information described in this CD&A and contained in the tables that follow reflects all compensation received by our general partner's named executive officers for the services they provide to us and for the services they provide to Targa and our general partner for the years covered. For further discussion of the compensation of our general partner's named executive officers following completion of the Buy-In Transaction and for 2016 generally, please see "—Changes for 2016."

For 2015, all decisions regarding named executive officer compensation were made by the compensation committee of Targa's board of directors (the "Compensation Committee"), except that long-term equity incentive awards recommended by the Compensation Committee under the Targa Resources Partners Long-Term Incentive Plan were approved by the board of directors of our general partner as administrator of that plan, which plan was assumed by Targa in connection with the Buy-In Transaction. The named executive officers devote their time as needed to the conduct of our business and affairs and the conduct of Targa and our general partner's business and affairs. During 2015, we reimbursed Targa and its affiliates for the compensation of our general partner's named executive officers pursuant to the Partnership Agreement. See "—Certain Relationships and Related Transactions, and Director Independence—Partnership Agreement" for additional information regarding our reimbursement obligations for 2015.

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

Targa held its last advisory say on pay vote regarding executive compensation at its 2014 Annual Meeting. At that meeting, more than 99% of the votes cast by Targa's shareholders approved the compensation paid to its named executive officers as described in the CD&A and the other related compensation tables and disclosures contained in Targa's Proxy Statement filed with the SEC on April 7, 2014. Targa's board of directors and the Compensation Committee reviewed the results of this vote and concluded that, with this level of support, no changes to the compensation design and philosophy needed to be considered. In accordance with the preference expressed by Targa's shareholders to conduct an advisory vote on executive compensation every three years, the next advisory vote will occur as part of the 2017 Annual Meeting. At the 2017 Annual Meeting, Targa's shareholders will also have the opportunity to vote on the frequency of future advisory votes on executive compensation. We are generally not subject to the advisory say on pay vote requirements under the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010.

The following CD&A is presented from the perspective of the Compensation Committee and discusses our general partner's named executive officers in their roles as officers of Targa. The elements of compensation and the Compensation Committee's decisions with respect to determination on payments are not subject to approval by the board of directors of our general partner or the board of directors of Targa (the "Targa Board"). Certain members of the board of directors of our general partner are members of the Targa Board. Messrs. Pearl and Evans and Ms. Dreessen, each a director of our general partner, were observers at Compensation Committee meetings in 2015. As used in this CD&A (other than in this "Overview"), references to "our," "we," "us," the "Company," and similar terms refer to Targa, references to the "Board" or "Board of Directors" refers to the Targa Board, and references to the Partnership refer to us, Targa Resources Partners LP.

Summary of Key Strategic Results

Our main source of cash flow is from our general and limited partner interests and, prior to completion of the Buy-In Transaction, our incentive distribution rights 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, our 2015 strategic and operational accomplishments, our 2015 financial results and the 2015 financial results of the Partnership demonstrate the significant increases in both our business scale and diversity and in our results of operations in comparison to 2014. In summary, some of our and the Partnership's more significant financial, operational and strategic highlights in 2015 included**:**

- Excellent execution across our businesses, despite a commodity price environment substantially below expectations, with Partnership Adjusted EBITDA of $1.19 billion, volumes above targets, and dividend and distribution growth achieving public guidance;
- Excellent execution on 2015 expenditures of approximately $680 million for announced expansion projects completed or on track to be completed on or ahead of schedule and on or below budget;
- Continued development of our potential future expansion project portfolio;
- Continued growth and execution of Badlands operations in the Bakken Shale;
- Timely closing of the Atlas mergers, highly effective coordination of pre-closing activities and post-closing operations, and strong business performance; and
- A continued strong track record and performance regarding safety, with several industry safety recognitions in 2015, and compliance in all aspects of our business, including environmental and regulatory compliance.

See "—Components of Executive Compensation Program for Fiscal 2015—Annual Cash Incentive Bonus" for further discussion of these summary highlights. Please also see our Annual Report on Form 10-K for the year ended December 31, 2015 for a reconciliation of Adjusted EBITDA to net income and net cash provided by operating activities.

As we enter 2016, our industry continues to be significantly impacted by lower crude oil, natural gas prices and NGL prices. In this period of commodity price uncertainty, we have adapted our business strategies to preserve liquidity and financial strength. We believe the Buy-In Transaction, which was completed on February 17, 2016, provides immediate and long-term benefits to the Company's and the Partnership's investors, and best positions the combined companies to manage successfully through the current commodity price environment with an improved coverage ratio and credit profile, simplified corporate structure and lower cost of capital. As such, the Buy-In Transaction is intended to deliver immediate and significant value to our shareholders and the Partnership's former common unitholders.

Summary of 2015 and 2016 Compensation Decisions

While the compensation arrangements for our named executive officers during fiscal 2015 remained substantially similar to those in place during fiscal 2014, specific compensatory changes in 2015 included the following:

- Base salary raises were approved for the named executive officers ranging from 6.4% to 29.5%. 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 2015 Peer Group, adjusted for company size, and to reflect professional growth and the assumption of additional responsibilities. See "—Methodology and Process—Role of Peer Group and Benchmarking" for a description of the companies that comprise the 2015 Peer Group and of the methodology employed by BDO USA, LLC, the independent compensation consultant engaged by the Compensation Committee (the "Compensation Consultant"), to adjust Peer Group total direct compensation for company size.

- The target bonus percentage for Mr. Meloy for 2015 under our annual cash incentive bonus plan was increased in order to align his total direct compensation more closely with the total direct compensation provided to similarly situated officers at companies within our 2015 Peer Group, adjusted for company size. For similar reasons, the long-term equity incentive award opportunities for 2015 for the named executive officers were also increased.

Although as described above under "—Summary of Key Strategic Results," and as discussed further below under "—Components of Executive Compensation Program for Fiscal 2015—Annual Cash Incentive Bonus," our overall performance on the 2015 business priorities exceeded expectations for the year, in light of the current industry conditions and uncertainty, in January 2016, the Compensation Committee approved funding of a cash bonus pool at 75% of target under the 2015 Bonus Plan. In connection with this approval and our current focus on reducing cash expenses, the Compensation Committee provided that no cash bonuses would be paid to our named executive officers under the 2015 Bonus Plan, and that these officers would instead receive restricted stock unit awards in an amount corresponding to 75% of their respective target bonus amounts under the 2015 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. The Compensation Committee also approved the use of restricted stock unit awards instead of cash bonuses for all other officers of the Company or its subsidiaries and in lieu of a portion of cash bonuses for certain other employees.

With respect to 2016 compensation, the Compensation Committee approved management's recommendations for changes to Mr. Meloy's total compensation and, in the context of the difficult industry environment, management's recommendations for no changes to the base salaries, target bonus percentages and long-term equity incentive award opportunities for the other named executive officers for 2016. The changes to Mr. Meloy's compensation were made to complete a phased transition to bring his total direct compensation more closely in line with the total direct compensation provided to similarly situated executives at companies within our 2016 Peer Group, adjusted for company size. Consistent with the recommendation of Mr. Perkins and Mr. Whalen, our Executive Chairman, and at their request and in the context of a difficult industry environment including commodity price levels and related uncertainties and the resulting impact on the Company's businesses and customers, the Compensation Committee approved the future award of quarterly grants of restricted stock to Mr. Perkins and to Mr. Whalen in lieu of all of their 2016 base salary. These restricted stock awards will be granted on the last business day of each quarter, each with a one year vesting period. The number of restricted shares to be awarded will be determined by dividing one-fourth of the officer's annual base salary by the average closing price of the shares of common stock for all trading days during the quarter ending on the date that is five business days prior to the last business day of the quarter. In addition, for 2016, the Compensation Committee awarded the full amount of the long-term equity incentive awards in the form of restricted stock unit awards under our Stock Incentive Plan (instead of utilizing a combination of long-term incentive awards settled in both Company equity and Partnership equity as had been the case in recent years) due to the Buy-In Transaction, as Partnership common units would no longer be publicly traded. See "—Changes for 2016" for additional information regarding named executive officer compensation for fiscal 2016 and for a description of our Peer Group companies for 2016.

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 Benchmarking" 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 2015 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 Cash Incentive Bonus	Variable cash 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 unit awards granted under our Stock Incentive Plan Equity-settled performance unit awards granted under the Partnership's Long-Term 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 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" cash change in control payments	· 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
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

Fiscal 2015 Total Direct Compensation

We review the mix of base salary, annual cash 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 continue to utilize a similar, though not identical, mix of compensation in future years.

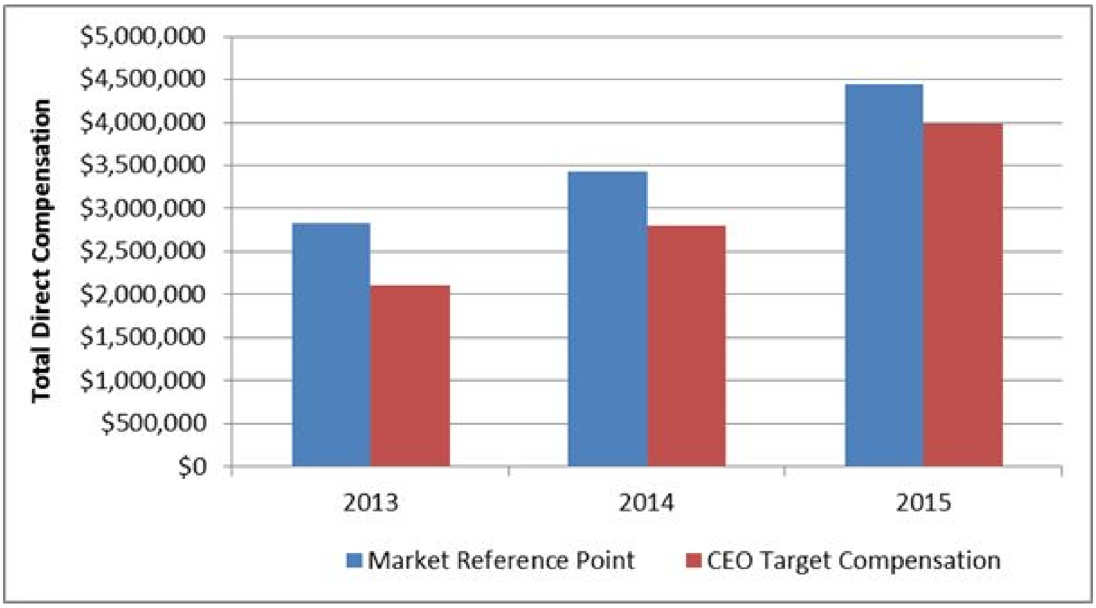
The approximate allocation of target total direct compensation for our named executive officers in fiscal 2015 is presented below. This reflects (i) the salary rates in effect as of December 31, 2015, (ii) target annual cash incentive bonuses for services performed in fiscal 2015, and (iii) the grant date fair value of long-term equity incentive awards granted during fiscal 2015.

Fiscal 2015 Target Total Direct Compensation

	Joe Bob Perkins	Michael A. Heim	Jeffrey J. McParland	Paul W. Chung	Matthew J. Meloy
Base Salary	21%	25%	28%	28%	30%
Annual Cash Incentive Bonus	21%	23%	26%	26%	24%
Long-Term Equity Incentive Awards	58%	52%	46%	46%	46%
Total	100%	100%	100%	100%	100%

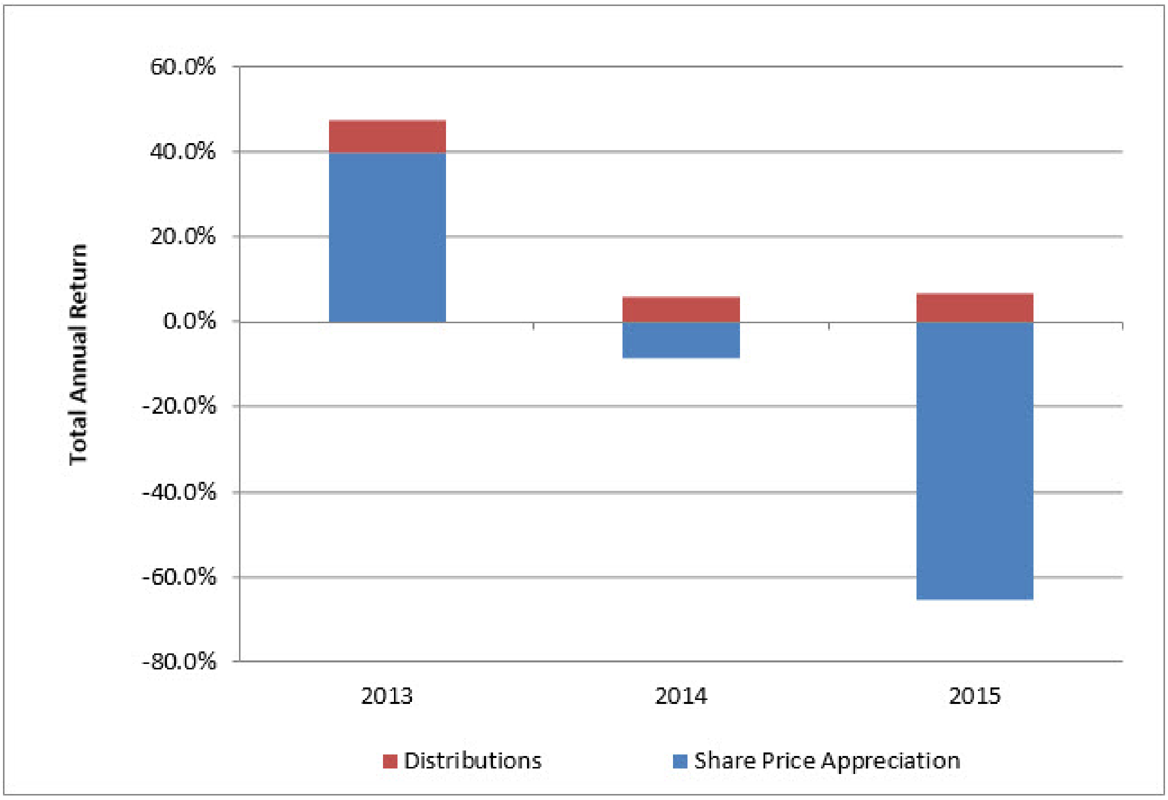
Over the last three calendar years, the target total direct compensation (base salary plus target annual cash incentive bonus plus grant date fair value of long-term equity incentive awards) as set by the Compensation Committee for our Chief Executive Officer has resulted in target compensation that has averaged approximately 82% of the median market total direct compensation levels. The median market 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 median market level developed by our Compensation Consultant for the last three years.

Because incentive compensation (*i.e.*, target annual cash incentive bonus and grant date fair value of long-term equity incentive awards) comprised 79% of our Chief Executive Officer's total direct compensation opportunity for 2015, the amount of compensation he ultimately realizes from these awards may be more or less than the target amount as determined in particular by our Compensation Committee's evaluation of our performance and the total shareholder return on our common stock.



Annual Total Unitholder Return

In the last three calendar years, we have delivered annual total returns to our unitholders of -58.6% (for 2015), -2.5% (for 2014) and 47.5% (for 2013).



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 2015. During 2014 and 2015, the Compensation Committee received advice from the Compensation Consultant with respect to the development and structure of our 2015 executive compensation program. The Compensation Committee has concluded that we do not have any conflicts of interest with the Compensation Consultant.

Role of Peer Group and Benchmarking

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 for executives in our Peer Group as well as 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 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) available compensation data, rankings and comparisons, (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 cash 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 2015 included companies in three comparator groups: (1) midstream master limited partnerships ("MLPs"), (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 MLPs. 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 many companies in the Peer Group may be larger 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 2015, the regressed data was analyzed separately for each of the three comparator groups and then weighted as follows to develop a reference point for assessing our total executive pay opportunity relative to market practice: (1) MLPs (given a 70% weighting), (2) E&Ps (given a 15% weighting) and (3) utility companies (given a 15% weighting). For 2015, the "Peer Group" companies (for purposes of determining 2015 compensation levels) were:

- *MLP peer companies*: Access Midstream Partners, L.P., Atlas Pipeline Partners, L.P. (acquired by us in February 2015), Boardwalk Pipeline Partners, L.P., Buckeye Partners, L.P., DCP Midstream Partners, L.P., Enable Midstream Partners, L.P., Enbridge Energy Partners, L.P., Energy Transfer Partners, L.P., EnLink Midstream Partners, L.P., Enterprise Products Partners L.P., Genesis Energy, L.P., Magellan Midstream Partners, L.P., MarkWest Energy Partners, L.P., NuStar Energy L.P., ONEOK, Inc., Plains All American Pipeline, L.P., Regency Energy Partners L.P., Summit Midstream Partners, L.P. and Williams Companies, Inc.

- *E&P peer companies*: Apache Corporation, Cabot Oil & Gas Corporation, Cimarex Energy Company, Denbury Resources Inc., Devon Energy Corporation, EOG Resources, Inc., Halcon Resources Corporation, Murphy Oil Corporation, Newfield Exploration Company, Noble Energy, Inc., Pioneer Natural Resources Company, QEP Resources, Inc., SM Energy Company, Southwestern Energy Company and Ultra Petroleum Corporation

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

The Peer Group companies we historically used for compensation comparison purposes had remained fundamentally unchanged since our current approach using regression analysis to adjust for company size was initially developed in 2010. During 2013, we worked with our Compensation Consultant to make a number of changes to the composition of our Peer Group used for 2014 and 2015 compensation purposes in order to reflect the change in ownership status of some of the peer companies and create more balance in the make-up of the Peer Group. Based upon the recommendation of our Compensation Consultant, we made the following changes to the 2014 Peer Group to create the 2015 Peer Group: (i) added two companies—Enable Midstream Partners, L.P. and Summit Midstream Partners, L.P. and (ii) recognized the name change of Crosstex Energy, L.P. to Enlink Midstream Partners, LP which was made in connection with the combination of Devon Energy Corporation's midstream business with the assets of Crosstex.

Senior management and the Compensation Committee review our compensation-setting practices and Peer Group companies on at least an annual basis. See "—Changes for 2016" for a description of the changes that were made to the Peer Group for 2016 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 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 cash 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 cash 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, the full Board of Directors and/or the full board of directors of the General Partner. The Chairman of the Compensation Committee may request that senior management provide him with additional information or reconsider or revise the proposal. The resulting recommendation is then submitted for consideration to the full Compensation Committee, which typically invites other members of the Board of Directors and the directors of the General Partner, and also meets separately with the Compensation Consultant. The final compensation decisions are 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 2015

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 cash 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 Benchmarking" are also considered.

For 2015, the Compensation Committee authorized increases in base salary for our named executive officers, effective March 1, 2015, as set forth in the following table. The changes to Messrs. Perkins' and Meloy's base salary rates were part of a phased transition to bring total direct compensation more closely in line with the total direct compensation provided to similarly situated executives at companies within our 2015 Peer Group. With the changes implemented for 2015, total target direct compensation for Mr. Perkins is 90% and for Mr. Meloy is 81% of the median market total direct compensation for similarly situated executives. Similarly, salaries for the other named executive officers were increased to better align total direct compensation opportunities with the target total direct compensation provided to similarly situated executives at companies within our 2015 Peer Group, adjusted for company size, and to reflect professional growth, the assumption of additional responsibilities and individual performance.

	Prior Salary	Base Salary Effective March 1, 2015	Percent Increase
Joe Bob Perkins	$ 560,000	$ 725,000	29.5%
Michael A. Heim	535,000	600,000	12.1%
Jeffrey J. McParland	470,000	500,000	6.4%
Paul W. Chung	460,000	490,000	6.5%
Matthew J. Meloy	375,000	400,000	6.7%

Annual Cash Incentive Bonus

For 2015, our named executive officers were eligible to receive annual cash incentive bonuses under the 2015 Annual Incentive Plan (the "2015 Bonus Plan"), which was approved by the Compensation Committee in January 2015. The funding of the cash bonus pool and the payment of individual cash bonuses to executive management, including our named executive officers, are subject to the sole discretion of the Compensation Committee and will generally be determined near or following the end of the year to which the bonus relates.

The target amount of the cash bonus pool for all employees is equal to the sum of the target bonus amounts for all participants in the 2015 Bonus Plan. Each participant's target bonus amount is equal to the product of the participant's base salary (at the rate in effect as of the last day of the year to which the bonus relates) and the participant's target bonus percentage, which may generally range from 5% to 100%. For purposes of the 2015 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	100%	$ 725,000
Michael A. Heim	90%	540,000
Jeffrey J. McParland	90%	450,000
Paul W. Chung	90%	441,000
Matthew J. Meloy	80%	320,000

For 2015, the target bonus percentage for Mr. Meloy was increased from 75% to 80% to align his total direct compensation more closely with the total direct compensation provided to similarly situated officers at companies within our Peer Group, adjusted for company size. The Compensation Committee did not change the target bonus percentages for the other named executive officers from the levels in effect in 2014.

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 cash bonus pool, which are generally consistent with both Peer Group company and broader energy compensation practices.

The Compensation Committee, after consultation with the Chief Executive Officer, established the following overall threshold, target and maximum levels for the 2015 Bonus Plan: (i) 50% of the target amount of the cash 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 cash 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 cash 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 cash 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 the Compensation Committee ultimately determines the total amount to be allocated to the cash 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 cash bonus pool and the amount of individual bonus awards under the 2015 Bonus Plan, the Compensation Committee focused on the business priorities listed in the table below. 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. 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.

<table>
<tr><th>2015 Business Priority</th><th>Committee Consensus</th><th>Overall Assessment</th></tr>
<tr><td>Execute on all business dimensions, including 2015 guidance for Adjusted EBITDA and distribution / dividend growth as furnished from time to time</td><td>Exceeded</td><td rowspan="11">Excellent execution across our businesses, even with commodity price environment substantially below expectations, including:
exceeding volume targets for field G&P and exports,
achieving dividend growth of 23.9% and distribution growth of 4.6% compared to guidance of 25% and 4-5% respectively,
Partnership Adjusted EBITDA of $1.19 billion despite significantly lower price environment,
significant operating and G&A cost savings,
strong credit, inventory, hedging and balance sheet management and capital markets execution
Timely closing of the Atlas mergers; highly effective coordination of pre-closing activities and post-closing operations; successful talent retention; business performance stronger than expected
Continued growth and execution of Badlands operations in the Bakken in challenging environment, including crude oil volumes 14% and natural gas volumes 26% above 2014, meaningful progress on difficult right of way issues
2015 growth capital expenditures of approximately $680 million completed or on track to be completed on or ahead of schedule and on or below budget, including:
excellent execution on expansion projects including: Cedar Bayou Fractionator (“CBF”) Train 5 construction; startup of Little Missouri Plant; and the interconnection of Sand Hills and SAOU with West Texas,
significant capital expenditure discipline and flexibility for timing of new projects while adding Permian and Oklahoma expansions and Sanchez joint ventures,
continued development of our potential future expansion project portfolio
Strong track record and performance regarding safety and compliance in all aspects of our business, including environmental and regulatory compliance; continued industry recognition through safety awards
Structuring of the acquisition by the Company of all of the Partnership’s outstanding publicly traded common units</td></tr>
<tr><td>Close the Atlas mergers—retaining talent at both companies and actively pursuing growth opportunities to achieve business performance consistent with expectations for the merger in the context of prevailing market conditions</td><td>Exceeded</td></tr>
<tr><td>Continue the expansion of system capabilities and the commercialization of Badlands including volume targets for 2015</td><td>Exceeded</td></tr>
<tr><td>Continue priority emphasis and strong performance relative to a safe workplace</td><td>Exceeded</td></tr>
<tr><td>Reinforce business philosophy and mindset that promotes compliance with all aspects of our business including environmental and regulatory compliance</td><td>Achieved</td></tr>
<tr><td>Continue to attract and retain needed operational and professional talent</td><td>Achieved</td></tr>
<tr><td>Continue to control all costs—operating, capital and general and administrative (“G&A”)</td><td>Exceeded</td></tr>
<tr><td>Continue to manage tightly credit, inventory, interest rate and commodity price exposures</td><td>Exceeded</td></tr>
<tr><td>Execute on major capital and development projects—finalizing negotiations, completing projects on time and on budget, and optimizing economics and capital funding</td><td>Exceeded</td></tr>
<tr><td>Pursue selected growth opportunities, including new gathering and processing (“G&P”) build-outs, fee-based capital expenditure projects and potential purchases of strategic assets</td><td>Achieved</td></tr>
<tr><td>Pursue commercial and financial approaches to achieve maximum value and manage risks</td><td>Achieved</td></tr>
</table>

After assessing the results of the 2015 business priorities as summarized above, the Compensation Committee determined in January 2016 that overall performance relative to the 2015 business priorities exceeded expectations. This subjective assessment that performance exceeded expectations was based on a qualitative evaluation 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 2015 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 2015. 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 management performance overall and the performance of individual executive officers.

Despite the Compensation Committee's determination that overall performance on the 2015 business priorities exceeded expectations for the year, the Compensation Committee, in its sole discretion, approved an annual cash bonus pool equal to 75% of the target level under the 2015 Bonus Plan. The Compensation Committee, consistent with management's recommendation, determined to fund the bonus pool at 75% of target level due to the overall industry environment including commodity price levels and related future uncertainties and the resulting impact on the Company's businesses and customers. These considerations reduced the payout level that might otherwise have been funded given the Compensation Committee's determination that overall performance, including organizational performance, exceeded expectations with respect to the 2015 business priorities. In light of the current industry environment and the Company's resulting focus on reducing cash expenses, the Compensation Committee also determined that cash bonuses would not be paid to our named executive officers under the 2015 Bonus Plan, and that these officers would instead receive restricted stock unit awards in an amount corresponding to 75% of target value under the 2015 Bonus Plan. The 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. The Compensation Committee also similarly approved the use of restricted stock unit awards instead of cash bonuses for all other officers of the Company or its subsidiaries and in lieu of a portion of cash bonuses for certain other employees.

To determine the value of the restricted stock unit awards to be made to each named executive officer instead of a cash bonus under the 2015 Bonus Plan, the Compensation Committee also evaluated the executive group and each officer's individual performance for the year. Based on this evaluation, each named executive officer was granted a restricted stock unit award with a value equal to 75% of the respective target bonus amount that would have been paid to that officer under the 2015 Bonus Plan, multiplied by a designated multiple determined by the Compensation Committee for each named executive officer based on his individual performance. The Compensation Committee determined that a performance multiplier of 1.0x should be applied to each named executive officer for 2015. The number of restricted stock units actually awarded to each named executive officer was determined by dividing the total dollar value allocated to the award by the ten-day average closing price of the shares of common stock for the period ending five business days prior to the date of grant (February 29, 2016). The number of restricted stock units awarded instead of cash bonuses was calculated in a similar manner for other employees receiving stock units instead of cash. The following table reflects the grant date value of the number of restricted stock units awards to be received by our named executive officers with respect to the 2015 Bonus Plan:

	Target Bonus Amount	Individual Performance Factor	Company Performance Factor	Equity Award Value In Lieu of Cash Bonus Amount
Joe Bob Perkins	$ 725,000	1.0	0.75	$ 543,750
Michael A. Heim	540,000	1.0	0.75	405,000
Jeffrey J. McParland	450,000	1.0	0.75	337,500
Paul W. Chung	441,000	1.0	0.75	330,750
Matthew J. Meloy	320,000	1.0	0.75	240,000

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. 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.

For 2015, the Compensation Committee determined the amount of long-term equity incentive awards under the Stock Incentive Plan and recommended to the board of directors of the General Partner an amount of long-term equity incentive awards under the Partnership’s Long-Term Incentive Plan that it believed 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 Long-Term Incentive Plan awards were ultimately approved by the General Partner’s board of directors. Long-term equity incentive awards to our named executive officers under the Stock Incentive Plan and the Long-Term Incentive Plan are generally made near the beginning of each year.

For 2015, the value of the long-term equity incentive component of our named executive officers’ compensation was allocated approximately (i) forty percent (40%) to restricted stock units under the Stock Incentive Plan and (ii) sixty percent (60%) to equity-settled performance unit awards under the Partnership’s Long-Term Incentive Plan. Upon the recommendation of senior management, the Compensation Committee decided to change our historical allocation of (i) twenty-five percent (25%) awards under the Stock Incentive Plan and (ii) seventy-five percent (75%) awards under the Partnership’s Long-Term Incentive Plan so that the mix of awards would be more closely aligned with the relative market capitalizations of the Company and the Partnership. This allocation of the dollar value of the awards is based on average market prices of the underlying securities prior to the date of grant. 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 or units 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 or units for the period ending five business days prior to the date of grant. For 2015, 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	350%	$ 2,537,500
Michael A. Heim	250%	1,500,000
Jeffrey J. McParland	200%	1,000,000
Paul W. Chung	200%	980,000
Matthew J. Meloy	190%	760,000

For Messrs. Perkins, Heim, McParland, Chung and Meloy, the base salary percentages used to determine the dollar values of the long-term equity incentive awards were increased from the percentages used in 2014 (300%, 225%, 170%, 170% and 150%, respectively) to align their total direct compensation more closely with similarly situated executives at companies within our 2015 Peer Group, adjusted for company size.

For the 2015 awards to our named executive officers, the Compensation Committee determined that a combination of equity awards consisting of restricted stock units (40% of award value) and equity-settled performance units (60% of award value) would provide an appropriate balance of performance-based long-term incentives and of parent and subsidiary MLP equity. The restricted stock unit awards are time-based awards that capture absolute total return performance of our common stock, and the equity-settled performance unit awards were intended to reflect both the absolute total return of the Partnership’s common units with variable performance based on the total return of the Partnership’s units in relation to the LTIP Peer Group (defined below). Also, this mix was designed to effectively align the named executive officer’s interests with both the interests of our shareholders and the interests of the Partnership’s unitholders. The larger portion of each named executive officer’s long-term equity incentive compensation allocated to equity-settled performance unit awards linked executive compensation not only to the value of Partnership equity over time, but also to the relative performance of the Partnership compared to other midstream partnerships.

Restricted Stock Unit Awards. In 2013 and prior years, the Compensation Committee awarded restricted stock awards to the named executive officers under the terms of our Stock Incentive Plan. For 2014 and 2015, the Compensation Committee decided to award restricted stock units, which will settle in shares of our common stock, instead of restricted stock awards. The terms and conditions of the restricted stock unit awards are substantially similar to the terms and conditions of the previously granted and outstanding restricted stock awards, except that under the restricted stock unit awards, shares of stock are not delivered until the awards vest. The Compensation Committee determined that the use of restricted stock units provides greater design flexibility in our equity award program than restricted stock awards.

On January 15, 2015, our named executive officers were awarded restricted stock units under the Stock Incentive Plan which settle in shares of our common stock in the following amounts: (i) 9,912 restricted stock units to Mr. Perkins, (ii) 5,859 restricted stock units to Mr. Heim, (iii) 3,906 restricted stock units to Mr. McParland, (iv) 3,828 restricted stock units to Mr. Chung and (v) 2,969 restricted stock units to Mr. Meloy. 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 Unit Awards. Our named executive officers also received annual awards of equity-settled performance units under the Partnership's Long-Term Incentive Plan for 2015. The vesting of these awards was dependent on the satisfaction of certain service-related conditions and the Partnership's performance relative to the performance of a specified comparator group of publicly-traded partnerships (the "LTIP Peer Group"). The LTIP Peer Group is not composed of the same companies as the peer group companies employed for developing market reference points for executive pay because the companies in those groups are those with which we compete for executive talent. Companies in the LTIP Peer Group are principally those companies with which the Partnership competes to varying extents in the midstream sector. The performance unit awards, which were designed to settle in Partnership common units, were intended to align the interests of the named executive officers and other key employees with those of the Partnership's equity holders. As described in greater detail below under "—Changes for 2016," performance unit awards outstanding on February 17, 2016 were converted and restated into comparable awards based on Company common shares in connection with the completion of the Buy-In Transaction. The terms of the performance unit awards as granted in 2015 are described below in this section.

On January 21, 2015, our named executive officers were awarded equity-settled performance units under the Partnership's Long-Term Incentive Plan in the following amounts: (i) 32,168 performance units to Mr. Perkins, (ii) 19,015 performance units to Mr. Heim, (iii) 12,677 performance units to Mr. McParland, (iv) 12,423 performance units to Mr. Chung and (v) 9,634 performance units to Mr. Meloy.

The performance period for the 2015 performance unit awards began on June 30, 2015 and was designated to end on June 30, 2018. Provided a named executive officer remained continuously employed throughout the performance period, his 2015 performance units would vest on June 30, 2018 and would be settled as soon as practicable following the vesting date by the issuance of Partnership common units. In addition, the performance unit awards would continue to vest on the last day of the performance period if, from the date of the executive's retirement through the last day of the performance period, 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 unit awards would remain subject to the applicable performance-based vesting requirements described below during the post-retirement period.

In addition to the service-related conditions, certain performance objectives would have to be achieved in order for the performance unit awards to vest. If the service-related conditions were satisfied, the number of Partnership common units issued would be equal to the number of performance units awarded multiplied by the "performance vesting percentage," which could range from 0% to 150%, dependent upon the relative total return performance of the Partnership's common units compared to the LTIP Peer Group. For performance results that fall between the 25th percentile and the 50th percentile of the LTIP Peer Group, the performance vesting percentage would be interpolated between 25% and 100% and, for performance results that fall between the 50th percentile and 75th percentile, the performance vesting percentage would be interpolated between 100% and 150%. If the Partnership's performance was above the 75th percentile of the LTIP Peer Group, the performance vesting percentage would be 150% of the award. If the Partnership's performance was below the 25th percentile of the LTIP Peer Group, the performance vesting percentage would be 0%.

For the 2015 performance unit awards, the LTIP Peer Group was composed of the Partnership and the following other companies (ticker noted in parenthesis):

Crestwood Midstream Partners L.P. (CMLP)	Magellan Midstream Partners, L.P. (MMP)
Enable Midstream Partners, L.P. (ENBL)	MarkWest Energy Partners, L.P. (MWE)
Enlink Midstream Partners, L.P. (ENLK)	Martin Midstream Partners, L.P. (MMLP)
Enbridge Energy Partners L.P. (EEP)	ONEOK Partners, L.P. (OKS)
Energy Transfer Partners, L.P. (ETP)	Plains All American Pipeline L.P. (PAA)
DCP Midstream Partners, L.P. (DPM)	Williams Partners L.P. (WPZ)

The board of directors of the General Partner retained the ability to modify the LTIP Peer Group in the event a company listed above ceased to be publicly traded or another significant event occurred and a company was determined to no longer be one of the Partnership's peers. Crestwood Midstream Partners L.P. (CMLP) and MarkWest Energy Partners, L.P. (MWE) were both acquired during the fourth quarter of 2015 and ceased to be publicly traded. No replacement companies were designated by the board of directors of the General Partner or the Compensation Committee, and the 2015 performance unit awards were converted and restated into comparable awards based on Company common shares in connection with the completion of the Buy-In Transaction. See "—Changes for 2016" for more information.

For purposes of the performance unit awards, the Partnership's performance would be determined based on the comparison of "total return" of a Partnership common unit for the performance period to the "total return" of a common share/unit of each member of the LTIP Peer Group for the performance period. "Total return" would be measured by (i) subtracting (a) the average closing price per share/unit for the first ten trading days of the performance period (the "Beginning Price") from (b) the sum of (1) the average closing price per share/unit for the last ten trading days of the performance period, plus (2) the aggregate amount of dividends/distributions paid with respect to a share/unit during such period (such result is referred to as the "Value Increase"), and (ii) dividing the Value Increase by the Beginning Price.

During the period the performance unit awards were outstanding, the Partnership accrued any cash distributions paid by the Partnership in an amount equal to the cash distributions paid with respect to a common unit times the number of performance units awarded. At the time the performance unit awards are settled, the named executive officers would also receive a cash payment equal to the product of the performance vesting percentage times the amount of cash distributions accrued with respect to a common unit times the number of such named executive officer's vested units.

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 in our long-term equity incentive awards create important retention tools for us and are consistent with the 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.

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. The Buy-In Transaction also did not trigger the accelerated vesting of any of our outstanding long-term equity incentive compensation awards. See “—Changes for 2016” for a discussion of the impact of the Buy-In Transaction on performance unit awards previously granted under the Partnership’s Long-Term Incentive Plan.

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 manage directly 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 2016

In consultation with the Compensation Consultant and taking into consideration the consummation of the Buy-In Transaction, the Compensation Committee has reviewed our executive compensation program and has made limited changes to the compensation of our named executive officers for 2016, as described in more detail below. The analysis provided by the Compensation Consultant indicated that the current total target direct compensation for 2016 of our Chief Executive Officer and of our Chief Financial Officer remain below the competitive median market levels adjusted for company size using the regression analysis of 2016 Peer Group pay programs. However, due to current commodity market and industry conditions, management recommended and the Compensation Committee concurred that no changes would be made to the base salary levels, annual cash incentive award opportunities or long-term equity incentive award opportunities of the named executive officers, other than the salary level and target bonus percentage adjustments for Mr. Meloy as described below. For 2016, total target direct compensation for Mr. Perkins is still only 87% of the median market total direct compensation for similarly situated executives, while the total target direct compensation for our other named executive officers is more closely aligned with the total direct compensation provided to similarly situated executives at companies within our 2016 Peer Group.

2016 Peer Group

Based upon the recommendation of our Compensation Consultant, we made the following changes to the 2015 Peer Group used for compensation comparison purposes to create the 2016 Peer Group: (i) added Crestwood Equity Partners, L.P. as a MLP peer company and (ii) removed Atlas as a MLP peer company due to its acquisition by the Company in 2015.

Base Salary

To date in 2016, the Compensation Committee has not authorized any changes to the base salary rates in effect for the named executive officers during 2015, other than for Mr. Meloy, whose base salary was increased from $400,000 to $460,000, effective March 1, 2016. The change to Mr. Meloy's base salary is part of a phased transition to bring his total direct compensation more closely in line with the total direct compensation provided to similarly situated executives at companies within our 2016 Peer Group.

Consistent with the recommendation of Mr. Perkins and Mr. Whalen, our Executive Chairman, and at their request and in the context of a difficult industry environment including commodity price levels and related uncertainties and the resulting impact on the Company's businesses and customers, the Compensation Committee approved the future award of quarterly grants of restricted stock to Mr. Perkins and to Mr. Whalen in lieu of all of their 2016 base salary. These restricted stock awards will be granted on the last business day of each quarter, each with a one year vesting period. The number of restricted shares to be awarded will be determined by dividing one-fourth of the officer's annual base salary by the average closing price of the shares of common stock for all trading days during the quarter ending on the date that is five business days prior to the last business day of the quarter.

Annual Cash Incentive Bonus

In preparing our business plan for 2016, senior management developed and proposed a set of business priorities to the Compensation Committee, which discussed and adopted the proposed business priorities for purposes of the 2016 Annual Incentive Plan (the "2016 Bonus Plan"). The 2016 business priorities are similar to those in effect for 2015 but have been revised to modify certain objectives and to remove certain goals that have been achieved. The Committee has established the following eight key business priorities for 2016:

- execute on all business dimensions, including 2016 business plan and dividend guidance,
- continue priority emphasis and strong performance relative to a safe workplace,
- reinforce business philosophy and mindset that promote compliance in all aspects of the Company's business including environmental and regulatory compliance,
- continue to attract and retain the operational and professional talent needed in the Company's businesses,
- continue to control all costs—operating, capital and general and administrative consistent with the existing business environment,
- execute on major capital and development projects—finalizing negotiations, completing projects on time and on budget, and optimizing economics and capital funding
- pursue selected growth opportunities including gathering and processing build outs, fee-based capex projects, and potential purchases of strategic assets, and
- pursue commercial and financial approaches to achieve maximum value and manage risks, including contract, credit, inventory, interest rate and commodity price exposures.

The overall threshold, target and maximum funding percentages for the 2016 Bonus Plan remain the same as for the 2015 Bonus Plan. The target bonus percentages of all named executive officers remain the same as in 2015, except Mr. Meloy's target bonus percentage has been increased from 80% to 90%, effective in 2016. As with the 2015 Bonus Plan, funding of the cash bonus pool and the payment of individual cash bonuses to executive management, including our named executive officers, is subject to the sole discretion of the Compensation Committee.

Long-Term Equity Incentive Awards

For 2016, the Compensation Committee determined that the long-term equity incentive component of our named executive officers' compensation will consist solely of restricted stock unit awards under the Stock Incentive Plan due to the Buy-In Transaction, which resulted in all outstanding common units of the Partnership not already owned by the Company being acquired by the Company and the Partnership's common units ceasing to be publicly traded. For 2016, the percentage of base salary used to determine the total dollar value of the annual long-term equity incentive awards granted to all named executive will remain the same as in 2015. On January 19, 2016, our named executive officers were awarded equity-settled restricted stock units under the Stock Incentive Plan in the following amounts: (i) 102,484 restricted stock units to Mr. Perkins, (ii) 60,582 restricted stock units to Mr. Heim, (iii) 40,388 restricted stock units to Mr. McParland, (iv) 39,580 restricted stock units to Mr. Chung and (v) 35,299 restricted stock units to Mr. Meloy. 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 for the period ending five business days 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.

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), 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 which 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. There was no acceleration of vesting and no monetary value received by our named executive officers in connection with the conversion. See "Executive Compensation—Outstanding Equity Awards at 2015 Fiscal Year End" for information regarding performance unit awards held by the named executive officers as of December 31, 2015.

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, restricted stock and/or restricted stock unit agreements covering grants made to our named executive officers and other employees in 2011 and later years do 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.

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.

Compensation Risk Assessment

The Compensation Committee reviews the relationship between our risk management policies and compensation policies and practices each year and, for 2015, 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 the Compensation Committee retains the sole discretion for determining the actual amount paid to executives pursuant to the annual cash incentive bonus program, the 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 2015 with three-year vesting and performance periods serves our executive compensation program's goal of aligning the interests of executives and unitholders, thereby reducing the incentives to unnecessary risk-taking.

COMPENSATION COMMITTEE REPORT

In fulfilling its oversight responsibilities, the board of directors of our general partner has reviewed and discussed with management the Compensation Discussion and Analysis contained in our Annual Report on Form 10-K for the year ended December 31, 2015. Based on these reviews and discussions, the board of directors of our general partner recommended that the Compensation Discussion and Analysis be included in our Annual Report on Form 10-K for the year ended December 31, 2015 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.

Rene R. Joyce	Michael A. Heim	James W. Whalen
Robert B. Evans	Barry R. Pearl	Joe Bob Perkins
Ruth I. Dreessen		

EXECUTIVE COMPENSATION

Summary Compensation Table for 2015

The following Summary Compensation Table sets forth the compensation of our named executive officers for 2015, 2014 and 2013. 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)	All Other Compensation (3)	Total
Joe Bob Perkins	2015	$ 697,500	$ -	$ 2,066,608	$ 22,720	$ 2,786,828
Chief Executive Officer	2014	554,167	1,120,000	1,552,665	21,931	3,248,763
	2013	517,500	918,750	1,012,070	21,456	2,469,776
Matthew J. Meloy (4)	2015	395,833	-	618,968	22,196	1,036,997
Executive Vice President	2014	366,667	562,500	519,890	21,548	1,470,605
and Chief Financial Officer	2013	316,667	355,469	360,238	21,046	1,053,420
Michael A. Heim (5)	2015	589,167	-	1,221,592	22,628	1,833,387
Vice Chairman of Targa	2014	526,667	963,000	1,112,536	21,874	2,624,077
Resources GP LLC Board	2013	480,833	679,000	888,231	21,381	2,069,445
Jeffrey J. McParland	2015	495,000	-	814,407	22,448	1,331,855
President—Finance and Administration	2014	463,333	846,000	738,476	21,745	2,069,554
Paul W. Chung Executive Vice President, General Counsel and Secretary	2015	485,000	-	798,112	22,422	1,305,534

(1) For 2015, the Compensation Committee provided that no bonuses would be paid to our named executive officers in cash under the 2015 Bonus Plan, and that these officers would instead receive restricted stock unit awards in an amount corresponding to 75% of their respective target bonus amounts under the 2015 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 will be granted on February 29, 2016, and will therefore be reported as compensation in the Summary Compensation Table for 2016 in accordance with SEC rules Please see “Compensation Discussion and Analysis—Components of Executive Compensation Program for Fiscal 2015—Annual Cash Incentive Bonus.” As discussed above, payments pursuant to our Bonus Plan are discretionary and not based on objective performance measures.

(2) Amounts reported in the “Stock Awards” column represent the aggregate grant date fair value of restricted stock unit awards under our Stock Incentive Plan and of equity-settled performance unit awards under the Partnership’s Long-Term Incentive Plan, in each case, granted in 2015 and computed in accordance with FASB ASC Topic 718. Assumptions used in the calculation of these amounts are included in Note 22 to our “Consolidated Financial Statements” beginning on page F-1 of our Annual Report on Form 10-K for fiscal year 2015. Detailed information about the amount recognized for specific awards is reported in the table under “—Grants of Plan-Based Awards for 2015” below. The grant date fair value of each restricted stock unit subject to the restricted stock unit awards granted on January 15, 2015, assuming vesting will occur, is $86.545. The aggregate grant date fair value for the equity-settled performance unit awards granted on January 19, 2015 is determined by multiplying a number of units equal to approximately 80.43% of the number of performance units awarded by $46.72, and that value is consistent with the estimate of aggregate compensation cost to be recognized over the service period of the awards, excluding the effect of estimated forfeitures. Assuming, instead, a payout percentage for these performance unit awards of 150%, 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 21, 2015 for each named executive officer is as follows: Mr. Perkins—$2,254,333; Mr. Meloy—$675,151; Mr. Heim —$1,332,571; Mr. McParland—$888,404; and Mr. Chung—$870,604.

(3) For 2015, “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	$ 21,200	$ 1,520	$ 22,720
Matthew J. Meloy	21,200	996	22,196
Michael A. Heim	21,200	1,428	22,628
Jeffrey J. McParland	21,200	1,248	22,448
Paul W. Chung	21,200	1,222	22,422

(4) Mr. Meloy served as Senior Vice President, Chief Financial Officer and Treasurer of the Company and the General Partner prior to his promotion to the Executive Vice President role in May 2015.

(5) On November 12, 2015, Mr. Heim was appointed as Vice Chairman of the Board of the General Partner. In connection with his new role as Vice Chairman of the Board of the General Partner, Mr. Heim resigned from his positions as President and Chief Operating Officer of the General Partner and the Company. Mr. Heim continues to be an employee of the Company and a member of its executive management team and is expected to become a director and Vice Chairman of the Company following the close of the Buy-In Transaction.

Grants of Plan-Based Awards for 2015

The following table and the footnotes thereto provide information regarding grants of plan-based equity awards made to the named executive officers during 2015:

		Estimated Future Payouts Under Equity Incentive Plan Awards (1)				
Name	Grant Date	Threshold (#)	Target (#)	Maximum (#)	All Other Stock Awards: Number of Shares of Stock or Units (1)	Grant Date Fair Value of Equity Awards (2)
Mr. Perkins	01/15/15				9,912	$ 857,834
	01/21/15	11,484	32,168	48,252		1,208,774
Mr. Meloy	01/15/15				2,969	256,952
	01/21/15	3,439	9,634	14,451		362,016
Mr. Heim	01/15/15				5,859	507,067
	01/21/15	6,788	19,015	28,523		714,525
Mr. McParland	01/15/15				3,906	338,045
	01/21/15	4,526	12,677	19,016		476,362
Mr. Chung	01/15/15				3,828	331,294
	01/21/15	4.435	12,423	18,635		466,818

(1) The grants on January 15, 2015 are restricted stock unit awards granted under our Stock Incentive Plan. The grants on January 21, 2015 are equity-settled performance units granted under the Partnership's Long-Term Incentive Plan. For a detailed description of how performance achievements will be determined for the equity-settled performance units, see "Compensation Discussion and Analysis—Components of Executive Compensation Program for Fiscal 2015—Long-Term Equity Incentive Awards—Equity-Settled Performance Unit Awards."

(2) The dollar amounts shown for the restricted stock unit awards granted on January 15, 2015 are determined by multiplying the shares reported in the table by $86.545, which is the grant date fair value of awards computed in accordance with FASB ASC Topic 718. The dollar amounts shown for the equity-settled performance units granted on January 21, 2015 are determined by multiplying a number of units equal to approximately 80.43% of the number of units reported in the table under the "Target" column by $46.72, which is the grant date fair value of awards computed in accordance with FASB ASC Topic 718, and that value is consistent with the estimate of aggregate compensation cost to be recognized over the service period of the awards, excluding the effect of estimated forfeitures.

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

A discussion of 2015 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 2015 restricted stock unit awards under our Stock Incentive Plan and the 2015 equity-settled performance unit awards under the Partnership's Long-Term Incentive Plan, such as the vesting schedule of such awards, any applicable performance-based conditions, and the extent to which dividends and distributions are paid with respect to such awards.

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Outstanding Equity Awards at 2015 Fiscal Year-End

The following table and the footnotes related thereto provide information regarding equity-based awards outstanding as of December 31, 2015 for each of our named executive officers.

	Stock Awards			
Name	Number of Shares of Stock That Have Not Vested (1)	Market Value of Shares of Stock That Have Not Vested (2)	Equity Incentive Plan Awards: Number of Unearned Units That Have Not Vested (3)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Units That Have Not Vested (4)
Joe Bob Perkins	19,630	$ 531,188	77,617	$ 1,283,009
Matthew J. Meloy	6,326	171,182	25,295	418,126
Michael A. Heim	13,611	368,314	54,959	908,472
Jeffrey J. McParland	9,006	243,702	36,343	600,750
Paul W. Chung	8,814	238,507	35,561	587,823

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

	January 15, 2013 Award (a)	January 14, 2014 Award (b)	January 15, 2015 Award (c)	Total
Joe Bob Perkins	4,895	4,823	9,912	19,630
Matthew J. Meloy	1,742	1,615	2,969	6,326
Michael A. Heim	4,296	3,456	5,859	13,611
Jeffrey J. McParland	2,806	2,294	3,906	9,006
Paul W. Chung	2,741	2,245	3,828	8,814

(a) The restricted shares subject to the January 15, 2013 awards vested on January 15, 2016.

(b) The restricted stock units subject to the January 14, 2014 awards are subject to the following vesting schedule: 100% of the restricted stock units vest on January 14, 2017, 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.

(c) The restricted stock units subject to the January 15, 2015 awards 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.

The treatment of the outstanding restricted stock awards and 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 or the number of restricted stock units reported in the table by the closing price of a share of our common stock on December 31, 2015 ($27.06). The amounts do not include any related dividends accrued with respect to the awards.

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

	January 15, 2013 Award (a)	January 14, 2014 Award (b)	January 21, 2015 Award (c)	Total
Joe Bob Perkins	20,971	24,478	32,168	77,617
Matthew J. Meloy	7,465	8,196	9,634	25,295
Michael A. Heim	18,405	17,539	19,015	54,959
Jeffrey J. McParland	12,024	11,642	12,677	36,343
Paul W. Chung	11,744	11,394	12,423	35,561

(a) Reflects the number of performance units granted to the named executive officers on January 15, 2013. The outstanding performance unit awards were converted and restated into comparable awards based on the Company's common shares upon completion of the Buy-In Transaction in February 2016. There was no acceleration of vesting in connection with the conversion. The converted awards remain subject to the same time-based vesting schedule (through June 30, 2016) and forfeiture and termination provisions as the performance unit awards, with the number of Company common shares subject to the award determined by multiplying the number of performance units granted 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.

(b) Reflects the number of performance units granted to the named executive officers on January 14, 2014. The outstanding performance unit awards were converted and restated into comparable awards based on the Company's common shares upon completion of the Buy-In Transaction in

February 2016. There was no acceleration of vesting in connection with the conversion. The converted awards remain subject to the same time-based vesting schedule (through June 30, 2017) and forfeiture and termination provisions as the performance unit awards, with the number of Company common shares subject to the award determined by multiplying the number of performance units granted 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.

(c) Reflects the number of performance units granted to the named executive officers on January 21, 2015. The outstanding performance unit awards were converted and restated into comparable awards based on the Company's common shares upon completion of the Buy-In Transaction in February 2016. There was no acceleration of vesting in connection with the conversion. The converted awards remain subject to the same time-based vesting schedule (through June 30, 2018) and forfeiture and termination provisions as the performance unit awards, with the number of Company common shares subject to the award determined by multiplying the number of performance units granted 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.

The treatment of the performance unit awards outstanding as of December 31, 2015 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 performance units reported in the table by the closing price of a common unit of the Partnership on December 31, 2015 ($16.53). The amounts do not include any related cash distributions accrued with respect to the awards.

Option Exercises and Stock Vested in 2015

The following table provides the amount realized during 2015 by each named executive officer upon the vesting of restricted stock and performance unit awards. None of our named executive officers exercised any option awards during the 2015 year and, currently, there are no options outstanding under any of our plans.

	Stock Vested for 2015		Units Vested for 2015	
Name	**Number of Shares Acquired on Vesting (1)**	**Value Realized on Vesting (2)**	**Number of Units Acquired on Vesting (3)**	**Value Realized on Vesting (4)**
Joe Bob Perkins	5,035	$ 449,474	18,620	$ 718,732
Matthew J. Meloy	1,866	166,578	6,903	266,456
Michael A. Heim	4,399	392,699	16,269	627,983
Jeffrey J. McParland	3,390	302,625	12,537	483,928
Paul W. Chung	3,307	295,216	12,231	472,116

(1) Shares of restricted stock granted under our Stock Incentive Plan on January 12, 2012, which vested on January 12, 2015.

(2) Computed with respect to the restricted stock awards granted under our Stock Incentive Plan by multiplying the number of shares of stock vesting by the closing price of a share of common stock on the January 12, 2015 vesting date ($89.27) and does not include associated dividends accrued during the vesting period.

(3) Performance units linked to the performance of the Partnership's common units granted under the Partnership's Long-Term Incentive Plan in January 2012, which vested on June 30, 2015, at the 114.3% payout level.

(4) Computed as the number of performance units vested multiplied by the closing price of a Partnership common unit on June 30, 2015 ($38.60), the vesting date, and does not include associated distributions 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, our Stock Incentive Plan and the Partnership's Long-Term Incentive Plan upon certain specified termination of employment and/or a change in control events, in each case, had such event occurred on December 31, 2015. 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 2015 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	$ 2,252,689	$ 6,645,070	$ 1,927,137	$ 2,560,950
Matthew J. Meloy	737,368	2,953,238	629,294	834,489
Michael A. Heim	1,612,917	5,088,786	1,370,634	1,814,673
Jeffrey J. McParland	1,065,840	3,971,709	906,166	1,199,820
Paul W. Chung	1,042,816	3,888,097	886,634	1,174,003

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 2015 calendar year.

The Change in Control Program is administered by our 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 or 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 Internal Revenue Code for such individual, thereby subjecting the individual to an excise tax under section 4999 of the Internal Revenue 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, 2015.

Name	Qualifying Termination Following Change in Control (1)
Joe Bob Perkins	$ 4,392,381
Matthew J. Meloy	2,215,869
Michael A. Heim	3,475,869
Jeffrey J. McParland	2,905,869
Paul W. Chung	2,845,281

(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, 2015 for each named executive officer and his eligible dependents in the following amounts: (a) Mr. Perkins – $42,381, (b) Mr. Meloy – $55,869, (c) Mr. Heim – $55,869, (d) Mr. McParland– $55,869, and (e) Mr. Chung - $52,281.

Stock Incentive Plan

Each of 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 the Stock Incentive Plan as of December 31, 2015. 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 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.

Restricted stock and restricted stock units granted to a named executive officer under the Stock 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 and restricted stock units are forfeited to us for no consideration, except that, if a named executive officer retires, his awards will continue to vest on the third anniversary of the date of grant if, from the date of his retirement through the third anniversary 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) the liquidation or dissolution of us or the approval by the limited partners of the Partnership of a plan of complete liquidation of the Partnership; (iii) 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 Warburg Pincus LLC or any other Affiliate; (iv) 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 Warburg Pincus LLC, the General Partner, or any other Affiliate; (v) a transaction resulting in a person other than Targa Resources GP LLC or an Affiliate being the General Partner of the Partnership; or (vi) 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 in the event there was a Change in Control or their employment was terminated due to death or Disability, each as of December 31, 2015. The amounts reported below assume that the price per share of our common stock was $27.06, which was the closing price per share of our common stock on December 31, 2015. No amounts are reported assuming retirement as of December 31, 2015, 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	$ 633,813(1)	$ 633,813(1)
Matthew J. Meloy	205,195(2)	205,195(2)
Michael A. Heim	444,039(3)	444,039(3)
Jeffrey J. McParland	293,654(4)	293,654(4)
Paul W. Chung	287,369(5)	287,369(5)

(1) Of the amount reported under each of the "Change in Control" column and the "Termination for Death or Disability" column: (a) $132,459 and $39,760, respectively, relate to the restricted shares and related dividend rights granted on January 15, 2013, which vested on January 15, 2016; (b) $130,510 and $29,264, respectively, relate to the restricted stock units and related dividend rights granted on January 14, 2014, which are scheduled to vest January 14, 2017; and (c) $268,219 and $33,602, respectively, relate to the restricted stock units and related dividend rights granted on January 15, 2015, which are scheduled to vest January 15, 2018.

(2) Of the amount reported under each of the "Change in Control" column and the "Termination for Death or Disability" column: (a) $47,139 and $14,149, respectively, relate to the restricted shares and related dividend rights granted on January 15, 2013, which vested on January 15, 2016; (b) $43,702 and $9,799, respectively, relate to the restricted stock units and related dividend rights granted on January 14, 2014, which are scheduled to vest January 14, 2017; and (c) $80,341 and $10,065, respectively, relate to the restricted stock units and related dividend rights granted on January 15, 2015, which are scheduled to vest January 15, 2018.

(3) Of the amount reported under each of the "Change in Control" column and the "Termination for Death or Disability" column: (a) $116,250 and $34,894, respectively, relate to the restricted shares and related dividend rights granted on January 15, 2013, which vested on January 15, 2016; (b) $93,519 and $20,969, respectively, relate to the restricted stock units and related dividend rights granted on January 14, 2014, which are scheduled to vest January 14, 2017; and (c) $158,545 and $19,862, respectively, relate to the restricted stock units and related dividend rights granted on January 15, 2015, which are scheduled to vest January 15, 2018.

(4) Of the amount reported under each of the "Change in Control" column and the "Termination for Death or Disability" column: (a) $75,930 and $22,792, respectively, relate to the restricted shares and related dividend rights granted on January 15, 2013, which vested on January 15, 2016; (b) $62,076 and $13,919, respectively, relate to the restricted stock units and related dividend rights granted on January 14, 2014, which are scheduled to vest January 14, 2017; and (c) $105,696 and $13,241, respectively, relate to the restricted stock units and related dividend rights granted on January 15, 2015, which are scheduled to vest January 15, 2018.

(5) Of the amount reported under each of the "Change in Control" column and the "Termination for Death or Disability" column: (a) $74,171 and $22,264, respectively, relate to the restricted shares and related dividend rights granted on January 15, 2013, which vested on January 15, 2016; (b) $60,750 and $13,622, respectively, relate to the restricted stock units and related dividend rights granted on January 14, 2014, which are scheduled to vest January 14, 2017; and (c) $103,586 and $12,977, respectively, relate to the restricted stock units and related dividend rights granted on January 15, 2015, which are scheduled to vest January 15, 2018.

Partnership's Long-Term Incentive Plan

Each of our named executive officers held outstanding performance unit awards under the Partnership's form of performance unit grant agreement (the "Performance Unit Agreement") and the Partnership's Long-Term Incentive Plan as of December 31, 2015. If a "Change in Control" occurred during the performance period established for the performance units and related distribution rights granted to a named executive officer under the Performance Unit Agreements, the performance units would be settled upon the occurrence of the Change in Control by providing the named executive officer with a number of common units of the Partnership equal to the target number of performance units granted to the named executive officer plus a cash payment in the amount of distribution equivalent rights then credited to the named executive officer, if any; provided the named executive officer (i) remained continuously employed by us from the date of grant to the date upon which such Change in Control occurred 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). The General Partner could elect to settle the performance unit awards in cash instead of in common units.

Generally, performance units and the related distribution equivalent rights granted to a named executive officer under a Performance Unit 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 performance period, he would become vested in the performance units that he is otherwise qualified to receive payment for based on achievement of the performance goal at the end of the performance period 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 distribution equivalent rights that would have accrued through the end of the performance period.

The following terms generally have the meanings specified below for purposes of the Partnership's Long-Term Incentive 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 Partnership or the General Partner, (ii) the limited partners of the Partnership approve a plan of complete liquidation of the Partnership, (iii) the sale or other 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 the General Partner or one of the General Partner's affiliates, or (iv) a transaction resulting in a person other than Targa Resources GP LLC or one of its affiliates being the General Partner of the Partnership.

- *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 Long-Term Incentive Plan and the Performance Unit Agreement.

- *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 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), 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.

The following table reflects amounts that would have been received by each of the named executive officers under the Partnership's Long-Term Incentive Plan and related Performance Unit Agreements in the event there was a Change in Control (in which case the performance percentage is deemed to be 100%) or their employment was terminated due to death or Disability or by us without Cause, each as of December 31, 2015. No amounts are reported assuming retirement as of December 31, 2015, since additional conditions must be met following a named executive officer's retirement in order for any performance unit awards to become vested. The amounts reported below assume that the price per Partnership common unit was $16.53, which was the closing price per common unit on December 31, 2015. In addition, the amounts reported below in the "Termination for Death or Disability or Without Cause" column assume that the applicable performance period for each award ended December 31, 2015 and are based on the target number of performance units held by the named executive officers as of December 31, 2015, multiplied by a performance percentage of 100%, which reflects the level at which outstanding performance unit awards were converted and restated into comparable awards based on the Company's common shares upon completion of the Buy-In Transaction in February 2016; however, the distribution amounts reported in this column are calculated through the end of the actual applicable performance period assuming the distribution level in effect as of December 31, 2015.

Name	Change in Control	Termination for Death or Disability or Without Cause
Joe Bob Perkins	$ 1,618,876(1)	$ 1,927,137(1)
Matthew J. Meloy	532,174(2)	629,294(2)
Michael A. Heim	1,168,878(3)	1,370,634(3)
Jeffrey J. McParland	772,185(4)	906,166(4)
Paul W. Chung	755,447(5)	886,634(5)

(1) Of the amount reported under the "Change in Control" column: (a) $346,651 and $163,888, respectively, relate to the performance units and related distribution equivalent rights granted on January 15, 2013; (b) $404,621 and $118,902, respectively, relate to the performance units and related distribution equivalent rights granted on January 14, 2014; and (c) $531,737 and $53,077, respectively, relate to the performance units and related distribution equivalent rights granted on January 21, 2015. Of the amount reported under the "Termination for Death or Disability or Without Cause" column: (a) $346,651 and $193,021, respectively, relate to the performance units and related distribution equivalent rights granted on January 15, 2013; (b) $404,621 and $208,149, respectively, relate to the performance units and related distribution equivalent rights granted on January 14, 2014; and (c) $531,737 and $242,958, respectively, relate to the performance units and related distribution equivalent rights granted on January 21, 2015.

(2) Of the amount reported under the "Change in Control" column: (a) $123,396 and $58,339, respectively, relate to the performance units and related distribution equivalent rights granted on January 15, 2013; (b) $135,480 and $39,812, respectively, relate to the performance units and related distribution equivalent rights granted on January 14, 2014; and (c) $159,250 and $15,896, respectively, relate to the performance units and related distribution equivalent rights granted on January 21, 2015. Of the amount reported under the "Termination for Death or Disability or Without Cause" column: (a) $123,396 and $68,709, respectively, relate to the performance units and related distribution equivalent rights granted on January 15, 2013; (b) $135,480 and $69,695, respectively, relate to the performance units and related distribution equivalent rights granted on January 14, 2014; and (c) $159,250 and $72,764, respectively, relate to the performance units and related distribution equivalent rights granted on January 21, 2015.

(3) Of the amount reported under the "Change in Control" column: (a) $304,235 and $143,835, respectively, relate to the performance units and related distribution equivalent rights granted on January 15, 2013; (b) $289,920 and $85,196, respectively, relate to the performance units and related distribution equivalent rights granted on January 14, 2014; and (c) $314,318 and $31,375, respectively, relate to the performance units and related distribution equivalent rights granted on January 21, 2015. Of the amount reported under the "Termination for Death or Disability or Without Cause" column: (a) $304,235 and $169,403, respectively, relate to the performance units and related distribution equivalent rights granted on January 15, 2013; (b) $289,920 and $149,143, respectively, relate to the performance units and related distribution equivalent rights granted on January 14, 2014; and (c) $314,318 and $143,616, respectively, relate to the performance units and related distribution equivalent rights granted on January 21, 2015.

(4) Of the amount reported under the "Change in Control" column: (a) $198,757 and $93,968, respectively, relate to the performance units and related distribution equivalent rights granted on January 15, 2013; (b) $192,442 and $56,551, respectively, relate to the performance units and related distribution equivalent rights granted on January 14, 2014; and (c) $209,551 and $20,917, respectively, relate to the performance units and related distribution equivalent rights granted on January 21, 2015. Of the amount reported under the "Termination for Death or Disability or Without Cause" column: (a) $198,757 and $110,671, respectively, relate to the performance units and related distribution equivalent rights granted on January 15, 2013; (b) $192,442 and $98,998, respectively, relate to the performance units and related distribution equivalent rights granted on January 14, 2014; and (c) $209,551 and $95,747, respectively, relate to the performance units and related distribution equivalent rights granted on January 21, 2015.

(5) Of the amount reported under the "Change in Control" column: (a) $194,128 and $91,779, respectively, relate to the performance units and related distribution equivalent rights granted on January 15, 2013; (b) $188,343 and $55,346, respectively, relate to the performance units and related distribution equivalent rights granted on January 14, 2014; and (c) $205,352 and $20,498, respectively, relate to the performance units and related distribution equivalent rights granted on January 21, 2015. Of the amount reported under the "Termination for Death or Disability or Without Cause" column: (a) $194,128 and $108,094, respectively, relate to the performance units and related distribution equivalent rights granted on January 15, 2013; (b) $188,343 and $96,889, respectively, relate to the performance units and related distribution equivalent rights granted on January 14, 2014; and (c) $205,352 and $93,828, respectively, relate to the performance units and related distribution equivalent rights granted on January 21, 2015.

Director Compensation

The following table sets forth the compensation earned by our non-employee directors for 2015:

Name	Fees Earned or Paid in Cash	Stock Awards (1)	Total Compensation
Robert B. Evans	$ 159,083	$ 94,377	$ 253,460
Barry R. Pearl	163,000	94,377	257,377
William D. Sullivan (2)	61,500	94,377	155,877
Ruth I. Dreessen	144,500	94,377	238,877
Rene R. Joyce	92,500	94,377	186,877

(1) Amounts represent the aggregate grant date fair value of fully vested Partnership common units awarded to the independent directors in 2015, 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 of common unit awards contained in the Notes to Consolidated Financial Statements at Note 22 included in our Annual Report on Form 10-K for the year ended December 31, 2015. On January 21, 2015, each director listed in the table above received 2,113 fully vested Partnership common units in connection with their 2015 service on the Board of Directors of the General Partner. The grant date fair value of each common unit computed in accordance with FASB ASC Topic 718 was $44.665, based on the average of the high and low price of the common units on the date of grant.

(2) Mr. Sullivan resigned effective May 18, 2015.

Narrative to Director Compensation Table

For 2015, each of the General Partner's independent directors received an annual cash retainer of $76,000, which was an increase over the annual cash retainer for 2014 of $61,000. The Chairman of the General Partner's Audit Committee received an additional annual retainer of $20,000, and the Chairman of the Conflicts Committee received an additional monthly retainer of (i) $20,000, beginning September 17, 2015 and continuing until public announcement of the Buy-In Transaction, and (ii) $7,500, beginning on the first day of the month following public announcement of the Buy-In Transaction and continuing until the closing date of the Buy-In Transaction. In addition, each member of the Conflicts Committee (other than the Chairman) received an additional monthly retainer of (i) $15,000, beginning September 17, 2015 and continuing until public announcement of the Buy-In Transaction, and (ii) $5,000, beginning on the first day of the month following public announcement of the Buy-In Transaction and continuing until the closing date of the Buy-In Transaction. All of the General Partner's independent directors receive $1,500 for each Board and Audit Committee and meeting attended. Payment of independent director fees is generally made twice annually, at the second regularly scheduled meeting of the General Partner's Board and at the final regularly scheduled meeting of the General Partner's Board for the fiscal year. All independent directors are reimbursed for out-of-pocket expenses incurred in attending General Partner's Board and committee meetings.

A director who is also an employee receives no additional compensation for services as a director. Accordingly, the Summary Compensation Table reflects total compensation received by Messrs. Perkins and Heim for all services performed for the General Partner and its affiliates during 2015.

Director Long-term Equity Incentives. The General Partner granted equity-based awards in January 2015 to the General Partner's independent directors under the Partnership's Long-Term Incentive Plan. Each of these directors received an award of 2,113 Partnership common units, which reflected the General Partner's intent to provide them with a target value of approximately $100,000 in annual long-term incentive awards, which was an increase over the target value for 2014 of $90,000. The awards are intended to align the long-term interests of the General Partner's directors with those of our unitholders.

Changes for 2016

The General Partner's Board did not make any changes to the compensation program for its independent directors for 2016. In January 2016, the General Partner's Board approved our independent director compensation for the 2016 fiscal year by maintaining the annual cash retainer for service on the General Partner's Board of $76,000 per year.

Director Long-term Equity Incentives. In January 2016, each of the General Partner's independent directors received an award of 6,698 fully vested Partnership common units under the Partnership's Long-Term Incentive Plan, which reflects the General Partner's desire to maintain the target value of the annual awards of approximately $100,000 per year.

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

The following table sets forth the beneficial ownership of our common units and of Targa common stock, as applicable, as of February 22, 2016 (unless otherwise indicated) held by:

- each person who then beneficially owns 5% or more of the then outstanding common units;
- all of the directors of Targa Resources GP LLC;
- each named executive officer of Targa Resources GP LLC; and
- all directors and executive officers of Targa Resources GP LLC as a group.

As a result of the TRC/TRP Merger, which was completed on February 17, 2016, Targa owns all of our outstanding common units. The following table reflects the shares of Targa common stock that the above persons received as merger consideration in connection with the TRC/TRP Merger, if applicable.

Beneficial ownership is determined under the rules of the Securities and Exchange Commission. 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 unitholders and 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 unitholder listed in the table below are based on 160,563,467 shares of Targa's common stock on February 22, 2016.

	Targa Resources Partners LP		Targa Resources Corp.	
Name of Beneficial Owner (1)	**Common Units Beneficially Owned**	**Percentage of Common Units Beneficially Owned**	**Common Stock Beneficially Owned**	**Percentage of Common Stock Beneficially Owned**
Targa Resources Corp.	184,899,602	100%	-	-
Rene R. Joyce (2)		-	1,115,598	*
Joe Bob Perkins (3)		-	667,376	*
Michael A. Heim (4)		-	584,396	*
Jeffrey J. McParland (5)		-	411,915	*
James W. Whalen (6)		-	707,310	*
Matthew J. Meloy		-	95,485	*
Paul W. Chung (7)		-	578,499	*
Barry R. Pearl		-	18,200	*
Robert B. Evans		-	26,632	*
Ruth I. Dreessen		-	9,727	*
All directors and executive officers as a group (15 persons)		-	4,511,288	2.8%

* Less than 1%

(1) Unless otherwise indicated, the address for all beneficial owners in this table is 1000 Louisiana, Suite 4300, Houston, Texas 77002 and the nature of the beneficial ownership for all the equity securities is sole voting and investment power.

(2) 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.

(3) Shares of common stock beneficially owned by Mr. Perkins include 307,370 shares issued to the Perkins Blue House Investments Limited Partnership ("PBHILP"). 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. Heim include: (i) 157,378 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) 101,672 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) 63,973 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) 42,000 shares issued to the Heim 2012 Children's Trust, of which Mr. Heim serves as trustee; and (v) 21,972 shares held by Mr. Heim's wife of which Mr. Heim and his wife have shared voting and investment power.

(5) Shares of common stock beneficially owned by Mr. McParland include 313,048 shares issued to the Sarah McParland Family Trust, of which Mr. McParland's spouse serves as trustee.

(6) Shares of common stock beneficially owned by Mr. Whalen include (i) 420,999 shares issued to the Whalen Family Investments Limited Partnership and (ii) 98,000 issued to the Whalen Family Investments Limited Partnership 2.

(7) Shares of common stock beneficially owned by Mr. Chung include (i) 189,904 shares issued to the Paul Chung 2008 Family Trust, of which Mr. Chung serves as trustee, (ii) 189,904 shares issued to the Helen Chung 2007 Family Trust, of which Mr. Chung's spouse and Mr. Chung's sister-in-law serve as co-trustees.

Securities Authorized for Issuance under Equity Compensation Plans

The following table sets forth certain information as of December 31, 2015 regarding our long-term incentive plan, called the Targa Resources Long-Term Incentive Plan (the "LTIP"), under which our common units are authorized for issuance to employees, consultants and directors who provide services to us. The LTIP is the sole equity compensation plan under which previously granted options, warrants or rights remain outstanding or under which we may make equity grants in the future. The LTIP was approved by our partners prior to our initial public offering.

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (1)	Weighted average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))(2)
	(a)	(b)	(c)
Equity compensation plans approved by security holders	675,745	-	553,927
Total	675,745	-	553,927

(1) Represents units subject to equity-settled performance unit awards granted under the LTIP, assuming the target distribution at the time of vesting. Payment with respect to the outstanding equity-settled performance unit awards may range from 0% to 150% of the target distribution depending on performance actually attained, with a maximum number of 830,890 units shown in column (a) being potentially issuable under the LTIP. There is no exercise price applicable to these awards.

(2) Includes units that may be issued in payment of the outstanding equity-settled performance unit awards reported in column (a) if and to the extent such payment exceeds the target distribution amount reported in column (a) with respect to such awards

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

As of February 15, 2016, Targa owned 16,309,594 common units representing an aggregate 8.8% limited partner interest in us. In addition, our general partner owns a 2% general partner interest in us, the incentive distribution rights and the Special GP Interest. As a result of the TRC/TRP Merger, which was completed on February 17, 2016, TRC owns all of the outstanding TRP common units.

Distributions and Payments to Our General Partner and its Affiliates

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

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

Partnership Agreement

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

Reimbursement of Operating and General and Administrative Expense

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

Competition

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

Indemnification Agreements

Indemnification Agreements with Targa

Targa has agreed to indemnify us for losses relating to income tax liabilities attributable to pre-IPO operations that are not reserved on the books of the Predecessor Business of the North Texas System as of February 14, 2007. Targa does not have any obligation under this indemnification until our aggregate losses exceed $250,000. Targa's obligation under this indemnification will terminate upon the expiration of any applicable statute of limitations. We will indemnify Targa for all losses attributable to the post-IPO operations of the North Texas System.

Indemnification Agreements with Directors and Officers

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

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

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

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

Transactions with Related Persons

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. Targa provides general and administrative services to Sajet and is reimbursed for these amounts at its actual cost. Services provided to Sajet totaled $1.1 million in 2015.

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"). Targa provides general and administrative services to Tesla and Floridian and is reimbursed for these amounts at its actual cost. Services provided to Tesla and Floridian totaled $0.2 million for such services provided.

Relationship with Total Safety US Inc.

Joe Bob Perkins, Chief Executive Officer of our general partner, is also a member of the Board of Managers of W3 Holdings, LLC, parent company of Total Safety US Inc. ("Total Safety") which provides us safety services and equipment, including detection and monitoring systems. During 2015, we made payments of $0.1 million to Total Safety.

Relationships with Legacy Reserves LP, SM Energy Company and Compressor Systems Inc.

William D. Sullivan, one of our former directors of our general partner, is also a director of Legacy Reserves LP ("Legacy"), SM Energy Company ("SM Energy") and Compressor Systems Inc ("Compressor"). During 2015, we transacted purchases of $6.2 million with Legacy, $4.4 million with SM Energy and $9.6 million with Compressor. We also transacted sales of $22.1 million with SM Energy during 2015.

Relationship with Magellan Asset Services LP

Barry Pearl, a director of our general partner, is also a director of Magellan Midstream Partners, L.P., parent company of Magellan Asset Services LP ("Magellan"). During 2015, we transacted sales of $25.6 million with Magellan.

Relationship with Kansas Gas Service

Robert Evans, a director of our general partner, is also a director of ONE Gas, Inc. ("ONE"). We have commercial arrangements with Kansas Gas Service ("Kansas Gas"), a division of ONE. During 2015, we transacted sales of $11.5 million with Kansas Gas.

Conflicts of Interest

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

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

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

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

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

Review, Approval or Ratification of Transactions with Related Persons

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

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

Director Independence

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

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

Item 14. Principal Accounting Fees and Services.

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

	2015	2014
	(In millions)	
Audit fees (1)	$ 3.7	$ 2.9
Audit related fees (2)	-	-
Tax fees (3)	0.5	-
All other fees (4)	-	-
	$ 4.2	$ 2.9

(1) Audit fees represent amounts billed for each of the years presented for professional services rendered in connection with (i) the integrated audit of our annual financial statements and internal control over financial reporting, (ii) the review of our quarterly financial statements or (iii) those services normally provided in connection with statutory and regulatory filings or engagements including comfort letters, consents and other services related to SEC matters. This information is presented as of the latest practicable date for this Annual Report.

(2) Audit related fees represent amounts we were billed in each of the years presented for assurance and related services that are reasonably related to the performance of the annual audit or quarterly reviews of our financial statements and are not reported under audit fees.

(3) Tax fees represent amounts we were billed in each of the years presented for professional services rendered in connection with tax compliance.

(4) All other fees represent amounts we were billed in each of the years presented for services not classifiable under the other categories listed in the table above. No such services were rendered by PricewaterhouseCoopers LLP during the last two years.

All services provided by our independent principal accountant are subject to pre-approval by the audit committee of our general partner. The audit committee of our general partner is informed of each engagement of the independent principal accountant to provide services under the policy. The audit committee of our general partner has approved the use of PricewaterhouseCoopers LLP as our independent principal accountant.

PART IV

Item 15. Exhibits, Financial Statement Schedules.

(a)(1) Financial Statements

Our Consolidated Financial Statements are included under Part II, Item 8 of the Annual Report. For a listing of these statements and accompanying footnotes, see “Index to Consolidated Financial Statements” on Page F-1 in this Annual Report.

(a)(2) Financial Statement Schedules

All schedules have been omitted because they are either not applicable, not required or the information called for therein appears in the consolidated financial statements or notes thereto.

(a)(3) Exhibits

Number	Description
2.1***	Purchase and Sale Agreement, dated September 18, 2007, by and between Targa Resources Holdings LP and Targa Resources Partners LP (incorporated by reference to Exhibit 2.1 to Targa Resources Partners LP’s Current Report on Form 8-K filed September 21, 2007 (File No. 001-33303)).
2.2	Amendment to Purchase and Sale Agreement, dated October 1, 2007, by and between Targa Resources Holdings LP and Targa Resources Partners LP (incorporated by reference to Exhibit 2.2 to Targa Resources Partners LP’s Current Report on Form 8-K filed October 24, 2007 (File No. 001-33303)).
2.3	Purchase and Sale Agreement dated July 27, 2009, by and between Targa Resources Partners LP, Targa GP Inc. and Targa LP Inc. (incorporated by reference to Exhibit 2.1 to Targa Resources Partners LP’s Current Report on Form 8-K filed July 29, 2009 (File No. 001-33303)).
2.4	Purchase and Sale Agreement, dated March 31, 2010, by and among Targa Resources Partners LP, Targa LP Inc., Targa Permian GP LLC and Targa Midstream Holdings LLC (incorporated by reference to Exhibit 2.1 to Targa Resources Partners LP’s Current Report on Form 8-K filed April 1, 2010 (File No. 001-33303)).
2.5	Purchase and Sale Agreement, dated August 6, 2010, by and between Targa Resources Partners LP and Targa Versado Holdings LP (incorporated by reference to Exhibit 2.1 to Targa Resources Partners LP’s Current Report on Form 8-K filed August 9, 2010 (File No. 001-33303)).
2.6	Purchase and Sale Agreement, dated September 13, 2010, by and between Targa Resources Partners LP and Targa Versado Holdings LP (incorporated by reference to Exhibit 2.1 to Targa Resources Partners LP’s Current Report on Form 8-K filed September 17, 2010 (File No. 001-33303)).
2.7***	Membership Interest Purchase and Sale Agreement, dated November 14, 2012, by and among Targa Resources Partners LP, Saddle Butte Pipeline LLC, Saddle Butte Fort Berthold Gathering, LLC and Saddle Butte Assets, LLC (incorporated by reference to Exhibit 2.1 to Targa Resources Partners LP’s Current Report on Form 8-K filed November 15, 2012 (File No. 001-33303)).
2.8***	Agreement and Plan of Merger, by and among Targa Resources Corp., Trident GP Merger Sub LLC, Atlas Energy, L.P. and Atlas Energy GP, LLC, dated October 13, 2014 (incorporated by reference to Exhibit 2.1 to Targa Resources Partners LP’s Current Report on Form 8-K filed October 17, 2014 (File No. 001-33303)).
2.9***	Agreement and Plan of Merger, by and among Targa Resources Corp., Targa Resources Partners LP, Targa Resources GP LLC, Trident MLP Merger Sub LLC, Atlas Energy, L.P., Atlas Pipeline Partners, L.P. and Atlas Pipeline Partners GP, LLC, dated October 13, 2014 (incorporated by reference to Exhibit 2.2 to Targa Resources Partners LP’s Current Report on Form 8-K filed October 17, 2014 (File No. 001-33303)).

2.10***	Agreement and Plan of Merger, dated as of November 2, 2015, by and among Targa Resources Corp., Spartan Merger Sub LLC, Targa Resources Partners LP and Targa Resources GP LLC (incorporated by reference to Exhibit 2.1 to Targa Resources Partners LP's Current Report on Form 8-K filed November 6, 2015 (File No. 001-33303)).
3.1	Certificate of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.2 to Targa Resources Partners LP's Registration Statement on Form S-1 filed November 16, 2006 (File No. 333-138747)).
3.2	Certificate of Formation of Targa Resources GP LLC (incorporated by reference to Exhibit 3.3 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed January 19, 2007 (File No. 333-138747)).
3.3	Second Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.1 to Targa Resources Partners LP's Current Report on Form 8-K filed October 15, 2015 (File No. 001-33303)).
3.4	Limited Liability Company Agreement of Targa Resources GP LLC (incorporated by reference to Exhibit 3.4 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed January 19, 2007 (File No. 333-138747)).
4.1	Specimen Unit Certificate representing common units (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP's Annual Report on Form 10-K filed April 2, 2007 (File No. 001-33303)).
4.2	Indenture dated February 2, 2011 among the Issuers, the Guarantors and U.S. Bank National Association, as trustee thereto (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP's Current Report on Form 8-K filed February 2, 2011 (File No. 001-33303)).
4.3	Registration Rights Agreement dated February 2, 2011 among the Issuers, the Guarantors, Deutsche Bank Securities Inc., as representative of the several initial purchasers, and the Dealer Managers (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP's Current Report on Form 8-K filed February 3, 2011 (File No. 001-33303)).
4.4	Supplemental Indenture dated April 8, 2011 to Indenture dated February 2, 2011, among Targa Terminals LLC, a subsidiary of 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 6, 2011 (File No. 001-33303)).
4.5	Supplemental Indenture dated October 28, 2011 to Indenture dated February 2, 2011, among Targa Gas Processing LLC, Targa Sound Terminal LLC and Sound Pipeline Company, LLC, subsidiaries of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.3 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed November 7, 2011 (File No. 001-33303)).
4.6	Supplemental Indenture dated April 20, 2012 to Indenture dated February 2, 2011, among Targa Cogen LLC, a subsidiary of 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 August 6, 2012 (File No. 001-33303)).
4.7	Supplemental Indenture dated February 14, 2013 to Indenture dated February 2, 2011, among Targa Badlands LLC, Targa Assets LLC and Targa Fort Berthold Gathering LLC, subsidiaries of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.66 to Targa Resources Partners LP's Annual Report on Form 10-K filed February 19, 2013 (File No. 001-33303)).

4.8	Indenture dated as of January 31, 2012 among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors named therein and U.S. Bank National Association (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP's Current Report on Form 8-K filed January 31, 2012 (File No. 001-33303)).
4.9	Registration Rights Agreement dated as of January 31, 2012 among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors named therein and the initial purchasers named therein (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP's Current Report on Form 8-K filed January 31, 2012 (File No. 001-33303)).
4.10	Supplemental Indenture dated April 20, 2012 to Indenture dated January 31, 2012, among Targa Cogen LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.4 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed August 6, 2012 (File No. 001-33303)).
4.11	Supplemental Indenture dated February 14, 2013 to Indenture dated January 31, 2012, among Targa Badlands LLC, Targa Assets LLC and Targa Fort Berthold Gathering LLC, subsidiaries of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.70 to Targa Resources Partners LP's Annual Report on Form 10-K filed February 19, 2013 (File No. 001-33303)).
4.12	Indenture dated as of October 25, 2012 among Targa Resources Partners LP, Targa Resources Partners Finance Corporation and the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP's Current Report on Form 8-K filed October 26, 2012 (File No. 001-33303)).
4.13	Registration Rights Agreement dated as of October 25, 2012 among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors and Merrill Lynch, Pierce, Fenner & Smith Incorporated, Deutsche Bank Securities Inc., Wells Fargo Securities, LLC, Barclays Capital Inc. and RBS Securities Inc., as representatives of the several initial purchasers (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP's Current Report on Form 8-K filed October 26, 2012 (File No. 001-33303)).
4.14	Supplemental Indenture dated February 14, 2013 to Indenture dated October 25, 2012, among Targa Badlands LLC, Targa Assets LLC and Targa Fort Berthold Gathering LLC, subsidiaries of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.73 to Targa Resources Partners LP's Annual Report on Form 10-K filed February 19, 2013 (File No. 001-33303)).
4.15	Registration Rights Agreement dated as of December 10, 2012 among the Issuers, the Guarantors and Merrill Lynch, Pierce, Fenner & Smith Incorporated, Deutsche Bank Securities Inc., Wells Fargo Securities, LLC, Barclays Capital Inc. and RBS Securities Inc., as representatives of the several initial purchasers. (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP's Current Report on Form 8-K filed December 10, 2012 (File No. 001-33303)).
4.16	Indenture dated as of May 14, 2013 among the Issuers and the Guarantors and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP's Current Report on Form 8-K filed May 14, 2013 (File No. 001-33303)).
4.17	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, 2012 (File No. 001-33303)).

4.18	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)).
4.19	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)).
4.20	Indenture dated as of January 30, 2015 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 8-K filed January 30, 2014 (File No. 001-33303)).
4.21	Registration Rights Agreement dated as of January 30, 2015 among the Issuers, the Guarantors and Merrill Lynch, Pierce, Fenner & Smith Incorporated, Barclays Capital Inc., J.P. Morgan Securities LLC, Morgan Stanley & Co. LLC 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 8-K filed January 30, 2014 (File No. 001-33303)).
4.22	Indenture, dated as of May 11, 2015, among Targa Resources Partners LP, Targa Resources Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP's Current Report on Form 8-K filed May 12, 2015 (File No. 001-33303)).
4.23	Registration Rights Agreement, dated as of May 11, 2015, among Targa Resources Partners LP, Targa Resources Finance Corporation, the Guarantors named therein and Barclays Capital Inc., as dealer manager (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP's Current Report on Form 8-K filed May 12, 2015 (File No. 001-33303)).
4.24	Indenture, dated as of September 14, 2015, among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP's Current Report on Form 8-K filed September 15, 2015 (File No. 001-33303)).
4.25	Registration Rights Agreement, dated as of September 14, 2015, among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors named therein and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as representative of the several initial purchasers (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP's Current Report on Form 8-K filed September 15, 2015 (File No. 001-33303)).
4.26	Specimen Unit Certificate for the Series A Preferred Units (attached as Exhibit B to the Second Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP and incorporated by reference to Exhibit 3.1 to Targa Resources Partners LP's Current Report on Form 8-K filed October 15, 2015 (File No. 001-33303)).
10.1	Second Amended and Restated Credit Agreement, dated October 3, 2012, by and among Targa Resources Partners LP, Bank of America, N.A. and the other parties signatory thereto (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed October 9, 2012 (File No. 001-33303)).
10.2	First Amendment, Waiver and Incremental Commitment Agreement, dated as of February 23, 2015, to the Second Amended and Restated Credit Agreement, by and among Targa Resources Partners LP, Bank of America, N.A. and the other parties signatory thereto (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed February 26, 2015 (File No. 001-33303)).

10.3	Contribution, Conveyance and Assumption Agreement, dated February 14, 2007, by and among Targa Resources Partners LP, Targa Resources Operating LP, Targa Resources GP LLC, Targa Resources Operating GP LLC, Targa GP Inc., Targa LP Inc., Targa Regulated Holdings LLC, Targa North Texas GP LLC and Targa North Texas LP (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP's Current Report on Form 8-K filed February 16, 2007 (File No. 001-33303)).
10.4	Contribution, Conveyance and Assumption Agreement, dated October 24, 2007, by and among Targa Resources Partners LP, Targa Resources Holdings LP, Targa TX LLC, Targa TX PS LP, Targa LA LLC, Targa LA PS LP and Targa North Texas GP LLC (incorporated by reference to Exhibit 10.4 to Targa Resources Partners LP's Current Report on Form 8-K filed October 24, 2007 (File No. 001-33303)).
10.5	Contribution, Conveyance and Assumption Agreement, dated September 24, 2009, by and among Targa Resources Partners LP, Targa GP Inc., Targa LP Inc., Targa Resources Operating LP and Targa North Texas GP LLC (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed September 24, 2009 (File No. 001-33303)).
10.6	Contribution, Conveyance and Assumption Agreement, dated April 27, 2010, by and among Targa Resources Partners LP, Targa LP Inc., Targa Permian GP LLC, Targa Midstream Holdings LLC, Targa Resources Operating LP, Targa North Texas GP LLC and Targa Resources Texas GP LLC (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed April 29, 2010 (File No. 001-33303)).
10.7	Contribution, Conveyance and Assumption Agreement, dated August 25, 2010, by and among Targa Resources Partners LP, Targa Versado Holdings LP and Targa North Texas GP LLC (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed August 26, 2010 (File No. 001-33303)).
10.8	Contribution, Conveyance and Assumption Agreement, dated September 28, 2010, by and among Targa Resources Partners LP, Targa Versado Holdings LP and Targa North Texas GP LLC (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed October 4, 2010 (File No. 001-33303)).
10.9	Second Amended and Restated Omnibus Agreement, dated September 24, 2009, by and among Targa Resources Partners LP, Targa Resources, Inc., Targa Resources LLC and Targa Resources GP LLC (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP's Current Report on Form 8-K filed September 24, 2009 (File No. 001-33303)).
10.10	First Amendment to Second Amended and Restated Omnibus Agreement, dated April 27, 2010, by and among Targa Resources Partners LP, Targa Resources, Inc., Targa Resources LLC and Targa Resources GP LLC (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP's Current Report on Form 8-K filed April 29, 2010 (File No. 001-33303)).
10.11	Purchase Agreement dated as of October 23, 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 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed October 29, 2014 (File No. 001-33303)).
10.12	Purchase Agreement dated as of January 15, 2015 among the Issuers, the Guarantors and Merrill Lynch, Pierce, Fenner & Smith Incorporated, Barclays Capital Inc., RBS Securities Inc., Morgan Stanley & Co. LLC and J.P. Morgan Securities LLC, as representatives of the several initial purchasers (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on 8-K filed January 30, 2015 (File No. 001-33303)).
10.13	Third Supplemental Indenture, dated as of April 24, 2015, by and among Targa Pipeline Partners LP, Targa Pipeline Finance Corporation, the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed May 12, 2015 (File No. 001-33303)).

10.14	Purchase Agreement dated as of September 9, 2015 among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as representative of the several initial purchasers (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP’s Current Report on 8-K filed September 15, 2015 (File No. 001-33303)).
10.15	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)).
10.16	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)).
10.17	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)).
10.18	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)).
10.19+	Targa Resources Investments Inc. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.9 to Targa Resources Partners LP’s Registration Statement on Form S-1/A filed February 1, 2007 (File No. 333-138747)).
10.20+	First Amendment to the Targa Resources Investments Inc. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to Targa Resources Partners LP's Current Report on Form 8-K/A filed July 24, 2013 (File No. 001-33303)).
10.21+	Form of Targa Resources Corp. 2010 Stock Incentive Plan (incorporated by reference to Exhibit 10.93 of Targa Investment’s Inc.’s Registration Statement on Form S-1/A filed November 12, 2010 (File No. 333-169277)).
10.22+	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)).
10.23+	Amendment to Targa Resources Partners LP Long-Term Incentive Plan dated December 18, 2008 (incorporated by reference to Exhibit 10.10 to Targa Resources Partners LP’s Annual Report on Form 10-K filed February 27, 2009 (File No. 001-33303)).
10.24+	Form of Restricted Unit Grant Agreement – 2010 (incorporated by reference to Exhibit 10.15 to Targa Resources Partners LP’s Annual Report on Form 10-K filed March 4, 2010 (File No. 001-33303)).
10.25+	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)).

10.26+	Targa Resources Partners LP Performance Unit Grant Agreement under the Targa Resources Corp. Long-Term 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)).
10.27+	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 Corp. Amendment to Targa Resources Partners LP Outstanding Performance Units (incorporated by reference to Exhibit 10.5 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 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)).
10.30+	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)).
10.31+	Targa Resources Executive Officer Change In Control Severance Program (incorporated by reference to Exhibit 10.3 to Targa Resources Partners LP’s Current Report on Form 8-K filed January 19, 2012 ((File No. 001-33303)).
10.32+	First Amendment to the Targa Resources Executive Officer Change in Control Severance Program, dated December 3, 2015 (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP’s Current Report on Form 8-K filed December 8, 2015 ((File No. 001-33303)).
10.33	Gas Gathering and Purchase Agreement by and between Burlington Resources Oil & Gas Company LP, Burlington Resources Trading Inc. and Targa Midstream Services Limited Partnership (portions of this exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment) (incorporated by reference to Exhibit 10.5 to Targa Resources Partners LP’s Registration Statement on Form S-1/A filed February 8, 2007 (File No. 333-138747)).
10.34+	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)).
10.35+	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)).
10.36+	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)).
10.37+	Targa Resources Partners LP Indemnification Agreement for William D. Sullivan dated February 14, 2007 (incorporated by reference to Exhibit 10.13 to Targa Resources Partners LP’s Annual Report on Form 10-K filed April 2, 2007 (File No. 001-33303)).
10.38+	Targa Resources Partners LP Indemnification Agreement for Ruth I. Dreessen dated February 6, 2013 (incorporated by reference to Exhibit 10.44 to Targa Resources Partners LP’s Annual Report on Form 10-K filed February 19, 2013 (File No. 001-33303)).
10.39+	Indemnification Agreement by and between Targa Resources Corp. and D. Scott Pryor, dated November 12, 2015 (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP’s Current Report on Form 8-K filed November 16, 2015 (File No. 001-33303)).

10.40+	Indemnification Agreement by and between Targa Resources Corp. and Patrick J. McDonie, dated November 12, 2015 (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP's Current Report on Form 8-K filed November 16, 2015 (File No. 001-33303)).
10.41+	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 Partners LP's Current Report on Form 8-K filed November 16, 2015 (File No. 001-33303)).
10.42+	Indemnification Agreement by and between Targa Resources Corp. and Clark White, dated November 12, 2015 (incorporated by reference to Exhibit 10.4 to Targa Resources Partners LP's Current Report on Form 8-K filed November 16, 2015 (File No. 001-33303)).
21.1*	List of Subsidiaries of Targa Resources Partners LP.
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.
99.1***	First Amendment to Membership Interest Purchase and Sale Agreement, dated December 20, 2012, by and among the Partnership, Saddle Butte Pipeline LLC, Saddle Butte Fort Berthold Gathering, LLC and Saddle Butte Assets, LLC (incorporated by reference to Exhibit 99.1 to Targa Resources Partners LP's Current Report on Form 8-K filed January 4, 2013 (File No. 001-33303)).
101.INS*	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

**Furnishedherewith

*** 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

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Targa Resources Partners LP
(Registrant)

By: Targa Resources GP LLC,
its general partner

Date: February 29, 2016

By: */s/ Matthew J. Meloy*
Matthew J. Meloy
Executive Vice President and Chief Financial Officer
(Authorized Officer and 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 29, 2016.

Signature	Title (Position with Targa Resources GP LLC)
/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. Sparger John R. Sparger	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/ Rene R. Joyce Rene R. Joyce	Director
/s/ Barry R. Pearl Barry R. Pearl	Director
/s/ Robert B. Evans Robert B. Evans	Director
/s/ Ruth I. Dreessen Ruth I. Dreessen	Director

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

TARGA RESOURCES PARTNERS LP AUDITED CONSOLIDATED FINANCIAL STATEMENTS

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal control over financial reporting is a process that involves human diligence and compliance and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting also can be circumvented by collusion or improper management override. Because of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis by internal control over financial reporting. However, these inherent limitations are known features of the financial reporting process. Therefore, it is possible to design into the process safeguards to reduce, though not eliminate, this risk.

Management has used the framework set forth in the report entitled "Internal Control—Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") in 2013 to evaluate the effectiveness of the internal control over financial reporting. Based on that evaluation, management has concluded that the internal control over financial reporting was not effective as of December 31, 2015, as discussed in Item 9A.

The businesses of Atlas Pipeline Partners, L.P. which the Partnership purchased on February 27, 2015 and Atlas Energy, L.P. which Targa purchased on February 27, 2015 were excluded from the scope of our management's assessment of our internal control over financial reporting as of December 31, 2015. These businesses constituted 21.6% and 18.0% of total reportable segment revenue and operating margin for the year ended December 31, 2015 and 51.5% of total assets at December 31, 2015.

The effectiveness of our internal control over financial reporting as of December 31, 2015 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 Partners of Targa Resources Partners LP:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, of comprehensive income (loss), of changes in owners' equity and of cash flows present fairly, in all material respects, the financial position of Targa Resources Partners LP and its subsidiaries (the "Partnership") at December 31, 2015 and December 31, 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Partnership did not maintain, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) because a material weakness in internal control over financial reporting related to the development and application of inputs, assumptions and calculations used in certain cash flow-based fair value measurements such as those associated with business combinations and impairments existed as of that date. A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the annual or interim financial statements will not be prevented or detected on a timely basis. The material weakness referred to above is described in the accompanying Management's Report on Internal Control Over Financial Reporting. We considered this material weakness in determining the nature, timing, and extent of audit tests applied in our audit of the 2015 consolidated financial statements, and our opinion regarding the effectiveness of the Partnership's internal control over financial reporting does not affect our opinion on those consolidated financial statements. The Partnership's management is responsible for these 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 management's report referred to above. Our responsibility is to express opinions on these financial statements and on the Partnership's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. 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.

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.

As described in Management's Report on Internal Control Over Financial Reporting, management has excluded the businesses of Atlas Pipeline Partners, L.P. and Atlas Energy, L.P. (collectively, “Atlas”) from its assessment of internal control over financial reporting as of December 31, 2015 because they were acquired by the Partnership in a purchase business combination during 2015. We also have excluded the Atlas businesses from our audit of internal control over financial reporting. The Atlas businesses are consolidated by the Partnership and their revenue and operating margin represent approximately 21.6% and 18.0%, respectively, of reportable segment revenue and operating margin, and 51.5% of consolidated total assets of the Partnership as of and for the year ended December 31, 2015.

/s/PricewaterhouseCoopers LLP
Houston, Texas
February 29, 2016

PART I – FINANCIAL INFORMATION

Item 1. Financial Statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED BALANCE SHEETS

			December 31, 2015	December 31, 2014
			(In millions)	
ASSETS				
Current assets:				
Cash and cash equivalents			$ 135.4	$ 72.3
Trade receivables, net of allowances of $0.1 and $0.0 million at December 31, 2015 and December 31, 2014			514.8	566.8
Inventories			141.0	168.9
Assets from risk management activities			92.2	44.4
Other current assets			10.0	3.8
Total current assets			893.4	856.2
Property, plant and equipment			11,928.2	6,514.3
Accumulated depreciation			(2,225.6)	(1,689.7)
Property, plant and equipment, net			9,702.6	4,824.6
Intangible assets, net			1,810.1	591.9
Goodwill			417.0	-
Long-term assets from risk management activities			34.9	15.8
Investments in unconsolidated affiliates			258.9	50.2
Other long-term assets			48.1	38.5
Total assets			$ 13,165.0	$ 6,377.2
LIABILITIES AND OWNERS' EQUITY				
Current liabilities:				
Accounts payable and accrued liabilities			$ 635.8	$ 592.7
Accounts payable to Targa Resources Corp.			30.0	53.2
Liabilities from risk management activities			5.2	5.2
Accounts receivable securitization facility			219.3	182.8
Total current liabilities			890.3	833.9
Long-term debt			5,164.0	2,783.4
Long-term liabilities from risk management activities			2.4	-
Deferred income taxes, net			27.2	13.7
Other long-term liabilities			178.2	57.8
Contingencies (see Note 17)				
Owners' equity:				
Series A preferred limited partners	Issued	Outstanding		
December 31, 2015	5,000,000	5,000,000	120.6	-
Common limited partners	Issued	Outstanding	4,550.4	2,384.1
December 31, 2015	185,083,420	184,870,693		
December 31, 2014	118,652,798	118,586,056		
General partner			1,735.3	78.6
December 31, 2015	3,772,871	3,772,871		
December 31, 2014	2,420,124	2,420,124		
Receivables from unit issuances			-	(1.0)
Accumulated other comprehensive income (loss)			86.8	60.3
Treasury units at cost (212,727 units as of December 31, 2015, and 66,742 as of December 31, 2014)			(10.3)	(4.8)
			6,482.8	2,517.2
Noncontrolling interests in subsidiaries			420.1	171.2
Total owners' equity			6,902.9	2,688.4
Total liabilities and owners' equity			$ 13,165.0	$ 6,377.2

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2015	2014	2013
	(In millions, except per unit amounts)		
Revenues:			
Sales of commodities	$ 5,465.4	$ 7,595.2	$ 5,728.2
Fees from midstream services	1,193.2	1,021.3	586.7
Total revenues	6,658.6	8,616.5	6,314.9
Costs and expenses:			
Product purchases	4,873.0	7,046.9	5,137.2
Operating expenses	504.6	433.0	376.2
Depreciation and amortization expenses	677.1	346.5	271.6
General and administrative expenses	153.6	139.8	143.1
Provisional goodwill impairment	290.0	-	-
Other operating (income) expense	(7.1)	(3.0)	9.6
Income from operations	167.4	653.3	377.2
Other income (expense):			
Interest expense, net	(207.8)	(143.8)	(131.0)
Equity earnings (loss)	(2.5)	18.0	14.8
Gain (loss) from financing activities (see Note 9 – Debt Obligations)	2.8	(12.4)	(14.7)
Other	(18.6)	(5.2)	15.2
Income (loss) before income taxes	(58.7)	509.9	261.5
Income tax (expense) benefit:			
Current	(0.8)	(3.2)	(2.0)
Deferred	0.2	(1.6)	(0.9)
	(0.6)	(4.8)	(2.9)
Net income (loss)	(59.3)	505.1	258.6
Less: Net income (loss) attributable to noncontrolling interests	(31.9)	37.4	25.1
Net income (loss) attributable to Targa Resources Partners LP	$ (27.4)	$ 467.7	$ 233.5
Net income attributable to preferred limited partners	$ 2.4	$ -	$ -
Net income attributable to general partner	167.7	148.7	107.5
Net income (loss) attributable to common limited partners	(197.5)	319.0	126.0
Net income (loss) attributable to Targa Resources Partners LP	$ (27.4)	$ 467.7	$ 233.5
Net income (loss) per common limited partner unit - basic	$ (1.15)	$ 2.78	$ 1.19
Net income (loss) per common limited partner unit - diluted	$ (1.15)	$ 2.77	$ 1.19
Weighted average limited partner units outstanding - basic	172.3	114.7	105.5
Weighted average limited partner units outstanding - diluted	172.3	115.1	105.7

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Year Ended December 31,		
	2015	2014	2013
		(In millions)	
Net income (loss)	$ (59.3)	$ 505.1	$ 258.6
Other comprehensive income (loss):			
Commodity hedging contracts:			
Change in fair value	81.3	59.8	(5.8)
Settlements reclassified to revenues	(54.8)	4.2	(21.2)
Interest rate swaps:			
Settlements reclassified to interest expense, net	-	2.4	6.1
Other comprehensive income (loss)	26.5	66.4	(20.9)
Comprehensive income (loss)	(32.8)	571.5	237.7
Less: Comprehensive income attributable to noncontrolling interests	(31.9)	37.4	25.1
Comprehensive income attributable to Targa Resources Partners LP	$ (0.9)	$ 534.1	$ 212.6

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF CHANGES IN OWNERS' EQUITY

	Limited Partner		Limited Partner		General Partner		Receivables From Unit Issuances	Accumulated Other Comprehensive Income (Loss)	Treasury Units		Non-controlling Interests	Total
	Preferred	Amount	Common	Amount	Units	Amount			Units	Amount		
	(In millions, except units in thousands)											
Balance December 31, 2012	-	$ -	100,096	$1,649.5	2,043	$ 45.3	$ -	$ 14.8	-	$ -	$ 150.5	$1,860.1
Compensation on equity grants	-	-		6.0	-	-	-	-	-	-	-	6.0
Distribution equivalent rights	-	-	-	(1.7)	-	-	-	-	-	-	-	(1.7)
Issuance of common units under compensation program	-	-	13	-	-	-	-	-	-	-	-	-
Equity offerings	-	-	11,154	517.8	-	-	-	-	-	-	-	517.8
Contributions from Targa Resources Corp.	-	-	-	-	228	10.8	-	-	-	-	-	10.8
Distributions to noncontrolling interests	-	-	-	-	-	-	-	-	-	-	(19.3)	(19.3)
Contributions from noncontrolling interests	-	-	-	-	-	-	-	-	-	-	4.3	4.3
Other comprehensive income (loss)	-	-	-	-	-	-	-	(20.9)	-	-	-	(20.9)
Net income	-	-	-	126.0	-	107.5	-	-	-	-	25.1	258.6
Distributions	-	-	-	(295.7)	-	(101.6)	-	-	-	-	-	(397.3)
Balance December 31, 2013	-	$ -	111,263	$2,001.9	2,271	$ 62.0	$ -	$ (6.1)	-	$ -	$ 160.6	$2,218.4
Compensation on equity grants	-	-	-	9.2	-	-	-	-	-	-	-	9.2
Distribution equivalent rights	-	-	-	(1.4)	-	-	-	-	-	-	-	(1.4)
Issuance of common units under compensation program	-	-	215	-	-	-	-	-	-	-	-	-
Units tendered for tax withholding obligations	-	-	(67)	-	-	-	-	-	67	(4.8)	-	(4.8)
Equity offerings	-	-	7,175	408.4	-	-	-	-	-	-	-	408.4
Contributions from Targa Resources Corp.	-	-	-	-	149	8.7	(1.0)	-	-	-	-	7.7
Distributions to noncontrolling interests	-	-	-	-	-	-	-	-	-	-	(26.8)	(26.8)
Other comprehensive income (loss)	-	-	-	-	-	-	-	66.4	-	-	-	66.4
Net income	-	-	-	319.0	-	148.7	-	-	-	-	37.4	505.1
Distributions	-	-	-	(353.0)	-	(140.8)	-	-	-	-	-	(493.8)
Balance December 31, 2014	-	$ -	118,586	$2,384.1	2,420	$ 78.6	$ (1.0)	$ 60.3	67	$ $(4.8)	$ 171.2	$2,688.4

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF CHANGES IN OWNERS' EQUITY

	Limited Partner		Limited Partner		General Partner		Receivables From Unit Issuances	Accumulated Other Comprehensive Income (Loss)	Treasury Units		Non-controlling Interests	Total
	Preferred	Amount	Common	Amount	Units	Amount			Units	Amount		
	(In millions, except units in thousands)											
Balance December 31, 2014	-	$ -	118,586	$2,384.1	2,420	$ 78.6	$ (1.0)	$ 60.3	67	$ $(4.8)	$ 171.2	$2,688.4
Compensation on equity grants	-	-	-	16.6	-	-	-	-	-	-	-	16.6
Distribution equivalent rights	-	-	-	(1.6)	-	-	-	-	-	-	-	(1.6)
Issuance of common units under compensation program	-	-	439	-	-	-	-	-	-	-	-	-
Units tendered for tax withholding obligations	-	-	(145)	-	-	-	-	-	145	(5.5)	-	(5.5)
Equity offerings	5,000	120.6	7,377	315.4	-	-	-	-	-	-	-	436.0
Acquisition of APL	-	-	58,614	2,583.0	-	-	-	-	-	-	216.8	2,799.8
Contributions from Targa Resources Corp.	-	-	-	-	1,353	59.1	1.0	-	-	-	-	60.1
Distributions to noncontrolling interests	-	-	-	-	-	-	-	-	-	-	(14.4)	(14.4)
Contributions from noncontrolling interests	-	-	-	-	-	-	-	-	-	-	78.4	78.4
Other comprehensive income (loss)	-	-	-	-	-	-	-	26.5	-	-	-	26.5
Net income (loss)	-	2.4	-	(197.5)	-	167.7	-	-	-	-	(31.9)	(59.3)
Distributions	-	(1.5)	-	(549.6)	-	(182.5)	-	-	-	-	-	(733.6)
Distributions payable to preferred unit holders	-	(0.9)	-	-	-	-	-	-	-	-	-	(0.9)
Targa contribution - Special General Partner Interest	-	-	-	-	-	1,612.4	-	-	-	-	-	1,612.4
Balance December 31, 2015	5,000	$ 120.6	184,871	$4,550.4	3,773	$1,735.3	$ -	$ 86.8	212	$ (10.3)	$ 420.1	$6,902.9

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2015	2014	2013
		(In millions)	
Cash flows from operating activities			
Net income (loss)	$ (59.3)	$ 505.1	$ 258.6
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Amortization in interest expense	12.6	11.2	15.5
Compensation on equity grants	16.6	9.2	6.0
Depreciation and amortization expense	677.1	346.5	271.6
Provisional goodwill impairment	290.0	-	-
Accretion of asset retirement obligations	5.3	4.4	3.9
Change in redemption value of other long term liabilities	(30.6)	-	-
Deferred income tax expense (benefit)	(0.2)	1.6	0.9
Equity (earnings) loss of unconsolidated affiliates	2.5	(18.0)	(14.8)
Distributions received from unconsolidated affiliates	13.8	18.0	12.0
Risk management activities	71.1	4.7	(0.5)
Gain) loss on sale or disposition of assets	(8.0)	(4.8)	3.9
(Gain) loss from financing activities	(2.8)	12.4	14.7
Changes in operating assets and liabilities, net of business acquisitions:			
Receivables and other assets	236.1	94.5	(145.8)
Inventory	41.4	(35.9)	(84.5)
Accounts payable and other liabilities	(181.7)	(110.4)	69.9
Net cash provided by operating activities	1,083.9	838.5	411.4
Cash flows from investing activities			
Outlays for property, plant and equipment	(817.2)	(762.2)	(1,013.6)
Business acquisition, net of cash acquired	(828.7)	-	-
Investment in unconsolidated affiliates	(11.7)	-	-
Return of capital from unconsolidated affiliates	1.2	5.7	-
Other, net	2.5	5.1	(12.7)
Net cash used in investing activities	(1,653.9)	(751.4)	(1,026.3)
Cash flows from financing activities			
Proceeds from borrowings under credit facility	1,996.0	1,600.0	1,613.0
Repayments of credit facility	(1,716.0)	(1,995.0)	(1,838.0)
Borrowings from accounts receivable securitization facility	391.6	381.9	373.3
Repayments of accounts receivable securitization facility	(355.1)	(478.8)	(93.6)
Proceeds from issuance of senior notes	1,700.0	800.0	625.0
Redemption of senior notes	(14.3)	(259.8)	(183.2)
Redemption of APL senior notes	(1,168.8)	-	-
Costs incurred in connection with financing arrangements	(26.1)	(14.0)	(15.3)
Proceeds from sale of common and preferred units	443.6	412.7	524.7
Repurchase of common units under compensation plans	(5.5)	(4.8)	-
Contributions received from General Partner	60.1	7.7	10.8
Contributions received from noncontrolling interests	78.4	-	4.3
Distributions paid to unitholders	(733.6)	(493.8)	(397.3)
Payments of distribution equivalent rights	(2.8)	(1.6)	-
Distributions paid to noncontrolling interests	(14.4)	(26.8)	(19.3)
Net cash provided by (used in) financing activities	633.1	(72.3)	604.4
Net change in cash and cash equivalents	63.1	14.8	(10.5)
Cash and cash equivalents, beginning of period	72.3	57.5	68.0
Cash and cash equivalents, end of period	$ 135.4	$ 72.3	$ 57.5

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

Note 1 — Organization and Operations

Our Organization

Targa Resources Partners LP is a publicly traded Delaware limited partnership formed in October 2006 by Targa. Our common units, which represent limited partner interests in us, are listed on the New York Stock Exchange ("NYSE") under the symbol "NGLS." In this Annual Report, unless the context requires otherwise, references to "we," "us," "our" or the "Partnership" are intended to mean the business and operations of Targa Resources Partners LP and its consolidated subsidiaries.

Targa Resources GP LLC is a Delaware limited liability company formed by Targa in October 2006 to own a 2% general partner interest in us. Its primary business purpose is to manage our affairs and operations. Targa Resources GP LLC is an indirect wholly owned subsidiary of Targa. As of December 31, 2015, Targa owned a 10.6% interest in us in the form of 3,772,871 general partner units and 16,309,594 common units. In addition, Targa Resources GP LLC also owns our incentive distribution rights ("IDRs"), which entitle it to receive increasing cash distributions up to 48% of distributable cash for a quarter, exclusive of amounts reallocated to common unit-holders under the IDR Giveback Amendment (see Note 11-Partnership Units and Related Matters).

In connection with the Atlas mergers (see Note 4 – Business Acquisitions), our Partnership Agreement was amended to provide for the issuance of a special general partner interest ("the Special GP Interest") representing a capital account credit equal to the consideration paid by Targa for and resulting tax basis in the Atlas Pipeline Partners GP, LLC, a Delaware limited liability company and the general partner of APL ("APL GP") acquired in the ATLS merger (see Note 4 – Business Acquisitions). 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 receive distributions in liquidation.

In connection with our issuance of 5,000,000 9.0% Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Preferred Units") in October 2015, our Partnership Agreement was amended and restated for the purpose of defining the preferences, rights, powers and duties of holders of our Preferred Units (see Note 11 – Partnership Units and Related Matters). Our preferred units are listed on the NYSE under the symbol "NGLS PRA."

TRC/TRP Merger

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

At the effective time of the TRC/TRP Merger, each outstanding TRP common unit not owned by TRC or its subsidiaries was converted into the right to receive 0.62 shares of common stock of TRC, par value $0.001 per share ("TRC shares"). No fractional TRC shares were issued in the TRC/TRP Merger, and TRP common unitholders instead received cash in lieu of fractional TRC shares.

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; gathering, storing and terminaling crude oil; and storing, terminaling and selling refined petroleum products. See Note 23-Segment Information for certain financial information for our business segments.

The employees supporting our operations are employed by Targa. Our financial statements include the direct costs of Targa employees deployed to our operating segments, as well as an allocation of costs associated with our usage of Targa's centralized general and administrative services.

Note 2 — Basis of Presentation

These accompanying financial statements and related notes present our consolidated financial position as of December 31, 2015 and 2014, and the results of operations, comprehensive income, cash flows and changes in owners' equity for the years ended December 31, 2015, 2014, and 2013.

We have prepared our consolidated financial statements in accordance with accounting principles generally accepted in the United States of America ("GAAP"). All significant intercompany balances and transactions have been eliminated. Certain amounts in prior periods have been reclassified to conform to the current year presentation.

The February 27, 2015 Atlas mergers involved two separate legal transactions involving different groups of equity holders. For GAAP reporting purposes, these two mergers are viewed as a single integrated transaction. As such, the financial effects of the Targa consideration related to the ATLS merger have been reflected in these financial statements. As described in Note 4 – Business Acquisitions, our Partnership Agreement was amended to provide for the issuance of the Special GP Interest in us equal to the tax basis of the APL GP Interests acquired in the ATLS merger totaling $1.6 billion. 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.

Impact of Errors

On February 27, 2015, Targa completed the Atlas mergers (see Note 4 – Business Acquisitions). During the fourth quarter of 2015, we concluded that our review procedures over the development and application of inputs, assumptions, and calculations used in cash flow-based fair value measurements associated with business combinations did not operate as designed. This resulted in errors in the preliminary fair values of our purchase accounting previously reported in our interim quarterly filings during 2015. The correction of these items in the fourth quarter of 2015 resulted in an increase to intangible assets, goodwill and noncontrolling interests, and a decrease to property, plant and equipment in each period.

We concluded that these errors were not material to any of the periods affected. The following table presents for each period the impact of these errors on previously reported balances, as well as the effect of ordinary measurement period adjustments.

	Three Month Period			
	As Reported	Impact of Errors	Other Measurement Period Adjustments (1)	As If Adjusted
March 31, 2015				
Property, plant and equipment, net	$ 9,832.9	$ (77.0)	$ (248.8)	$ 9,507.1
Intangible assets, net	1,602.4	114.5	204.1	1,921.0
Goodwill	628.5	48.5	30.0	707.0
Noncontrolling interests	480.7	86.2	(173.2)	393.7
Depreciation and amortization expenses	119.6	0.2	(0.2)	119.6
June 30, 2015				
Property, plant, and equipment, net	$ 9,684.3	$ (76.0)	$ 1.0	$ 9,609.3
Intangible assets, net	1,735.6	113.1	35.4	1,884.1
Goodwill	557.9	48.5	100.6	707.0
Noncontrolling interests	297.4	86.2	17.2	400.8
Depreciation and amortization expenses	163.9	0.5	0.5	164.9
September 30, 2015				
Property, plant, and equipment, net	$ 9,750.2	$ (75.0)	$ (8.6)	$ 9,666.6
Intangible assets, net	1,695.7	111.6	39.8	1,847.1
Goodwill	551.4	48.5	107.1	707.0
Noncontrolling interests	309.6	86.2	17.3	413.1
Depreciation and amortization expenses	165.8	0.5	0.4	166.7

(1) Other Measurement Period Adjustments for Goodwill include the impact of all balance sheet adjustments not presented in this table.

Revision of Previously Reported Revenues and Product Purchases

During the third quarter of 2014, we concluded that certain prior period buy-sell transactions related to the marketing of NGL products were incorrectly reported on a gross basis as Revenues and Product Purchases in previous Consolidated Statements of Operations. GAAP requires that such transactions that involve purchases and sales of inventory with the same counterparty that are legally contingent or in contemplation of one another be reported as a single transaction on a combined net basis.

We concluded that these misclassifications were not material to any of the periods affected. However, we have revised previously reported revenues and product purchases to correctly report NGL buy-sell transactions on a net basis. Accordingly, Revenues and Product Purchases reported in our Form 10-K filed on February 14, 2014 have been reduced by equal amounts as presented in the following table. There is no impact on previously reported net income, cash flows, financial position or other profitability measures.

	Year Ended December 31, 2013
As Reported:	
Revenues	$ 6,556.2
Product Purchases	5,378.5
Effect of Revisions:	
Revenues	(241.3)
Product Purchases	(241.3)
As Revised:	
Revenues	6,314.9
Product Purchases	5,137.2

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 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 can 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.

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 for a check generally occurs when our bank honors that check).

Comprehensive Income (Loss)

Comprehensive income (loss) includes net income (loss) and other comprehensive income ("OCI"), which includes changes in the fair value of derivative instruments that are designated as 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 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 market 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 employ derivative instruments to manage the volatility of cash flows due to fluctuating energy prices and interest rates. 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 and from interest rate derivative instruments in interest expense.

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 our 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 contracts on a deal by deal basis and report the related fair value on a gross basis.

Property, Plant and Equipment

Property, plant and equipment are stated at acquisition value less accumulated depreciation. All of our property, plant and equipment purchased from Targa from 2007 to 2010 in drop-down transactions were stated at historical cost in the transactions recorded under common control accounting. 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.

Our 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 with the asset's expected future 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 increased depreciation expense 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 depreciation expense due to impairment. 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 assigned 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). Goodwill resulting from the Atlas merger has been attributed to our WestTX, SouthOK and SouthTX reporting units.

Our annual goodwill impairment testing is performed as of November 30, as well as whenever events or changes in circumstances indicate it is more likely than not the fair value of these reporting units is less than their carrying amounts. This typically entails performing a two-step goodwill impairment test. However, we are permitted to first assess qualitative factors to determine the two-step goodwill impairment test is necessary. If we choose to bypass this qualitative assessment or otherwise determine if that a two-step process goodwill impairment test is required, the first step involves comparing the fair value of the reporting unit to which goodwill has been attributed with its carrying amount. If the carrying amount of a reporting unit exceeds its fair value, the second step is required and involves comparing the implied fair value to the carrying value of the goodwill for that reporting unit. The implied fair value of goodwill is determined by assigning the reporting unit's fair value to its individual assets and liabilities. If the carrying value of the goodwill of a reporting unit exceeds the implied fair value of that goodwill, the excess of the carrying value over the implied fair value is recognized as a reduction of goodwill on our Consolidated Balance Sheets and a goodwill impairment loss on our Consolidated Statements of Operations.

Intangible Assets

Intangible assets arose from producer dedications under long-term contracts and customer relationships associated with businesses 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 pattern in which we benefit from services provided to customers.

***Asset Retirement Obligations* (“*AROs*”)**

AROs are legal obligations associated with the retirement of tangible long-lived assets that result from an asset's acquisition, construction, development and/or normal operation. An ARO is initially measured at its estimated fair value. Upon initial recognition of an ARO, we record an increase to the carrying amount of the related long-lived asset and an offsetting ARO liability. The consolidated cost of the asset and the capitalized asset retirement obligation is depreciated using the straight-line method over the period during which the long-lived asset is expected to provide benefits. After the initial period of ARO recognition, the ARO will change as a result of either the passage of time or revisions to the original estimates of either the amounts of estimated cash flows or their timing.

Changes due to the passage of time increase the carrying amount of the liability because there are fewer periods remaining from the initial measurement date until the settlement date; therefore, the present values of the discounted future settlement amount increases. These changes are recorded as a period cost called accretion expense. Changes resulting from revisions to the timing or the amount of the original estimate of undiscounted cash flows shall be recognized as an increase or a decrease in the carrying amount of the liability for an asset retirement obligation and the related asset retirement cost capitalized as part of the carrying amount of the related long-lived asset. Upon settlement, AROs will be extinguished by us at either the recorded amount or we will recognize a gain or loss on the difference between the recorded amount and the actual settlement cost.

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. 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 our Accounts Receivable Securitization Facility (the “Securitization Facility”) are treated as collateralized borrowings in our financial statements. Such borrowings are reflected as long-term debt on our balance sheets to the extent that we have the ability and intent to fund the Securitization Facility's borrowings on a long-term basis. Proceeds and repayments under the Securitization Facility are reflected as cash flows from financing activities on 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 expense when it is probable that a liability has been incurred and the amount of the loss can be reasonably estimated.

Income Taxes

We generally are not subject to federal income taxes. For federal income tax purposes, our earnings or losses are included in the tax returns of our separate partners. The taxable income or loss passed through to our partners may vary substantially from the net income or net loss we report in the Consolidated Statement of Income.

As part of the APL Merger, we acquired TPL Arkoma, Inc. a corporate subsidiary subject to federal and state income tax. The Partnership's corporate subsidiary accounts for income taxes under the asset and liability method and provides deferred income taxes for all significant temporary differences.

As part of the process of preparing our consolidated financial statements, we are required to estimate our income taxes for our taxable corporate subsidiary. This process involves estimating our actual current tax payable and related tax expense together with assessing temporary differences resulting from differing treatment of certain items, such as depreciation, for tax and accounting purposes. These differences can result in deferred tax assets and liabilities, which are included within our Consolidated Balance Sheets.

We must then assess the likelihood that our deferred tax assets will be recovered from future taxable income and, to the extent 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, both positive and negative, to determine whether, based on the weight of the evidence, a valuation allowance is needed. Evidence used includes information about our current financial position and our results of operations for the current and preceding years, as well as all currently available information about future years, including our anticipated future performance, the reversal of deferred tax liabilities and tax planning strategies.

The effective tax rate differs from the statutory rate due primarily to Partnership earnings that are generally not subject to federal and state income taxes at the Partnership level. We are also subject to the Texas margin tax, consisting generally of a 0.75% tax on the amount by which total revenues exceed cost of goods sold, as apportioned to Texas. See Note 18 for discussion of the Partnership's federal and state income tax expense (benefits) of its taxable subsidiary as well as the Partnership's net deferred income tax assets (liabilities).

Noncontrolling Interests

Third-party ownership in the net assets of our consolidated subsidiaries is shown as noncontrolling interests within the equity section of our Consolidated Balance Sheets. In the 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 occur in the future when the interests are redeemed. Changes in the redemption value are recorded in interest expense, net on 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 or a percentage of commodities 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 that 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. 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 receive for services or purchase for resale 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.

Unit-Based Compensation

We award unit-based compensation to employees of Targa and to directors and non-management directors of our General Partner in the form of restricted common units and performance units. Compensation expense on restricted common units and performance 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 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.

Earnings per Unit

We account for earnings per unit (“EPU”) in accordance with Accounting Standards Codification (“ASC”) Topic 260 – Earnings per Share. Diluted EPU reflects the potential dilution that could occur if securities or other contracts to issue common units were exercised or converted into common units or resulted in the issuance of common units so long as it does not have an anti-dilutive effect on EPU. The dilutive effect is determined through the application of the treasury method. Securities that meet the definition of a participating security are required to be considered for inclusion in the computation of basic EPU.

The common limited partners’ net income (loss) per unit is based on net income (loss) after net income attributable to Preferred Units, allocation to the general partner’s 2% interest and incentive distribution rights. Because our Partnership Agreement limits the quarterly distribution payable to holders of incentive distribution rights to a percentage of Available Cash, the incentive distribution rights do not receive an allocation of earnings in excess of the incentive distributions for the period.

Use of Estimates

When preparing financial statements in conformity with GAAP, management must make estimates and assumptions based on information available at the time. These estimates and assumptions affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosures of contingent assets and liabilities as of the date of the financial statements. 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 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.

Recent Accounting Pronouncements

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 identifying the contracts with customers, identifying the performance obligations in the contracts, determining the transaction price, allocating the transaction price to the performance obligations, and 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.

The revenue recognition standard is effective for the annual period beginning December 15, 2017, and for annual and interim periods thereafter. Earlier adoption is permitted only as of annual reporting periods beginning after December 15, 2016, including interim reporting periods within that reporting period. We must retroactively 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 amendment is adopted. We expect to adopt this guidance on January 1, 2018 and are continuing to evaluate the impact on our revenue recognition practices.

In November 2014, the FASB issued ASU 2014-16, *Derivatives and Hedging (Topic 815): Determining Whether the Host Contract in a Hybrid Financial Instrument Issued in the Form of a Share Is More Akin to Debt or to Equity (a consensus of the FASB Emerging Issues Task Force).* The amendments in this update clarify how current GAAP should be interpreted in evaluating the economic characteristics and risks of a host contract in a hybrid financial instrument that is issued in the form of a share. These amendments have been adopted, with no material impact on our consolidated financial statements or results of operations.

In February 2015, the FASB issued ASU 2015-02, *Consolidation (Topic 810): Amendments to the Consolidation Analysis*. The amendments in this update are intended to simplify the consolidation evaluation for reporting organizations that are required to evaluate whether they should consolidate certain legal entities and modify the evaluation of whether limited partnerships and similar legal entities are variable interest entities or voting interest entities. We are currently evaluating the effect of the amendments by revisiting our consolidation model for each of our less-than-wholly owned subsidiaries. The amendments are effective for us in the first quarter of 2016 and are not expected to have a material impact on our consolidated financial statements or related disclosures.

In April 2015, the FASB issued ASU 2015-03, *Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs*. The amendments in this update require that debt issuance costs related to a recognized debt liability (other than revolving credit facilities) be presented in the Consolidated Balance Sheets as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. This update deals solely with financial statement display matters; recognition and measurement of debt issuance costs are unaffected. Unamortized debt issuance costs of $38.3 million and $29.9 million for term loans and notes were included in Other long-term assets on the Consolidated Balance Sheets as of December 31, 2015 and December 31, 2014. In August 2015, the FASB issued ASU 2015-15, *Interest - Imputation of Interest (Subtopic 835-30): Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements*. The amendment clarifies ASU 2015-03 and provides that an entity may defer and present debt issuance costs for a line-of-credit or other revolving credit facility arrangement as an asset and subsequently amortize the deferred debt issuance costs ratably over the term of the arrangement, regardless of whether there are any outstanding borrowings on the arrangement. Unamortized debt issuance costs of $5.9 million and $7.4 million for revolving credit facilities were included in Other long-term assets on the Consolidated Balance Sheets as of December 31, 2015 and December 31, 2014. We will continue to include debt issuance costs for our line-of-credit and revolving credit facility arrangements in Other long-term assets upon adoption of ASU 2015-03. These amendments are effective for us on January 1, 2016.

In July 2015, the FASB issued ASU 2015-11, *Inventory (Topic 303): Simplifying the Measurement of Inventory. Topic 303* currently requires inventory to be measured at the lower of cost or market, where market could be replacement cost, net realizable value or net realizable value less a normal profit margin. The amendments in this update require that all inventory, excluding inventory that is measured using the last-in, first-out method or the retail inventory method, be measured at the lower of cost or net realizable value. Net realizable value is defined as the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. These amendments have been adopted, with no impact on our consolidated financial statements or results of operations.

In September 2015, the FASB issued ASU 2015-16, *Business Combinations (Topic 805): Simplifying the Accounting for Measurement-Period Adjustments.* Topic 805 currently requires that adjustments to provisional amounts recorded in a business combination be recognized retrospectively as if the accounting had been completed at the acquisition date. The amendments in this update require that an acquirer recognize these measurement-period adjustments in the reporting period in which the adjustment amounts are determined, with the effect on earnings of changes in depreciation, amortization or other income effects, if any, as a result of the change to the provisional amounts, calculated as if the accounting had been completed at the acquisition date. The amendments require disclosure of the amount recorded in current-period earnings that would have been recorded in previous reporting periods if the adjustment to the provisional amounts had been recognized as of the acquisition date. The amendments are effective for us in 2016, with early adoption permitted. We adopted the amendments on September 30, 2015 and have recognized the measurement-period adjustments for the Atlas mergers determined in the six months ended December 31, 2015 in current period earnings. See Note 4 –Business Acquisitions for additional information regarding the nature and amount of the measurement-period adjustments.

In November 2015, the FASB issued ASU 2015-17, *Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes*. The amendments in this update require that deferred tax asset and liabilities be classified as noncurrent on the consolidated balance sheet. These amendments have been adopted, with no impact on our consolidated financial statements or results of operations.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)*. The amendments in this update require, among other things, that lessees recognize the following for all leases (with the exception of short-term leases) at the commencement date: (1) a lease liability, which is a lessee's obligation to make lease payments arising from a lease, measured on a discounted basis; and (2) a right-of-use asset, which is an asset that represents the lessee's right to use, or control the use of, a specified asset for the lease term. Lessees and lessors must apply a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. We expect to adopt the amendments in the first quarter of 2019 and are currently evaluating the impacts of the amendments to our financial statements and accounting practices for leases.

Note 4 –Business Acquisitions

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"), 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, 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."

While the Atlas mergers were two separate legal transactions, for GAAP reporting purposes, they are viewed as a single integrated transaction. As such, the financial effects of the ATLS Merger Consideration (as defined below) paid by Targa have been reflected in these financial statements.

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 Agreement was amended to provide for the issuance of a special general partner interest in the Partnership (the "Special GP Interest") representing the contribution to the Partnership of the APL GP interest acquired in the ATLS merger totaling $1.6 billion. 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.

We 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 our 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, Targa acquired ATLS for a total purchase price of approximately $1.6 billion (including all assumed liabilities).

Pursuant to the APL Merger Agreement, our general partner entered into an amendment to our Partnership Agreement, which we refer to as the IDR Giveback Amendment, in order to reduce aggregate distributions to TRC, 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 our outstanding common units.

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 play in south Texas. The Atlas mergers add TPL's Woodford/SCOOP, Mississippi Lime, Eagle Ford and additional Permian assets to the Partnership's existing operations. In total, TPL adds 2,053 MMcf/d of processing capacity and 12,220 miles of additional pipeline. The operating results of TPL are reported in our Field Gathering and Processing segment.

The APL merger was a unit-for-unit transaction with an exchange ratio of 0.5846 of our 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. We issued 58,614,157 of our 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, Targa contributed $52.4 million to us to maintain its 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). Targa issued 10,126,532 of its 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. Targa’s acquisition of ATLS resulted in Targa acquiring these common units (converted to 3,363,935 of our common units) valued at approximately $147.4 million (based on the $43.82 closing market price of our common units 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 Targa 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 our 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 us for the period from February 27, 2015 to December 31, 2015, and is reported in our Field Gathering and Processing segment. In 2015, we incurred $19.2 million of acquisition-related costs. These expenses are included in other expense in our Consolidated Statements of Operations for the year ended December 31, 2015.

Pro Forma Impact of Atlas Mergers on Consolidated Statements of Operations

The following summarized unaudited pro forma Consolidated Statement of Operations information for the year ended December 31, 2015 and December 31, 2014 assumes that our acquisition of APL and Targa's 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.

	Pro Forma Results for the Year Ended	
	December 31, 2015	December 31, 2014
Revenues	$ 6,947.3	$ 11,449.3
Net income (loss)	(62.2)	691.2

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 with 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 which 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 APL businesses sold during the periods: (1) the May 2014 sale of APL's 20% interest in West Texas LPG Pipeline Limited Partnership and (2) 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 $19.2 million of acquisition-related costs incurred in 2015 from pro forma net income for the year ended December 31, 2015. Pro forma net income for the year ended December 31, 2014 was adjusted to include these charges.
- Conform to our accounting policy, we also adjusted APL's revenues to report plant sales of Y-grade at contractual net values rather than grossed up for transportation and fractionation deduction factors.

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 by Targa for ATLS:	
Cash paid, net of cash acquired (1)	$ 745.7
Common shares of TRC	1,008.5
Replacement restricted stock units awarded (3)	5.2
Less: value of APL common units owned by ATLS	(147.4)
Total	$ 1,612.0
Fair Value of Consideration Transferred by Targa for APL:	
Cash paid, net of cash acquired (2)	$ 828.7
Common units of TRP	2,568.5
Replacement phantom units awarded (3)	15.0
Total	$ 3,412.2
Total fair value of consideration transferred	$ 5,024.2

(1) Targa acquired $5.5 million of cash.
(2) We acquired $35.3 million of cash.
(3) 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.

As of February 27, 2015, our 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	(258.8)
Long-term debt	(1,573.3)
Deferred income tax liabilities, net	(13.6)
Other long-term liabilities	(119.1)
Total identifiable net assets	4,534.6
Noncontrolling interest in subsidiaries	(216.9)
Current liabilities retained by Targa	(0.5)
Goodwill	707.0
	$ 5,024.2

During the three months ended June 30, 2015, we recorded measurement-period adjustments to our acquisition date fair values due to the refinement of our valuation models, assumptions and inputs. As a result, the Consolidated Statement of Operations for the three months ended March 31, 2015 was retrospectively adjusted for the impact of measurement-period adjustments to property, plant and equipment, intangible assets, and investment in unconsolidated affiliates. These adjustments resulted in a decrease in depreciation and amortization expense of $1.0 million, and an increase in equity earnings of $0.3 million from the amounts previously reported in our Form 10-Q for the quarter ended March 31, 2015.

During the three months ended September 30, 2015, we recorded additional measurement-period adjustments to our acquisition date fair values due to the refinement of our valuation models, assumptions and inputs. In accordance with ASU 2015-16, we have recognized these measurement-period adjustments in the current reporting period, with the effect on the Consolidated Statements of Operations resulting from the change to the provisional amounts calculated as if the acquisition had been completed at February 27, 2015. During the three months ended September 30, 2015, the acquisition date fair value of property, plant and equipment increased by $9.9 million, investments in unconsolidated affiliates increased by $5.5 million, intangible assets decreased by $5.0 million, current liabilities increased by $2.4 million, other assets decreased by $1.0 million, and other current assets decreased by $0.6 million, which resulted in a decrease in goodwill of $6.4 million. These adjustments resulted in increased revenues of $0.6 million, a reduction of operating expenses of $1.9 million, depreciation and amortization expense of $0.1 million and equity losses of $0.1 million recorded in the three months ended September 30, 2015, which under the prior accounting standard would have been reflected in previous reporting periods.

During the three months ended December 31, 2015, we recorded additional measurement-period adjustments to our acquisition date fair values due to the refinement of our valuation models, assumptions and inputs, as well as adjustments to previously reported preliminary fair values as a result of our review procedures over the development and application of inputs, assumptions and calculations used in cash-flow based fair value measurements associated with business combinations not operating as designed (see Note 2 – Basis of Presentation). We have recognized these adjustments in the current reporting period, with the effect on the Consolidated Statements of Operations resulting from the change to the provisional amounts calculated as if the acquisition had been completed at February 27, 2015. During the three months ended December 31, 2015, the acquisition date fair value of intangible assets increased $155.9 million, noncontrolling interest in subsidiaries increased $103.5 million, other long-term liabilities increased $110.1 million, property, plant and equipment decreased by $86.2 million, investments in unconsolidated affiliates decreased by $5.2 million, deferred tax liabilities increased by $5.0 million, current liabilities increased by $1.3 million, other assets decreased by $0.1 million and other current assets decreased by $0.1 million, which resulted in an increase in goodwill of $155.6 million. These adjustments resulted in depreciation and amortization expenses of $2.0 million, a net decrease to interest expense of $26.2 million, equity earnings of $0.2 million, and a reduction of general and administrative expenses of $0.4 million, recorded in the three months ended December 31, 2015, which under the prior accounting standard would have been reflected in previous reporting periods.

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

The excess of the purchase price 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 with us and Targa. The goodwill is expected to be amortizable for tax purposes.

The fair value of assets acquired includes trade receivables of $178.1 million. The gross amount due under contracts is $178.1 million, all of which is expected to be collectible. The fair value of assets acquired includes 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.

See Note 9 – Debt Obligations for additional disclosures regarding related financing activities associated with the Atlas mergers.

Mandatorily Redeemable Preferred Interests

Acquired other long-term liabilities include $109.3 million related to mandatorily redeemable preferred interests held by our partner in two joint ventures (see note 10 – 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 fair value of the remaining contingent payment is recorded within other long term liabilities on our Consolidated Balance Sheets. The range of the undiscounted amount that we could pay related to the remaining contingent payment is between $0.0 and $6.0 million. We finalized our acquisition analysis and modeling of this contingent liability during the three months ended June 30, 2015, which resulted in an acquisition date fair value of $4.2 million. Any future change in the fair value of this liability will be included in earnings.

Replacement Phantom Units

In connection with the Atlas mergers, we 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 will 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 one common unit on the vesting date and is an equity-settled award. The replacement phantom units include distribution equivalent rights ("DERs"). When we declare and pay cash distributions, the holders of replacement phantom units will be entitled within 60 days to receive cash payment of DERs 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 our common units related to the replacement phantom units.

The fair value of the replacement phantom units was based on the closing price of our 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.

Goodwill

We recognized goodwill at a fair value of approximately $707.0 million associated with the Atlas mergers as of the acquisition date on February 27, 2015. Goodwill has been attributed to the WestTX, SouthTX and SouthOK reporting units in our Field Gathering and Processing segment. As a result, any level of decrease in the forecasted cash flows from the date of acquisition would likely result in the fair value of the reporting unit to fall below the carrying value of the reporting unit, and could result in an assessment of whether that reporting unit's goodwill could be impaired.

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. As of February 29, 2016, the date these financial statements were issued, we had not completed our November 30, 2015 impairment assessment. Based on the results of our preliminary evaluation, we recorded a provisional goodwill impairment of $290.0 million during the fourth quarter of 2015. The provisional goodwill impairment is included in impairment expense in our Consolidated Statements of Operations for the year ended December 31, 2015, and reduces the carrying value of goodwill to $417.0 million as of December 31, 2015. The provisional goodwill impairment recorded reflects that goodwill impairment is probable; a provisional impairment amount can be reasonably estimated and recognizes the provisional amount in these financial statements as the best estimate of the impairment at the filing date of these financial statements. The impairment of goodwill is 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.

Our evaluation as of November 30, 2015 utilizes the income approach (a discounted cash flow analysis ("DCF")) to estimate the fair values of our reporting units. The future cash flows for our reporting units is based on our estimates, at that time, of future revenues, income from operations and other factors, such as working capital and capital expenditures. We take into account current and expected industry and market conditions, 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 provisional goodwill impairment recognized is based on our progress in completing the goodwill impairment analysis. As of the filing date of these financial statements, we have (a) completed the calculations of estimated future cash flows based on commodity pricing, volumetric and capital spending forecasts; (b) determined that other long-lived assets in our reporting units that contain goodwill are not impaired; (c) determined an appropriate weighted average cost of capital based on relevant market comparisons, which is the basis of the discount rate used in our DCF analysis; (d) substantially completed the valuations of intangible assets; and (e) have made initial estimates of the fair values of tangible assets. We are in the process of finalizing the review of certain tangible assets and the mandatorily redeemable preferred interests' valuations, and the final outcome of these valuations could impact the implied fair value of goodwill in our reporting units and consequently the ultimate amount of impairment. Any material difference between the provisional amount of goodwill impairment and the final impairment will be recognized in our first quarter 2016 financial statements once final valuations are complete.

Changes in the gross amounts of our goodwill and impairment loss for the year ended December 31, 2015 are as follows:

	December 31, 2015			
	WestTX	SouthTX	SouthOK	Total
Beginning of period	$ -	$ -	$ -	$ -
Acquisition	364.5	160.3	182.2	707.0
Impairment	(37.6)	(70.2)	(182.2)	(290.0)
Goodwill	$ 326.9	$ 90.1	$ -	$ 417.0

The sustained decrease and uncertain outlook in commodity prices have adversely impacted our customers and their future capital and operating plans. A continued or prolonged period of lower commodity prices could result in further deterioration of reporting unit fair values and potential further impairment charges.

Note 5 — Inventories

	December 31, 2015	December 31, 2014
Commodities	$ 128.3	$ 157.4
Materials and supplies	12.7	11.5
	$ 141.0	$ 168.9

Note 6 — Property, Plant and Equipment and Intangible Assets

Property, Plant and Equipment

	December 31, 2015	December 31, 2014	Estimated useful life (In Years)
Gathering systems	$ 6,304.5	$ 2,588.6	5 to 20
Processing and fractionation facilities	2,988.5	1,884.1	5 to 25
Terminaling and storage facilities	1,115.0	1,038.9	5 to 25
Transportation assets	454.0	359.0	10 to 25
Other property, plant and equipment	220.9	149.1	3 to 25
Land	108.8	95.6	-
Construction in progress	736.5	399.0	-
Property, plant and equipment	11,928.2	6,514.3	
Accumulated depreciation	(2,225.6)	(1,689.7)	
Property, plant and equipment, net	$ 9,702.6	$ 4,824.6	
Intangible assets	$ 2,036.6	$ 681.8	20
Accumulated amortization	(226.5)	(89.9)	
Intangible assets, net	$ 1,810.1	$ 591.9	

For each of the years ended December 31, 2015, 2014, and 2013 depreciation expense for property, plant and equipment was $540.5 million, $285.0 million and $244.2 million.

We recorded non-cash pre-tax impairment charges of $32.6 million in 2015 and $3.2 million in 2014 due to the impairment of certain gas processing facilities and associated gathering systems in the Coastal Gathering and Processing segment. The impairments are a result of reduced forecasted gas processing volumes due to market conditions and processing spreads in Louisiana in the fourth quarters of 2015 and 2014. 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 depreciation and amortization expenses on our Consolidated Statements of Operations.

Intangible Assets

Intangible assets consist of customer contracts and customer relationships acquired in the Atlas mergers in 2015 and our Badlands business acquisition in 2012. The fair values of these acquired intangible assets were determined at the date of acquisition based on the present values of estimated future cash flows. Key valuation assumptions include probability of contracts under negotiation, renewals of existing contracts, economic incentives to retain customers, past and future volumes, current and future capacity of the gathering system, pricing volatility and the discount rate.

The fair values of intangible assets acquired in the Atlas mergers have been recorded at a fair value of $1,354.9 million and are being amortized over the 20 year life using a straight-line method. Amortization expense attributable to our intangible assets related to the Badlands acquisition is recorded using a method that closely reflects the cash flow pattern underlying their intangible asset valuation.

	December 31,	
	2015	2014
Beginning of period	$ 591.9	$ 653.4
Additions from acquisition	1,354.9	-
Amortization	(136.7)	(61.5)
Intangible assets, net	$ 1,810.1	$ 591.9

For each of the years ended December 31, 2015, 2014, and 2013 amortization expense for our intangible assets was $136.7 million, $61.5 million and $27.4 million. The estimated annual amortization expense for intangible assets is approximately $156.2 million, $149.4 million, $135.7 million, $124.7 million and $112.5 million for each of the years 2016 through 2020. As of December 31, 2015 the weighted average amortization period for our intangible assets was approximately 18.5 years.

Note 7 — Investments in Unconsolidated Affiliates

Our unconsolidated investments consist of a 38.8% non-operated ownership interest in Gulf Coast Fractionators LP (“GCF”) and three non-operated joint ventures in South Texas acquired in the Atlas merger in 2015: 75% interest in T2 LaSalle; 50% interest in T2 Eagle Ford; and 50% interest in T2 EF Co-Gen (together the “T2 Joint Ventures”). The T2 Joint Ventures were formed to provide services for the benefit of the joint interest owners. The T2 Joint Ventures have capacity lease agreements with the joint interest owners, which cover the costs of operations of the T2 Joint Ventures. The terms of these joint venture agreements do not afford us the degree of control required for consolidating them in our consolidated financial statements, but do afford us the significant influence required to employ the equity method of accounting.

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

	GCF	T2 LaSalle	T2 Eagle Ford	T2 Cogen	Total
December 31, 2012	$ 53.1	$ -	$ -	$ -	$ 53.1
Equity earnings	14.8	-	-	-	14.8
Cash distributions (1)	(12.0)	-	-	-	(12.0)
December 31, 2013	55.9	-	-	-	55.9
Equity earnings	18.0	-	-	-	18.0
Cash distributions (1)	(23.7)	-	-	-	(23.7)
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
December 31, 2015	$ 49.5	$ 63.6	$ 123.8	$ 22.0	$ 258.9

(1) Includes $1.2 million in distributions from GCF and T2 Joint Ventures in excess of our share of cumulative earnings for the year ended December 31, 2015. Includes $5.7 million in distributions from GCF in excess of our share of cumulative earnings for the year ended December 31, 2014. Such excess distributions are considered a return of capital and disclosed in cash flows from investing activities in the Consolidated Statements of Cash Flows.

The recorded value of the T2 Joint Ventures is based on fair values at the date of acquisition which results in an excess fair value of $39.9 million over the book value of our partner capital accounts. This basis difference is attributable to depreciable tangible assets and is being amortized over the estimated useful lives of the underlying assets of 20 years on a straight-line basis and is included as a component of equity earnings. See Note 4 – Business Acquisitions for further information regarding the fair value determinations related to the Atlas mergers.

Note 8 — Accounts Payable and Accrued Liabilities

	December 31, 2015	December 31, 2014
Commodities	$ 385.3	$ 416.7
Other goods and services	141.3	108.9
Interest	80.3	37.3
Compensation and benefits	0.4	1.3
Income and other taxes	10.4	13.6
Other	18.1	14.9
	$ 635.8	$ 592.7

As of December 31, 2015 and December 31, 2014, liabilities to creditors to whom we have issued checks that remain outstanding of $34.0 million and $13.3 million are included in accounts payable and accrued liabilities.

Note 9 — Debt Obligations

	December 31, 2015	December 31, 2014
Current:		
Accounts receivable securitization facility, due December 2016	$ 219.3	$ 182.8
Long-term:		
Senior secured revolving credit facility, variable rate, due October 2017 (1)	280.0	-
Senior unsecured notes, 5% fixed rate, due January 2018	1,100.0	-
Senior unsecured notes, 4⅛% fixed rate, due November 2019	800.0	800.0
Senior unsecured notes, 6⅝% fixed rate, due October 2020 (2)	342.1	-
Unamortized premium	5.0	-
Senior unsecured notes, 6⅞% fixed rate, due February 2021	483.6	483.6
Unamortized discount	(22.1)	(25.2)
Senior unsecured notes, 6⅜% fixed rate, due August 2022	300.0	300.0
Senior unsecured notes, 5¼% fixed rate, due May 2023	583.7	600.0
Senior unsecured notes, 4¼% fixed rate, due November 2023	623.5	625.0
Senior unsecured notes, 6¾% fixed rate, due March 2024	600.0	-
Senior unsecured APL notes, 6⅝% fixed rate, due October 2020 (2)(3)	12.9	-
Unamortized premium	0.2	-
Senior unsecured APL notes, 4¾% fixed rate, due November 2021 (3)	6.5	-
Senior unsecured APL notes, 5⅞% fixed rate, due August 2023 (3)	48.1	-
Unamortized premium	0.5	-
Total long-term debt	5,164.0	2,783.4
Total debt	$ 5,383.3	$ 2,966.2
Irrevocable standby letters of credit outstanding	$ 12.9	$ 44.1

(1) As of December 31, 2015, availability under our $1.6 billion senior secured revolving credit facility was $1,307.1 million.
(2) In May 2015, we exchanged the TRP 6⅝% Senior Notes with the same economic terms to the holders of the 6⅝% APL Notes that validly tendered such notes for exchange to us.
(3) While we consolidate the debt acquired in the Atlas mergers, APL debt is not guaranteed by us.

The following table shows the contractually scheduled maturities of our debt obligations outstanding at December 31, 2015, for the next five years, and in total thereafter:

	Total	Scheduled Maturities of Debt					
		2016	2017	2018	2019	2020	After 2020
Senior secured revolving credit facility	$ 280.0	$ -	$ 280.0	$ -	$	$ -	$ -
Senior unsecured notes	4,900.4	-	-	1,100.0	800.0	355.0	2,645.4
Accounts receivable securitization facility	219.3	219.3	-	-	-	-	-
Total	$ 5,399.7	$ 219.3	$ 280.0	$ 1,100.0	$ 800.0	$ 355.0	$ 2,645.4

The following table shows the range of interest rates and weighted average interest rate incurred on our variable-rate debt obligations during the year ended December 31, 2015:

	Range of Interest Rates Incurred	Weighted Average Interest Rate Incurred
Senior secured revolving credit facility	1.9% - 4.8%	2.2%
Accounts receivable securitization facility	0.9% - 1.2%	0.9%

Compliance with Debt Covenants

As of December 31, 2015, we were in compliance with the covenants contained in our various debt agreements.

Revolving Credit Agreement

In October 2012, we entered into a Second Amended and Restated Credit Agreement that amended and replaced our variable rate Senior Secured Credit Facility due July 2015 to provide a variable rate Senior Secured Credit Facility due October 3, 2017 (the “Original Agreement”). The Original Agreement had an available commitment of $1.2 billion and allowed us to request up to an additional $300.0 million in commitment increases.

In February 2015, we entered into the First Amendment, Waiver and Incremental Commitment Agreement (the “First Amendment”) that amended the Original Agreement. The First Amendment increased available commitments to $1.6 billion from $1.2 billion while retaining our ability to request up to an additional $300.0 million in commitment increases. In addition, the First Amendment amended certain provisions of the existing TRP Revolver and designated each of TPL and its subsidiaries as an “Unrestricted Subsidiary.” We used proceeds from borrowings under the credit facility 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 our option, either at the base rate or the Eurodollar rate. The base rate is equal to the highest of: (i) Bank of America’s prime rate; (ii) the federal funds rate plus 0.5%; or (iii) the one-month LIBOR rate plus 1.0%, plus an applicable margin ranging from 0.75% to 1.75% (dependent on our 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 our ratio of consolidated funded indebtedness to consolidated adjusted EBITDA).

We are required to pay a commitment fee equal to an applicable rate ranging from 0.3% to 0.5% (dependent on our 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 our ratio of consolidated funded indebtedness to consolidated adjusted EBITDA).

The TRP Revolver is collateralized by a majority of our assets. Borrowings are guaranteed by our restricted subsidiaries.

The TRP Revolver restricts our ability to make distributions of available cash to unitholders if a default or an event of default (as defined in the TRP Revolver) exists or would result from such distribution. The TRP Revolver requires us 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 us to maintain a ratio of consolidated 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, our ability to incur indebtedness, grant liens, make investments, repay or amend the terms of certain other indebtedness, merge or consolidate, sell assets, and engage in transactions with affiliates (in each case, subject to our right to incur indebtedness or grant liens in connection with, and convey accounts receivable as part of, a permitted receivables financing).

Senior Unsecured Notes

In May 2013, we privately placed $625.0 million in aggregate principal amount of 4¼% Notes. The 4¼% Notes resulted in approximately $618.1 million of net proceeds, which were used to reduce borrowings under the TRP Revolver and for general partnership purposes.

In June 2013, we paid $106.4 million plus accrued interest, which included a premium of $6.4 million, to redeem $100.0 million of the outstanding 6⅜% Notes. The redemption resulted in a $7.4 million loss on debt redemption, including the write-off of $1.0 million of unamortized debt issuance costs.

In July 2013, we paid $76.8 million plus accrued interest, which included a premium of $4.1 million, per the terms of the note agreement to redeem the outstanding balance of the 11¼% Notes. The redemption resulted in a $7.4 million loss on debt redemption in the third quarter 2013, including the write-off of $1.0 million of unamortized debt issuance costs.

In October 2014, we privately placed $800.0 million in aggregate principal amount of 4⅛% Senior Notes due 2019 (the "4⅛% Notes"). The 4⅛% Notes resulted in approximately $790.8 million of net proceeds, which were used to reduce borrowings under the TRP Revolver and Securitization Facility and for general partnership purposes.

In November 2014, we redeemed the outstanding 7⅞% Notes at a price of 103.938% plus accrued interest through the redemption date. The redemption resulted in a $12.4 million loss on redemption for the year ended 2014, consisting of premiums paid of $9.9 million and a non-cash loss to write-off $2.5 million of unamortized debt issuance costs.

In January 2015, we 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% Notes"). The 5% Notes resulted in approximately $1,089.8 million of net proceeds after costs, which were used with borrowings under our senior secured credit facility to fund the APL Notes Tender Offers and the Change of Control Offer (each as defined below). The 5% Notes are unsecured senior obligations that have substantially the same terms and covenants as our other senior notes.

In September 2015, the Partnership Issuers issued $600 million in aggregate principal amount of 6¾% Senior Notes due 2024 (the "6¾% Notes"). The 6¾% Notes resulted in approximately $595.0 million of net proceeds after costs, which were used to reduce borrowings under our senior secured credit facility and for general partnership purposes. The 6¾% Notes are unsecured senior obligations that have substantially the same terms and covenants as our other senior notes.

Debt Repurchases

In December 2015, we repurchased on the open market a portion of outstanding Senior Notes as follows:

- 5¼% Notes due 2023 (the "5¼% Notes") paying $13.0 million plus accrued interest to repurchase $16.3 million of the outstanding balance of the 5¼% Notes.
- 4¼% Notes due 2023 (the "4¼% Notes") paying $1.2 million plus accrued interest to repurchase $1.5 million of the outstanding balance of the 4¼% Notes.
- 6⅝% APL Notes due 2020 (the "6⅝% Notes") paying $0.1 million plus accrued interest to repurchase $0.1 million of the outstanding balance of the 6⅝% Notes.

The December 2015 Senior note repurchases resulted in a $3.6 million gain on debt repurchases and a write-off of $0.1 million in related deferred debt issuance costs.

APL Merger Financing Activities

APL Senior Notes Tender Offers

In January 2015, we commenced cash tender offers for any and all of the outstanding fixed rate senior secured notes to be acquired in the APL merger, referred to as the APL Notes Tender Offers, which totaled $1.55 billion.

The results of the APL Notes Tender Offers were:

Senior Notes	Outstanding Note Balance	Amount Tendered	Premium Paid	Accrued Interest Paid	Total Tender Offer payments	% Tendered	Note Balance after Tender Offers
			($ amounts in millions)				
6⅝% due 2020	$ 500.0	$ 140.1	$ 2.1	$ 3.7	$ 145.9	28.02%	$ 359.9
4¾% due 2021	400.0	393.5	5.9	5.3	404.7	98.38%	6.5
5⅞% due 2023	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 APL Notes Tender Offers, on February 27, 2015, the supplemental indentures governing the 4¾% Senior Notes due 2021 (the "2021 APL Notes") and the 5⅞% Senior Notes due 2023 (the "2023 APL 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 APL Notes and the 2023 APL Notes that were not accepted for payment.

Not having achieved the minimum tender condition on the 6⅝% Senior Notes due 2020 of the APL Issuers (the "2020 APL Notes"), we made a change of control offer, referred to as the Change of Control Offer, for any and all of the 2020 APL 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 APL 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 APL Notes Tender Offers and Change of Control Offer totaling $1,168.8 million are presented as financing activities in the 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 APL 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, we had received tenders and consents from holders of approximately 96.3% of the total outstanding 2020 APL 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 APL 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 APL 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. We recognized $0.7 million of costs associated with the Exchange Offer, reflected as a Loss from financing activities on our Consolidated Statements of Operations.

Debt Repurchases Summary

The following table summarizes the debt repurchases that are included in our Consolidated Statements of Operations:

	2015	2014	2013
Premium over face value paid upon redemption:			
6⅜ Notes	$ -	$ -	$ 6.4
7⅞ Notes	-	9.9	-
11¼ Notes	-	-	4.1
Recognition of unamortized discount:			
11¼ Notes	-	-	2.2
Gain on repurchase of debt:			
5¼ Notes	(3.3)	-	-
4¼ Notes	(0.3)	-	-
Loss from financing with Exchange Offer:			
6⅝ Notes	0.7	-	-
Write-off of deferred debt issuance costs:			
5¼ Notes	0.1	-	-
6⅜ Notes	-	-	1.0
7⅞ Notes	-	2.5	-
11¼ Notes	-	-	1.0
(Gain) loss from financing activities	$ (2.8)	$ 12.4	$ 14.7

Selected terms of the senior unsecured notes outstanding as of December 31, 2015 were as follows:

Note Issue	Issue Date	Per Annum Interest Rate	Due Date	Dates Interest Paid
"6⅞% Notes"	February 2011	6⅞%	February 1, 2021	February & August 1st
"6⅜% Notes"	January 2012	6⅜%	August 1, 2022	February & August 1st
"5¼% Notes"	Oct / Dec 2012	5¼%	May 1, 2023	May & November 1st
"4¼% Notes"	May 2013	4¼%	November 15, 2023	May & November 15th
"4⅛% Notes"	October 2014	4⅛%	November 15, 2019	May & November 15th
"5% Notes"	January 2015	5%	January 15, 2018	January & July 15th
"6⅝% Notes"	May 2015	6⅝%	October 1, 2020	February & October 1st
"6¾% Notes"	September 2015	6¾%	March 15, 2024	March & September 15th
"APL 6⅝% Notes"	Sept 2012 (1)	6⅝%	October 1, 2020	April & October 1st
"APL 4¾% Notes"	May 2013 (1)	4¾%	November 15, 2021	May & November 15th
"APL 5⅞% Notes"	February 2013 (1)	5⅞%	August 1, 2023	February & August 1st

(1) Issue dates for APL Notes are original dates of issuance. These notes were acquired in the APL Merger. See Note 4 – Business Acquisitions.

All issues of unsecured senior notes are obligations that rank pari passu in right of payment 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 us and our restricted subsidiaries. These notes are effectively subordinated to all secured indebtedness under the TRP Revolver, which is secured by substantially all of our assets and our Securitization Facility, which is secured by accounts receivable pledged under the Securitization Facility, to the extent of the value of the collateral securing that indebtedness. Interest on all issues of senior unsecured notes is payable semi-annually in arrears.

Our senior unsecured notes and associated indenture agreements restrict our ability to make distributions to unitholders in the event of default (as defined in the indentures). The indentures also restrict our ability and the ability of certain of our subsidiaries to: (i) incur additional debt or enter into sale and leaseback transactions; (ii) pay certain distributions on or repurchase equity interests (only if such distributions do not meet specified conditions); (iii) make certain investments; (iv) incur liens; (v) enter into transactions with affiliates; (vi) merge or consolidate with another company; and (vii) transfer and sell assets. These covenants are subject to a number of important exceptions and qualifications. If at any time when the notes are rated investment grade by either Moody's Investors Service, Inc. ("Moody's)" or Standard & Poor's Corporation ("S&P") (or rated investment grade by both Moody's and S&P for the 6⅞% Notes) 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 we will cease to be subject to such covenants.

We may redeem up to 35% of the aggregate principal amount of Notes (other than with respect to the 5% Notes) 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 for the 6¾% Notes, 6⅜% Notes, 5¼% Notes, 4¼ % Notes and 4⅛% Notes of the date of the closing of such equity offering.

Note Issue	Any Date Prior To	Price
4¼% Notes	May 15, 2016	104.250%
6¾% Notes	September 15, 2018	106.750%
4⅛% Notes	November 15, 2017	104.125%

We 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.

6⅞% Notes		6⅜% Notes		5¼% Notes		4¼% Notes	
Redemption Date: February 1		Redemption Date: February 1		Redemption Date: November 1		Redemption Date: May 15	
Year	Price	Year	Price	Year	Price	Year	Price
2016	103.438%	2017	103.188%	2017	102.625%	2018	102.125%
2017	102.292%	2018	102.125%	2018	101.750%	2019	101.417%
2018	101.146%	2019	101.063%	2019	100.875%	2020	100.708%
2019 and thereafter	100%	2020 and thereafter	100%	2020 and thereafter	100%	2021 and thereafter	100%

6⅝% Notes		6¾% Notes		4⅛% Notes		APL 6⅝% Notes	
Redemption Date: October 1		Redemption Date: September 15		Redemption Date: November 15		Redemption Date: October 1	
Year	Price	Year	Price	Year	Price	Year	Price
2016	103.313%	2019	103.375%	2016	102.063%	2016	103.313%
2017	101.656%	2020	101.688%	2017	101.031%	2017	101.656%
2018 and thereafter	100.000%	2021 and thereafter	100.000%	2018 and thereafter	100%	2018 and thereafter	100%

APL 4¾% Notes		APL 5⅞% Notes	
Redemption Date: May 15		Redemption Date: February 1	
Year	Price	Year	Price
2016	103.563%	2018	102.938%
2017	102.375%	2019	101.958%
2018	101.188%	2020	100.979%
2019 and thereafter	100%	2021 and thereafter	100%

Accounts Receivable Securitization Facility

The Securitization Facility provides up to $225.0 million of borrowing capacity at LIBOR market index rates plus a margin through December 9, 2016. Under the Securitization Facility, subsidiaries sell or contribute qualifying receivables, without recourse, to TRLLC. TRLLC, in turn, sells an undivided percentage ownership in the eligible receivables to a third-party financial institution. Sold receivables up to the amount of the outstanding debt under the Securitization Facility are not available to satisfy the claims of the creditors of TLMT, TMS, TGM or us. Any excess receivables are eligible to satisfy the claims of creditors of the selling subsidiaries or us. Any excess receivables are eligible to satisfy the creditor claims. As of December 31, 2015, total funding under the Securitization Facility was $219.3 million.

April 2013 Shelf

In April 2013, we filed with the SEC a universal shelf registration statement (the “April 2013 Shelf”), which provides us with the ability to offer and sell an unlimited amount of debt and equity securities, subject to market conditions and our capital needs. The April 2013 Shelf expires in April 2016. There was no activity under the April 2013 Shelf during the years ended December 31, 2015 and 2014.

July 2013 Shelf

In July 2013, we filed with the SEC a universal shelf registration statement that allows us to issue up to an aggregate of $800.0 million of debt or equity securities (the “July 2013 Shelf”). The July 2013 Shelf expires in August 2016. See Note 11 – Partnership Units and Related Matters for equity issuances under the July 2013 Shelf.

April 2015 Shelf

In April 2015, we filed with the SEC a universal shelf registration statement that allows us to issue up to an aggregate of $1.0 billion of debt or equity securities (the "April 2015 Shelf"). The April 2015 Shelf expires in April 2018.

Subsequent Events

As of February 18, 2016, we repurchased on the open market a portion of outstanding Senior Notes as follows:

- 5¼% Senior Notes due 2023 (the “5¼% Notes”) paying 16.7 million plus accrued interest to repurchase $20.5 million of the outstanding balance of the 5¼% Notes.

- 4¼% Senior Notes due 2023 (the “4¼% Notes”) paying $17.0 million plus accrued interest to repurchase $22.9 million of the outstanding balance of the 4¼% Notes.

- 6⅞% Senior Notes due 2021 (the “6⅞% Notes”) paying $4.3 million plus accrued interest to repurchase $5.0 million of the outstanding balance of the 6⅞% Notes.

- 6⅝% Senior Notes due 2020 (the “6⅝% Notes”) paying $15.3 million plus accrued interest to repurchase $17.4 million of the outstanding balance of the 6⅝% Notes.

- 6⅜% Senior Notes due 2022 (the “6⅜% Notes”) paying $7.6 million plus accrued interest to repurchase $9.5 million of the outstanding balance of the 6⅜% Notes.

- 6¾% Senior Notes due 2024 (the “6¾% Notes”) paying $2.4 million plus accrued interest to repurchase $3.0 million of the outstanding balance of the 6¾% Notes.

- 5% Senior Notes due 2018 (the “5% Notes”) paying $1.5 million plus accrued interest to repurchase $1.9 million of the outstanding balance of the 5% Notes.

- 4⅛% Senior Notes due 2019 (the “4⅛%Notes”) paying $11.9 million plus accrued interest to repurchase $16.4 million of the outstanding balance of the 4⅛% Notes.

We paid a total of $0.2 million in fees and $1.4 million in accrued interest for the repurchase of these Senior Notes.

Note 10 — Other Long-term Liabilities

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

	December 31,	
	2015	**2014**
Asset retirement obligations	$ 69.9	$ 56.8
Mandatorily redeemable preferred interests	82.9	-
Deferred revenue and other	25.4	1.0
Total long-term liabilities	$ 178.2	$ 57.8

Asset Retirement Obligations

Our asset retirement obligations ("ARO") primarily relate to certain gas gathering pipelines and processing facilities, and are included in our consolidated balance sheets as a component of other long-term liabilities. The changes in our ARO are as follows:

	2015	2014	2013
Beginning of period	$ 56.8	$ 50.5	$ 45.2
Fair value of ARO acquired with the APL merger	4.0	-	-
Change in cash flow estimate	3.8	2.1	1.4
Accretion expense	5.3	4.4	3.9
Retirement of ARO	-	(0.2)	-
End of period	$ 69.9	$ 56.8	$ 50.5

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 period ending on December 31, 2015, interest earned on the notes receivable of $8.9 million, exclusive of the priority return payable to our partner, is reflected within Interest expense, net on 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. Our estimate was not derived using the explicit valuation procedures required under the joint venture agreements which, at the earliest, would be required in 2022 and, as such, the actual value of our partner's allocable share each joint venture's assets may differ from our estimate.

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 as Other long-term liabilities of $82.9 million as of December 31, 2015. Aggregate changes in the fair values of the notes receivable and the estimated redemption value of the mandatorily redeemable preferred interests in the WestTX and WestOK joint ventures resulted in income of $30.6 million within interest expense, net on the Consolidated Statement of Operations for the year ended December 31, 2015.

The following table shows the changes in long-term liabilities attributable to mandatorily redeemable preferred interests:

	Liability attributable to mandatorily redeemable preferred interests
Balance at December 31, 2014	-
Acquired mandatorily redeemable preferred interests	$ 109.3
Change in estimated redemption value	(30.6)
Income attributable to mandatorily redeemable preferred interests	2.8
Other activity, net	1.4
Balance at December 31, 2015	$ 82.9

Deferred Revenue and Other

Deferred revenue and other includes consideration received in a 2015 amendment to a gas gathering and processing agreement which requires future performance by Targa. The consideration paid for the contract amendment will require future performance by Targa which has resulted in the deferred revenue. The deferred revenue will be recognized on a straight-line basis through the end of the agreement's term in 2030. As of December 31, 2015, the balance of deferred revenue is $21.1 million. For the year ended December 31, 2015, we recognized approximately $1.4 million of revenue for this transaction. See Note 21 – Supplemental Cash Flow Information.

Note 11 — Partnership Units and Related Matters

Public Offerings of Common Units

In July 2012, we filed with the SEC a universal shelf registration statement that, subject to effectiveness at the time of use, allows us to issue up to an aggregate of $300.0 million of debt or equity securities (the “2012 Shelf”). The 2012 Shelf expired in August 2015.

In August 2012, we entered into an Equity Distribution Agreement (the “2012 EDA”) with Citigroup Global Markets Inc. (“Citigroup”) pursuant to which we may sell, at our option, up to an aggregate of $100.0 million of our common units through Citigroup, as sales agent, under the 2012 Shelf. During the year ended December 31, 2013, we issued 2,420,046 common units under the 2012 EDA, receiving net proceeds of $94.8 million. Targa contributed $2.0 million to us to maintain its 2% general partner interest.

In March 2013, we entered into a second Equity Distribution Agreement under the 2012 Shelf (the “March 2013 EDA”) with Citigroup, Deutsche Bank Securities Inc. (“Deutsche Bank”), Raymond James & Associates, Inc. (“Raymond James”) and UBS Securities LLC (“UBS”), as our sales agents, pursuant to which we may sell, at our option, up to an aggregate of $200.0 million of our common units. During the year ended December 31, 2013 we issued 4,204,751 common units receiving net proceeds of $197.5 million. Targa contributed $4.1 million to maintain its 2% general partner interest.

In August 2013, we entered into an Equity Distribution Agreement under the July 2013 Shelf (the “August 2013 EDA”) with Citigroup, Deutsche Bank, Morgan Stanley & Co. LLC (“Morgan Stanley”), Raymond James, RBC Capital Markets, LLC (“RBC”), UBS and Wells Fargo Securities, LLC (“Wells Fargo”), as our sales agents, pursuant to which we may sell, at our option, up to an aggregate of $400.0 million of our common units. During the year ended 2013, we issued 4,259,641 common units under the August 2013 EDA, receiving net proceeds of $225.6 million. Targa contributed $4.7 million to us to maintain its 2% general partner interest.

In May 2014, we entered into an additional equity distribution agreement under our July 2013 Shelf (the “May 2014 EDA”), with Barclays Capital Inc., Citigroup, Deutsche Bank, Jefferies LLC, Morgan Stanley, Raymond James, RBC, UBS and Wells Fargo, as our sales agents, pursuant to which we may sell, at our option, up to an aggregate of $400 million of our common units.

During the year ended 2014, pursuant to the August 2013 EDA and the May 2014 EDA, we issued a total of 7,175,096 common units representing total net proceeds of $408.4 million, (net of commissions up to 1% of gross proceeds to our sales agent), which were used to reduce borrowings under the TRP Revolver and for general partnership purposes. Targa contributed $8.4 million to us to maintain its 2% general partner interest.

In May 2015, we entered into an additional Equity Distribution Agreement under the April 2015 Shelf (the “May 2015 EDA”), pursuant to which we may sell through our sales agents, at our option, up to an aggregate of $1.0 billion of our common units. As of December 31, 2015,, we issued 7,377,380 common units under our 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 remain under the May 2014 and May 2015 EDAs. As of December 31, 2015, Targa contributed $6.5 million to us to maintain its 2% general partner interest.

Pursuant to the TRC/TRP Merger Agreement, TRC has agreed to cause 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.

Issuances of Common Units

As part of the Atlas merger, we 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 Targa. Targa contributed $52.4 million to us to maintain its 2% general partner interest.

Issuance of Preferred Units

In October 2015, under our automatic shelf registration statement filed in April 2013 and amended by a post-effective amendment filed in October 2015 (the "April 2013 Shelf"), we 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, we sold an additional 600,000 Preferred Units at a price of $25.00 per unit. We received net proceeds after costs of approximately $121.1 million. We used the net proceeds from this offering to reduce borrowings under our 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 Preferred Units are cumulative from the date of original issue and are payable monthly in arrears on the 15th day of each month of each year, when, as and if declared by the board of directors of our general partner. Distributions on the Preferred Units will be 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 will, with respect to anticipated monthly distributions, rank:

- senior to our common units and to each other class or series of Partnership interests or other equity securities established after the original issue date of the Preferred Units that is not expressly made senior to or pari passu with the Preferred Units as to the payment of distributions;

- pari passu with any class or series of Partnership interests or other equity securities established after the original issue date of the Preferred Units that is not expressly made senior or subordinated to the Preferred Units as to the payment of distributions;

- junior to all of our existing and future indebtedness (including (i) indebtedness outstanding under our senior secured credit facility, (ii) our 5% Notes, our 4⅛% Notes, our 6⅝% Notes, our 6⅞% Senior Notes due 2021, our 6⅜% Senior Notes due 2022, our 5¼% Senior Notes due 2023, our 4¼% Senior Notes due 2023 and our 6¾% Notes and (iii) indebtedness outstanding under our Securitization Facility and other liabilities with respect to assets available to satisfy claims against us; and

- junior to each other class or series of Partnership interests or other equity securities established after the original issue date of the Preferred Units that is expressly made senior to the Preferred Units as to the payment of distributions.

At any time on or after November 1, 2020, we may redeem the Preferred Units, in whole or in part, from any source of funds legally available for such purpose, by paying $25.00 per unit plus an amount equal to all accumulated and unpaid distributions thereon to the date of redemption, whether or not declared. In addition, we (or a third party with our prior written consent) may redeem the Preferred Units following certain changes of control, as described in our Partnership Agreement. If we do not (or a third party with our prior written consent does not) exercise this option, then the holders of the Preferred Units have the option to convert the Preferred Units into a number of common units per Preferred Unit as set forth in our partnership agreement. If we exercise (or a third party with our prior written consent exercises) our redemption rights relating to any Preferred Units, the holders of those Preferred Units will not have the conversion right described above with respect to the Preferred Units called for redemption. Holders of Preferred Units have no voting rights except for certain exceptions set forth in our Partnership Agreement.

As of December 31, 2015, we have paid $1.5 million in distributions to our preferred unitholders.

Distributions

In accordance with the Partnership Agreement, we must distribute all of our available cash, as determined by the general partner, to common unitholders of record within 45 days after the end of each quarter. The following table details the distributions declared and/or paid by us during the periods presented. As a result of the TRC/TRP Merger, which was completed on February 17, 2016, Targa owns all of our outstanding common units.

Three Months Ended	Date Paid	Distributions: Limited Partners: Common	General Partner: Incentive Distribution Rights	General Partner: 2%	Total	Distributions per Limited Partner Unit
		(In millions, except per unit amounts)				
December 31, 2015	February 9, 2016	$ 152.5	$ 43.9 (1)	$ 4.0	$ 200.4	$ 0.8250
September 30, 2015	November 13, 2015	152.5	43.9 (1)	4.0	200.4	0.8250
June 30, 2015	August 14, 2015	152.5	43.9 (1)	4.0	200.4	0.8250
March 31, 2015	May 15, 2015	148.3	41.7 (1)	3.9	193.9	0.8200
2014						
December 31, 2014	February 13, 2015	96.3	38.4	2.7	137.4	0.8100
September 30, 2014	November 14, 2014	92.3	36.0	2.6	130.9	0.7975
June 30, 2014	August 14, 2014	89.5	33.7	2.5	125.7	0.7800
March 31, 2014	May 15, 2014	87.2	31.7	2.4	121.3	0.7625
2013						
December 31, 2013	February 14, 2014	84.0	29.5	2.3	115.8	0.7475
September 30, 2013	November 14, 2013	79.4	26.9	2.2	108.5	0.7325
June 30, 2013	August 14, 2013	75.8	24.6	2.0	102.4	0.7150
March 31, 2013	May 15, 2013	71.7	22.1	1.9	95.7	0.6975

(1) Pursuant to the IDR Giveback Amendment in conjunction with the Atlas mergers, IDRs of $9.375 million were allocated to common unitholders in each of the quarters for 2015. The IDR Giveback Amendment covers sixteen quarterly distribution declarations following the completion of the Atlas mergers on February 27, 2015 and resulted in reallocation of IDR payments to common unitholders in the following amounts: $9.375 million per quarter for 2015. The IDR Giveback will result in reallocation of IDR payments to common unitholders of $6.25 million in the first quarter of 2016.

Note 12 — Earnings per Limited Partner Unit

The following table sets forth a reconciliation of net income (loss) and weighted average shares outstanding used in computing basic and diluted net income (loss) per limited partner unit:

	2015	2014	2013
Net income (loss)	$ (59.3)	$ 505.1	$ 258.6
Less: Net income attributable to noncontrolling interests	(31.9)	37.4	25.1
Net income (loss) attributable to Targa Resources Partners LP	$ (27.4)	$ 467.7	$ 233.5
Net income attributable to preferred limited partners	$ 2.4	$ -	$ -
Net income attributable to general partner	167.7	148.7	107.5
Net income (loss) attributable to limited partners	(197.5)	319.0	126.0
Net income (loss) attributable to Targa Resources Partners LP	$ (27.4)	$ 467.7	$ 233.5
Weighted average units outstanding - basic	172.3	114.7	105.5
Net income (loss) available per limited partner unit - basic	$ (1.15)	$ 2.78	$ 1.19
Weighted average units outstanding	172.3	114.7	105.5
Dilutive effect of unvested stock awards	-	0.4	0.2
Weighted average units outstanding - diluted (1)	172.3	115.1	105.7
Net income (loss) available per limited partner unit - diluted	$ (1.15)	$ 2.77	$ 1.19

(1) For the year ended December 31, 2015 and 2014, approximately 697,989 and 168,495 units were excluded from the computation of diluted earnings attributable to common limited partners per unit because the inclusion of such units would have been anti-dilutive.

Note 13 — Derivative Instruments and Hedging Activities

Commodity Hedges

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 equity volumes in our Field Gathering and Processing segment and (ii) NGL and condensate equity volumes predominately in our Field Gathering and Processing segment and the LOU business unit in our Coastal Gathering and Processing segment that result from percent-of-proceeds processing arrangements. 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 necessarily 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 APL derivative contracts with a fair value of $102.1 million as of the acquisition date were novated to the Partnership and included in the acquisition date fair value of assets acquired. Derivative settlements of $67.9 million related to these novated contracts were received during the year ended December 31, 2015 and were reflected as a reduction of the acquisition date fair value of the APL derivative assets acquired, with 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. Certain novated APL crude options with a fair value of $7.7 million as of the acquisition date did not fall within the “highly effective” correlation range required to qualify as a hedging instrument for accounting purposes. These non-qualifying hedges were settled in December 2015, which resulted in a $2.2 million gain on cash settlement for the year ended December 31, 2015. Additionally, for the year ended December 31, 2015, we recorded $0.9 million of ineffectiveness gains related to otherwise qualifying APL derivatives, primarily natural gas swaps.

At December 31, 2015, the notional volumes of our commodity derivative contracts were:

Commodity	Instrument	Unit	2016	2017	2018
Natural Gas	Swaps	MMBtu/d	83,264	23,082	-
Natural Gas	Basis Swaps	MMBtu/d	48,962	18,082	-
Natural Gas	Collars	MMBtu/d	22,900	22,900	9,486
NGL	Swaps	Bbl/d	4,473	1,078	208
NGL	Futures	Bbl/d	1,956	-	-
NGL	Options/Collars	Bbl/d	920	920	32
Condensate	Swaps	Bbl/d	1,502	500	-
Condensate	Options/Collars	Bbl/d	790	790	101

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 we record changes in fair value and cash settlements to revenues.

Our derivative contracts are subject to netting arrangements that permit our contracting subsidiaries to net cash settle offsetting asset and liability positions with the same counterparty within the same Targa entity. We record derivative assets and liabilities on our Consolidated Balance Sheets on a gross basis, without considering the effect of master netting arrangements. The following schedules reflect the fair values of our derivative instruments and their location in our Consolidated Balance Sheets as well as pro forma reporting assuming that we reported derivatives subject to master netting agreements on a net basis:

		Fair Value as of December 31, 2015		Fair Value as of December 31, 2014	
	Balance Sheet Location	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Derivatives designated as hedging instruments					
Commodity contracts	Current	$ 92.1	$ 2.1	$ 44.4	$ -
	Long-term	34.9	2.4	15.8	-
Total derivatives designated as hedging instruments		$ 127.0	$ 4.5	$ 60.2	$ -
Derivatives not designated as hedging instruments					
Commodity contracts	Current	$ 0.1	$ 3.1	$ -	$ 5.2
Total derivatives not designated as hedging instruments		$ 0.1	$ 3.1	$ -	$ 5.2
Total current position		$ 92.2	$ 5.2	$ 44.4	$ 5.2
Total long-term position		34.9	2.4	15.8	-
Total derivatives		$ 127.1	$ 7.6	$ 60.2	$ 5.2

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

	Gross Presentation		Pro Forma Net Presentation	
December 31, 2015	Asset Position	Liability Position	Asset Position	Liability Position
Current position				
Counterparties with offsetting position	$ 86.9	$ 5.2	$ 81.7	$ -
Counterparties without offsetting position - assets	5.3	-	5.3	-
Counterparties without offsetting position - liabilities	-	-	-	-
	92.2	5.2	87.0	-
Long-term position				
Counterparties with offsetting position	34.2	2.4	31.8	-
Counterparties without offsetting position - assets	0.7	-	0.7	-
Counterparties without offsetting position - liabilities	-	-	-	-
	34.9	2.4	32.5	-
Total derivatives				
Counterparties with offsetting position	121.1	7.6	113.5	-
Counterparties without offsetting position - assets	6.0	-	6.0	-
Counterparties without offsetting position - liabilities	-	-	-	-
	$ 127.1	$ 7.6	$ 119.5	$ -
December 31, 2014				
Current position				
Counterparties with offsetting position	$ 35.5	$ 4.4	$ 31.1	$ -
Counterparties without offsetting position - assets	8.9	-	8.9	-
Counterparties without offsetting position - liabilities	-	0.8	-	0.8
	44.4	5.2	40.0	0.8
Long-term position				
Counterparties with offsetting position	-	-	-	-
Counterparties without offsetting position - assets	15.8	-	15.8	-
Counterparties without offsetting position - liabilities	-	-	-	-
	15.8	-	15.8	-
Total derivatives				
Counterparties with offsetting position	35.5	4.4	31.1	-
Counterparties without offsetting position - assets	24.7	-	24.7	-
Counterparties without offsetting position - liabilities	-	0.8	-	0.8
	$ 60.2	$ 5.2	$ 55.8	$ 0.8

Our payment obligations in connection with substantially all of these hedging transactions are secured by a first priority lien in the collateral securing our senior secured indebtedness that ranks equal in right of payment with liens granted in favor of our senior secured lenders. Some of our hedges are futures contracts executed through a counterparty that clears the hedges through an exchange. The payment obligations on these futures are settled daily.

The fair value of our derivative instruments, depending on the type of instrument, was determined by the use of present value methods or standard option valuation models with assumptions about commodity prices based on those observed in underlying markets. The estimated fair value of our derivative instruments was a net asset of $119.5 million as of December 31, 2015. The estimated fair value is net of an adjustment for credit risk based on the default probabilities by year as indicated by market quotes for the counterparties' credit default swap rates. The credit risk adjustment was immaterial for all periods presented. Our futures contracts that are cleared through an exchange are settled daily and do not require any credit adjustment.

The following tables reflect amounts recorded in Other Comprehensive Income ("OCI") and amounts reclassified from OCI to revenue and expense for the periods indicated:

	Gain (Loss) Recognized in OCI on Derivatives (Effective Portion)		
Derivatives in Cash Flow Hedging Relationships	**2015**	**2014**	**2013**
Commodity contracts	$ 81.3	$ 59.8	$ (5.8)

	Gain (Loss) Reclassified from OCI into Income (Effective Portion)		
Location of Gain (Loss)	**2015**	**2014**	**2013**
Interest expense, net	$ -	$ (2.4)	$ (6.1)
Revenues	54.8	(4.2)	21.2
	$ 54.8	$ (6.6)	$ 15.1

Our consolidated earnings are also affected by our use of the mark-to-market method of accounting for derivative instruments that do not qualify for hedge accounting or that have not been designated as hedges. The changes in fair value of these instruments are recorded on the balance sheet and through earnings rather than being deferred until the anticipated transaction settles. The use of mark-to-market accounting for financial instruments can cause non-cash earnings volatility due to changes in the underlying commodity price indices.

		Gain (Loss) Recognized in Income on Derivatives		
Derivatives Not Designated as Hedging Instruments	**Location of Gain Recognized in Income on Derivatives**	**2015**	**2014**	**2013**
Commodity contracts	Revenue	$ (5.7)	$ (5.5)	$ (0.1)

The following table shows the deferred gains (losses) included in accumulated OCI, which will be reclassified into earnings through the end of 2018 as of the balance sheet date:

	December 31, 2015	**December 31, 2014**
Commodity hedges (1)	$ 86.7	$ 60.3

(1) Includes deferred net gains of $52.1 million as of December 31, 2015 related to contracts that will be settled and reclassified to revenue over the next 12 months.

See Note 14 – Fair Value Measurements for additional disclosures related to derivative instruments and hedging activities.

Note 14 — Fair Value Measurements

Under GAAP, our Consolidated Balance Sheets reflect a mixture of measurement methods for financial assets and liabilities ("financial instruments"). Derivative financial instruments and contingent consideration related to business acquisitions are reported at fair value in our Consolidated Balance Sheets. Other financial instruments are reported at historical cost or amortized cost in our Consolidated Balance Sheets. The following are additional qualitative and quantitative disclosures regarding fair value measurements of financial instruments.

Fair Value of Derivative Financial Instruments

Our derivative instruments consist of financially settled commodity swaps, futures, option contracts and fixed-price forward commodity contracts with certain counterparties. We determine the fair value of our derivative contracts using present value methods or standard option valuation models with assumptions about commodity prices based on those observed in underlying markets. We have consistently applied these valuation techniques in all periods presented and 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. This financial position of these derivatives at December 31, 2015, a net asset position of $119.5 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 asset of $99.8 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 $138.1 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 senior secured revolving credit facility (the "TRP Revolver") and the Securitization Facility are based on carrying value, which approximates fair value as their interest rates are based on prevailing market rates; and

- Senior unsecured notes are based on quoted market prices derived from trades of the debt.

We have a contingent consideration liability for APL's previous acquisition of a gas gathering system and related assets, which is carried at fair value (see Note 4 – Business Acquisitions).

Fair Value Hierarchy

We categorize the inputs to the fair value measurements of financial assets and liabilities using a three-tier fair value hierarchy that prioritizes the significant inputs used in measuring fair value:

- Level 1 – observable inputs such as quoted prices in active markets;

- Level 2 – inputs other than quoted prices in active markets that we can directly or indirectly observe to the extent that the markets are liquid for the relevant settlement periods; and

- Level 3 – unobservable inputs in which little or no market data exists, therefore we must develop our own assumptions.

The following table shows a breakdown by fair value hierarchy category for (1) financial instruments measurements included in our Consolidated Balance Sheets at fair value and (2) supplemental fair value disclosures for other financial instruments:

	December 31, 2015				
	Carrying Value	Fair Value			
		Total	Level 1	Level 2	Level 3
Financial Instruments Recorded on Our Consolidated Balance Sheets at Fair Value:					
Assets from commodity derivative contracts (1)	$ 127.1	$ 127.1	$ -	$ 123.1	4.0
Liabilities from commodity derivative contracts (1)	7.6	7.6	0.3	7.0	0.3
TPL contingent consideration (2)	3.0	3.0	-	-	3.0
Financial Instruments Recorded on Our Consolidated Balance Sheets at Carrying Value:					
Cash and cash equivalents	135.4	135.4	-	-	-
Senior secured revolving credit facility	280.0	280.0	-	280.0	-
Senior unsecured notes	4,884.0	4,192.0	-	4,192.0	-
Accounts receivable securitization facility	219.3	219.3	-	219.3	-

	December 31, 2014				
	Carrying Value	Fair Value			
		Total	Level 1	Level 2	Level 3
Financial Instruments Recorded on Our Consolidated Balance Sheets at Fair Value:					
Assets from commodity derivative contracts	$ 60.2	$ 60.2	$ -	$ 58.4	$ 1.8
Liabilities from commodity derivative contracts	5.2	5.2	-	5.1	0.1
Financial Instruments Recorded on Our Consolidated Balance Sheets at Carrying Value:					
Cash and cash equivalents	72.3	72.3	-	-	-
Senior secured revolving credit facility	-	-	-	-	-
Senior unsecured notes	2,783.4	2,731.5	-	2,731.5	-
Accounts receivable securitization facility	182.8	182.8	182.8	-	-

(1) The fair value of our derivative contracts in this table is presented on a different basis than the Consolidated Balance Sheets presentation as disclosed in Note 13 – 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) See Note 4 – Business Acquisitions.

Additional Information Regarding Level 3 Fair Value Measurements Included in Our Consolidated Balance Sheets

We reported certain of our swaps and option contracts at fair value using Level 3 inputs due to such derivatives not having observable 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 natural gas 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, 2015, 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 the forward natural gas curves, for which a significant portion of the derivative's term is beyond available forward pricing. 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 contingent consideration was determined using a probability-based model measuring the likelihood of meeting certain volumetric measures. These probability-based inputs are not observable; the entire valuation of the contingent consideration is categorized in Level 3. Changes in the fair value of this liability are included in Other Income on the Consolidated Statements of Operations.

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

	Commodity Derivative Contracts (Asset)/Liability	Contingent Liability
Balance, December 31, 2012	$ 0.6	$ 15.3
Settlements included in Revenue	(1.3)	-
Change in valuation of contingent liability included in Other Income	-	(15.3)
Balance, December 31, 2013	(0.7)	-
Settlements included in Revenue	(0.2)	-
Unrealized losses included in OCI	(1.1)	-
Transfers out of Level 3	0.3	-
Balance, December 31, 2014	(1.7)	-
TPL contingent consideration fair value at acquisition date (see Note 4-Business Acquisitions)	-	4.2
Change in fair value of TPL contingent consideration included in Other Income	-	(1.2)
New Level 3 instruments	(3.7)	-
Transfers out of Level 3	1.7	-
Balance, December 31, 2015	$ (3.7)	$ 3.0

For the year ended December 31, 2015, the Partnership transferred $1.7 million in derivative liabilities out of Level 3 and into Level 2. These transfers relate to long-term over-the-counter swaps for natural gas and NGL products with deliveries for which observable market prices were available.

Note 15 — Related Party Transactions

Relationship with Targa

We do not have any employees. Targa provides operational, general and administrative and other services to us associated with our existing assets and assets acquired from third parties. Targa performs centralized corporate functions for us, such as legal, accounting, treasury, insurance, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes, engineering and marketing.

Our Partnership Agreement governs the reimbursement of costs incurred by Targa on behalf of us. Targa charges us for all the direct costs of the employees assigned to our operations, as well as all general and administrative support costs other than (1) costs attributable to Targa's status as a separate reporting company and (2) costs of Targa providing management and support services to certain unaffiliated spun-off entities. We generally reimburse Targa monthly for cost allocations to the extent that Targa has made a cash outlay.

The following table summarizes transactions with Targa. Management believes these transactions are executed on terms that are fair and reasonable.

	2015	2014	2013
Targa billings of payroll and related costs included in operating expense	$ 153.8	$ 124.9	$ 109.7
Targa allocation of general and administrative expense	136.2	129.4	134.3
Cash distributions to Targa based on IDR and unit ownership	233.4	180.7	138.2
Cash contributions from Targa to maintain its 2% general partner ownership	60.1	7.7	10.8

Transactions with Unconsolidated Affiliates

For the years ended December 31, 2015, 2014 and 2013, transactions with GCF included in revenues were $0.5 million, $0.8 million and $0.4 million. For the same periods, transactions with GCF included in costs and expenses were $5.8 million, $7.6 million and $6.3 million. The Partnership is subject to paying a deficiency fee in instances where the Partnership does not deliver its minimum volume requirements as outlined in the Partnership and fractionation agreements with GCF.

For the year ended December 31, 2015, capacity lease fees paid to T2 Eagle Ford and T2 LaSalle included in operating expenses were $2.8 million and $1.1 million, respectively. These fees are billed to the Partnership based on its portion of the cost to operate each respective joint venture. As of December 31, 2015, the Partnership had a $1.8 million payable to T2 Eagle Ford for capital project cash calls and accrued lease capacity fees.

Note 16 — Commitments (Leases)

Future lease obligations are presented below in aggregate and for each of the next five fiscal years.

	In Aggregate	2016	2017	2018	2019	2020
Operating leases (1)	$ 42.1	$ 16.0	$ 10.8	$ 8.8	$ 3.7	$ 2.8
Land site lease and right-of-way (2)	11.0	2.4	2.3	2.2	2.1	2.0
	$ 53.1	$ 18.4	$ 13.1	$ 11.0	$ 5.8	$ 4.8

(1) Includes minimum payments on lease obligations for office space, railcars and tractors.
(2) Land site lease and right-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 were:

	2015	2014	2013
Operating leases (1)	$ 40.4	$ 24.4	$ 23.3
Land site lease and right-of-way	4.2	4.1	3.6

(1) Includes short-term leases for items such as compressors and equipment.

Note 17 - Contingencies

Legal Proceedings

Litigation related to TRC/TRP Merger

On December 16, 2015, two purported unitholders of TRP (the “State Court Plaintiffs”) filed a putative class action and derivative lawsuit challenging the TRC/TRP Merger against TRC, TRP (as a nominal defendant), TRP GP, the members of the board of our general partner (the “TRP GP Board”) and Merger Sub (collectively, the “State Court Defendants”). This lawsuit is styled *Leslie Blumberg et al. v. TRC Resources Corp., et al.*, Cause No. 2015-75481, in the District Court of Harris County, Texas, 234th Judicial District (the “State Court Lawsuit”).

The State Court Plaintiffs allege several causes of action challenging the TRC/TRP Merger. Generally, the State On December 16, 2015, two purported unitholders of TRP (the “State Court Plaintiffs”) filed a putative class action and derivative lawsuit challenging the TRC/TRP Merger against TRC, TRP (as a nominal defendant), TRP GP, the members of the board of our general partner (the “TRP GP Board”) and Merger Sub (collectively, the “State Court Defendants”). This lawsuit is styled *Leslie Blumberg et al. v. TRC Resources Corp., et al.*, Cause No. 2015-75481, in the District Court of Harris County, Texas, 234th Judicial District (the “State Court Lawsuit”).

The State Court Plaintiffs allege several causes of action challenging the TRC/TRP Merger. Generally, the State Court Plaintiffs allege that (i) the members of the TRP GP Board breached express and/or implied duties under the TRP partnership agreement and (ii) TRC, our general partner, and Merger Sub aided and abetted in these alleged breaches of duties. The State Court Plaintiffs further allege, in general, that (a) the premium offered to TRP’s unitholders was inadequate, (b) the TRC/TRP Merger did not include a collar to protect TRP unitholders from decreases in TRC’s stock price, (c) the TRP GP Board agreed to contractual terms that allegedly may have dissuaded other potential acquirers from seeking to acquire TRP (including the “no-solicitation,” “matching rights,” and “termination fee” provisions), (d) the process leading up to the TRC/TRP Merger was unfair and (e) the TRP GP Board has conflicts of interest due to TRC’s control of our general partner.

Based on these allegations, the State Court Plaintiffs sought to enjoin the State Court Defendants from proceeding with or consummating the TRC/TRP Merger unless and until the TRP GP Board adopted and implemented processes to obtain the best possible terms for TRP common unitholders. The State Court Plaintiffs now seek to have the TRC/TRP Merger rescinded. The date to answer or otherwise respond to the State Court Lawsuit is currently set for February 29, 2016.

On January 6 and 19, 2016, two additional purported unitholders of TRP (the “Federal Court Plaintiffs”) filed two putative class action lawsuits challenging the disclosures made in connection with the TRC/TRP Merger against TRP and the members of the TRP GP Board (the “Federal Court Defendants”). These lawsuits have been consolidated as *In re Targa Resources Partners, L.P. Securities Litigation*, Consolidated C.A. No. 4:16-cv-00041, in the United States District Court for the Southern District of Texas, Houston Division (the “Federal Court Lawsuits”).

The Federal Court Plaintiffs allege that (i) the Federal Court Defendants have violated Section 14(a) of the Exchange Act and Rule 14a-9 promulgated thereunder and (ii) the members of the TRP GP Board have violated Section 20(a) of the Exchange Act. The Federal Court Plaintiffs allege, in general, that the preliminary and definitive joint proxy statements/prospectuses filed in connection with the TRC/TRP Merger fail, among other things, to disclose allegedly material information concerning (i) the TRP GP Conflicts Committee’s financial advisor’s and TRC’s financial advisor’s analyses in connection with the TRC/TRP Merger, (ii) certain TRC and TRP projections, and (iii) the events leading up to the TRC/TRP Merger. The Federal Court Plaintiffs further allege, in general, that (a) the premium offered to TRP’s unitholders was inadequate, (b) the TRC/TRP Merger did not include a collar to protect TRP unitholders from decreases in TRC’s stock price, (c) the TRP GP Board agreed to contractual terms that allegedly may have dissuaded other potential acquirers from seeking to acquire TRP (including the “no-solicitation,” “matching rights,” and “termination fee” provisions), (d) the process leading up to the TRC/TRP Merger was unfair and (e) the TRP GP Board has conflicts of interest due to TRC’s control of the general partner.

Based on these allegations, the Federal Court Plaintiffs sought to enjoin the Federal Court Defendants from proceeding with or consummating the TRC/TRP Merger unless and until the Federal Court Defendants disclosed the allegedly omitted information summarized above. The Federal Court Plaintiffs now seek to have the TRC/TRP Merger rescinded. The Federal Court Plaintiffs also seek damages and attorneys’ fees.

One of the Federal Court Plaintiffs sought a Temporary Restraining Order ("TRO") to prevent the Federal Court Defendants from proceeding with the TRC/TRP vote and/or merger. On January 29, 2016, this Plaintiff was denied his request for a TRO.

The date for the Federal Court Defendants to answer, move to dismiss, or otherwise respond to the Federal Court Lawsuits has not yet been set.

Neither the State Court Defendants nor the Federal Court Defendants (collectively, the "Defendants") can predict the outcome of these or any other lawsuits that might be filed subsequent to the date of the filing of this report, nor can Defendants predict the amount of time and expense that will be required to resolve such litigation. Defendants believe these lawsuits are without merit and intend to defend vigorously against these lawsuits and any other actions challenging the TRC/TRP Merger.

Targa Litigation related to Atlas Mergers

On January 28, 2015, a public shareholder of TRC (the "TRC Plaintiff") filed a putative class action and derivative lawsuit against TRC (as a nominal defendant), its directors at the time of the ATLS Merger (the "TRC Director Defendants"), and ATLS (together with TRC and the TRC Director Defendants, the "TRC Lawsuit Defendants"). This lawsuit was styled *Inspired Investors v. Joe Bob Perkins, et al.*, in the District Court of Harris County, Texas (the "TRC Lawsuit").

The TRC Plaintiff alleged a variety of causes of action challenging the disclosures related to the ATLS Merger. Generally, the TRC Plaintiff alleged that the TRC Director Defendants breached their fiduciary duties. The TRC Plaintiff further alleged that the registration statement filed on January 22, 2015 failed to disclose allegedly material details concerning (i) Wells Fargo Securities, LLC's and the TRC Director Defendants' supposed conflicts of interest with respect to the ATLS Merger, (ii) TRC's financial projections, (iii) the background of the ATLS Merger, and (iv) Wells Fargo Securities, LLC's analysis of the ATLS Merger.

Based on these allegations, the TRC Plaintiff sought to enjoin the TRC Lawsuit Defendants from proceeding with or consummating the ATLS Merger unless and until TRC disclosed the allegedly material omitted details. The TRC Plaintiff also sought to have the ATLS Merger rescinded, recissory damages, and attorneys' fees.

On June 9, 2015, the Court dismissed the TRC Lawsuit with prejudice.

Atlas Unitholder Litigation

Between October and December 2014, five public unitholders of APL (the "APL Plaintiffs") filed putative class action lawsuits against APL, ATLS, APL GP, its managers, Targa, the Partnership, the general partner and MLP Merger Sub (the "APL Lawsuit Defendants"). These lawsuits were styled (a) *Michael Evnin v. Atlas Pipeline Partners, L.P., et al*., in the Court of Common Pleas for Allegheny County, Pennsylvania; (b) *William B. Federman Family Wealth Preservation Trust v. Atlas Pipeline Partners, L.P., et al.*, in the District Court of Tulsa County, Oklahoma (the "Tulsa Lawsuit"); (c) *Greenthal Living Trust U/A 01/26/88 v. Atlas Pipeline Partners, L.P., et al*., in the Court of Common Pleas for Allegheny County, Pennsylvania; (d) *Mike Welborn v. Atlas Pipeline Partners, L.P., et al.*, in the Court of Common Pleas for Allegheny County, Pennsylvania; and (e) *Irving Feldbaum v. Atlas Pipeline Partners, L.P., et al.*, in the Court of Common Pleas for Allegheny County, Pennsylvania, though the Tulsa Lawsuit has been voluntarily dismissed. The *Evnin*, *Greenthal*, *Welborn and Feldbaum* lawsuits have been consolidated as *In re Atlas Pipeline Partners, L.P. Unitholder Litigation*, Case No. GD-14-019245, in the Court of Common Pleas for Allegheny County, Pennsylvania (the "Consolidated APL Lawsuit"). In October and November 2014, two public unitholders of ATLS (the "ATLS Plaintiffs" and, together with the APL Plaintiffs, the "Atlas Lawsuit Plaintiffs") filed putative class action lawsuits against ATLS, ATLS GP, its managers, Targa and GP Merger Sub (the "ATLS Lawsuit Defendants" and, together with the APL Lawsuit Defendants, the "Atlas Lawsuit Defendants"). These lawsuits were styled (a) *Rick Kane v. Atlas Energy, L.P., et al.*, in the Court of Common Pleas for Allegheny County, Pennsylvania and (b) *Jeffrey Ayers v. Atlas Energy, L.P., et al.*, in the Court of Common Pleas for Allegheny County, Pennsylvania (the "ATLS Lawsuits"). The ATLS Lawsuits have been consolidated as *In re Atlas Energy, L.P. Unitholder Litigation*, Case No. GD-14-019658, in the Court of Common Pleas for Allegheny County, Pennsylvania (the "Consolidated ATLS Lawsuit" and, together with the Consolidated APL Lawsuit, the "Consolidated Atlas Lawsuits"), though the *Kane* lawsuit has been voluntarily dismissed.

The Atlas Lawsuit Plaintiffs alleged a variety of causes of action challenging the Atlas mergers. Generally, the APL Plaintiffs alleged that (a) APL GP's managers have breached the covenant of good faith and/or their fiduciary duties and (b) Targa, the Partnership, the general partner, MLP Merger Sub, APL, ATLS and APL GP have aided and abetted in these alleged breaches of the covenant of good faith and/or fiduciary duties. The APL Plaintiffs further alleged that (a) the premium offered to APL's unitholders was inadequate, (b) APL agreed to contractual terms that would allegedly dissuade other potential acquirers from seeking to acquire APL, and (c) APL GP's managers favored their self-interests over the interests of APL's unitholders. The APL Plaintiffs in the Consolidated APL Lawsuit also alleged that the registration statement filed on November 19, 2014 failed, among other things, to disclose allegedly material details concerning (i) Stifel, Nicolaus & Company, Incorporated's analysis of the Atlas mergers; (ii) APL and the Partnership's financial projections; and (iii) the background of the Atlas mergers. Generally, the ATLS Plaintiffs alleged that (a) ATLS GP's directors have breached the covenant of good faith and/or their fiduciary duties and (b) Targa, GP Merger Sub, and ATLS have aided and abetted in these alleged breaches of the covenant of good faith and/or fiduciary duties. The ATLS Plaintiffs further alleged that (a) the premium offered to the ATLS unitholders was inadequate, (b) ATLS agreed to contractual terms that would allegedly dissuade other potential acquirers from seeking to acquire ATLS, (c) ATLS GP's directors favored their self-interests over the interests of the ATLS unitholders and (d) the registration statement failed to disclose allegedly material details concerning, among other things, (i) Wells Fargo Securities, LLC, Stifel, Nicolaus & Company, Incorporated, and Deutsche Bank Securities Inc.'s analyses of the Atlas mergers; (ii) the Partnership, Targa, APL, and ATLS' financial projections; and (iii) the background of the Atlas mergers.

Based on these allegations, the Atlas Lawsuit Plaintiffs sought to enjoin the Atlas Lawsuit Defendants from proceeding with or consummating the Atlas mergers unless and until APL and ATLS adopted and implemented processes to obtain the best possible terms for their respective unitholders. The Atlas Lawsuit Plaintiffs also sought rescission, damages, and attorneys' fees.

The parties to the Consolidated Atlas Lawsuits agreed to settle the Consolidated Atlas Lawsuits on February 9, 2015. In general, the settlements provide that in consideration for the dismissal of the Consolidated Atlas Lawsuits, ATLS and APL would provide supplemental disclosures regarding the Atlas mergers in a filing with the SEC on Form 8-K, which ATLS and APL did on February 11, 2015. The Atlas Lawsuit Defendants agreed to make such supplemental disclosures solely to avoid the uncertainty, risk, burden, and expense inherent in litigation and deny that any supplemental disclosure was or is required under any applicable rule, statute, regulation or law. On January 21, 2016, the Court granted final approval of the settlements in the Consolidated Atlas Lawsuits and dismissed the Consolidated Atlas Lawsuits with prejudice.

Environmental Proceedings

On August 22, 2014 and September 9, 2014, the Texas Commission on Environmental Quality ("TCEQ") issued Notices of Enforcement ("NOEs") to Targa Midstream Services LLC for alleged violations of air emissions regulations at the Mont Belvieu Fractionator relating to the operations of two regenerative thermal oxidizers during 2013 and 2014 and an unrelated discrete emissions event that occurred on May 29, 2014. On May 26, 2015, we signed an Agreed Order resolving all alleged violations stated in the NOEs. The Executive Director of the TCEQ signed the Agreed Order on September 11, 2015, and the TCEQ Commissioners approved the Agreed Order during their November 4, 2015 meeting. Pursuant to the Agreed Order, we (1) paid an administrative penalty in the amount of $115,644; and (2) paid $115,643 to fund certain supplemental environmental projects. Under the Agreed Order, we must comply with certain ordering provisions, including a requirement to install a flare gas recovery unit at the Mont Belvieu Fractionator within one year of the effective date of the Agreed Order.

On June 18, 2015, the New Mexico Environment Department's Air Quality Bureau issued a Notice of Violation to Targa Midstream Services LLC for alleged violations of air emissions regulations related to emissions events that occurred at the Monument Gas Plant between June 2014 and December 2014. The Monument Gas Plant is operated by us and owned by Versado Gas Processors, L.L.C., which is a joint venture in which we own a 63% interest. We are in discussions with the New Mexico Environment Department to resolve the alleged violations. We anticipate that this matter could result in a monetary sanction in excess of $100,000 but less than $300,000.

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

Note 18 – Income Tax

	2015	2014	2013
Provision for Income Taxes:			
Current expense	$ 0.8	$ 3.2	$ 2.0
Deferred expense (benefit)	(0.2)	1.6	0.9
Total income tax expense (benefit)	$ 0.6	$ 4.8	$ 2.9

The Partnership is subject to the Texas margin tax, consisting generally of a 0.75% tax on the amounts by which total revenues exceed cost of goods sold, as apportioned to Texas. As part of the APL merger in 2015, the Partnership acquired TPL Arkoma, Inc., a corporate subsidiary subject to federal and state income tax. The Partnership's corporate subsidiary accounts for income taxes under the asset and liability method and provides deferred income taxes for all significant temporary differences.

Our deferred income tax assets and liabilities at December 31, 2015 consist of differences related to the timing of recognition of certain types of costs as follows:

	Year Ended December 31,	
	2015	2014
Deferred tax assets:		
Net operating loss carryforwards	$ 19.8	$ -
Deferred tax liabilities:		
Property, plant, and equipment	(47.0)	(13.7)
Net deferred tax asset/(liability)	$ (27.2)	$ (13.7)

As of December 31, 2015, TPL Arkoma, Inc. had net operating loss carry forwards for federal income tax purposes of approximately $51.3 million, which expire at various dates from 2029 to 2035. Management of the General Partner believes it more likely than not that the deferred tax asset will be fully utilized.

Note 19 — Significant Risks and Uncertainties

Nature of 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.

The principal market risks are exposure to changes in commodity prices, as well as changes in interest rates.

Commodity Price Risk

A majority of the revenues from the gathering and processing business 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 and NGLs are subject to market fluctuations in response to changes in supply, demand, market uncertainty and a variety of additional factors beyond our control.

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 equity volumes and condensate equity volumes through 2018 by entering into financially settled derivative transactions. 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 of natural gas or NGLs and pays 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 natural gas and NGL equity volumes. Our commodity hedges may expose us to the risk of financial loss in certain circumstances.

Our net income and cash flows are subject to volatility stemming from changes in commodity prices and interest rates. To reduce the volatility of our cash flows, we have entered into derivative financial instruments related to a portion of our equity volumes to manage the purchase and sales prices of commodities. We also monitor NGL inventory levels with a view to mitigating losses related to downward price exposure.

Interest Rate Risk

We are exposed to changes in interest rates, primarily as a result of our variable rate borrowings under our TRP Revolver and Securitization Facility.

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, and would reduce our maximum loss due to counterparty credit risk by $7.6 million as of December 31, 2015. The range of losses attributable to our individual counterparties would be between $0.4 million and $38.9 million, depending on the counterparty in default.

Our 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 our 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.

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. The following table summarizes the activity affecting our allowance for bad debts:

	2015	2014	2013
Balance at beginning of year	$ -	$ 0.9	$ 0.7
Additions	0.1	-	0.2
Deductions		(0.9)	-
Balance at end of year	$ 0.1	$ -	$ 0.9

Significant Commercial Relationship

During the years ended December 31, 2015, 2014 and 2013, we did not have any commercial relationships that exceeded 10% of consolidated revenues.

During the year ended December 31, 2015, ONEOK Hydrocarbon L.P. accounted for 12% of our consolidated purchases with a supplier. During the years ended December 31, 2014 and 2013, we did not have any suppliers that exceeded 10% of our consolidated product purchases.

Casualty or Other Risks

Targa maintains coverage in various insurance programs on our behalf, which provides us with property damage, business interruption and other coverage which is customary for the nature and scope of our operations. The majority of the insurance costs described above is allocated to us by Targa through the Partnership Agreement described in Note 15 – Related Party Transactions.

Management believes that Targa has adequate insurance coverage, although insurance may not cover every type of interruption that might occur. As a result of insurance market conditions, premiums and deductibles may change overtime, and in some instances, certain insurance may become unavailable, or available for only reduced amounts of coverage. As a result, Targa may not be able to renew existing insurance policies or procure other desirable insurance on commercially reasonable terms, if at all.

If we were to incur a significant liability for which we were not fully insured, it could have a material impact on our consolidated financial position and results of operations. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur. Any event that interrupts the revenues generated by us, or which causes us to make significant expenditures not covered by insurance, could reduce our ability to meet our financial obligations. Furthermore, even when a business interruption event is covered, it could affect interperiod results as we would not recognize the contingent gain until realized in a period following the incident.

Note 20 — Other Operating (Income) Expense

	2015	2014	2013
Loss (gain) on sale or disposal of assets	$ (8.0)	$ (4.8)	$ 3.9
Casualty (gain) loss	(0.2)	0.1	4.3
Miscellaneous business tax	0.5	0.4	0.7
Other	0.6	1.3	0.7
	$ (7.1)	$ (3.0)	$ 9.6

Note 21 — Supplemental Cash Flow Information

	2015	2014	2013
Cash:			
Interest paid, net of capitalized interest (1)	$ 193.1	$ 131.0	$ 119.1
Income taxes paid, net of refunds	3.4	2.7	2.3
Non-cash investing activities:			
Deadstock commodity inventory transferred to property, plant and equipment	1.2	14.8	30.4
Impact of capital expenditure accruals on property, plant and equipment	43.8	19.0	(0.4)
Transfers from materials and supplies inventory to property, plant and equipment	3.7	4.6	20.5
Change in ARO liability and property, plant and equipment due to revised future ARO cash flow estimate	3.8	2.1	1.4
Property, plant and equipment in consideration of contract amendment (2)	22.6	-	-
Non-cash financing activities:			
Debt additions and retirements related to exchange of TRP 6⅝% Notes for APL 6⅝% Notes	342.1	-	-
Reductions in Owner's Equity related to accrued distributions on unvested equity awards under share compensation arrangements	1.6	1.4	1.7
Receivables from equity issuances	-	1.0	-
Accrued distributions of preferred unit	0.9	-	-
Non-cash balance sheet movements related to business acquisition: (See Note 4)			
Non-cash merger consideration - common units and replacement equity awards	$ 2,583.5	$ -	$ -
Special GP Interest	1,612.4	-	-
Current liabilities retained by Targa	(0.4)	-	-
Net non-cash balance sheet movements excluded from consolidated statements of cash flows	4,195.5	-	-
Net cash merger consideration included in investing activities	828.7	-	-
Total fair value of consideration transferred	$ 5,024.2	$ -	$ -

(1) Interest capitalized on major projects was $13.2 million, $16.1 million and $28.0 million for 2015, 2014 and 2013.

(2) We measured the estimated fair value of the assets transferred to us using significant other observable inputs representative of a Level 2 fair value measurement.

Note 22 — Compensation Plans

We recognize compensation expenses related to awards under our long-term incentive plan and expenses allocated to us under Targa's incentive plan. The components of each plan are shown as below:

Partnership Long-Term Incentive Plan
- Performance Units - Equity-settled
- Phantom Units - Equity -settled
  - Phantom Units
  - Replacement Phantom Units
- Director Grants

Allocated compensation cost related to:

TRC Long-Term Incentive Plan
- Cash-settled Performance Units

2010 TRC Stock Incentive Plan
- Restricted Stock Awards
- Restricted Stock Units - Equity- settled
  - Restricted Stock Units
  - Replacement Restricted Stock Units

Targa 401(k) Plan

Long-Term Incentive Plans

Performance Units

In 2007, both Targa and we adopted Long-Term Incentive Plans (each, an "LTIP") for employees, consultants, directors and non-employee directors of Targa and its affiliates who perform services for Targa or its affiliates. The performance units granted under these plans are linked to the performance of our common units. Targa's LTIP (the "TRC LTIP") provides for the grant of cash-settled performance units only, but our LTIP ("TRP LTIP") provides for, among other things, the grant of both cash-settled and equity-settled performance units. Performance unit awards granted under either LTIP may also include distribution equivalent rights ("DERs"). The TRP LTIPs are administered by the board of directors of our general partner, while the TRC LTIP is administered by the compensation committee (the "Committee") of the Targa Board of Directors. Total units authorized under the TRP LTIP are 1,680,000.

Each performance unit will entitle 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. Currently, the performance period for most awards is three years, except for certain awards granted in December 2013, which provide for two, three or four-year vesting periods. The grantee will receive 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. DERs are paid for both cash-settled and equity-settled performance units.

Compensation cost for equity-settled performance units is recognized as an expense over the performance period based on fair value at the grant date. Fair value is calculated using a simulated unit price that incorporates peer ranking. DERs associated with equity-settled performance units are accrued over the performance period as a reduction of owners' equity.

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 performance period we must record an accrued expense based on an estimate of that future pay-out. Targa and we use a Monte Carlo simulation model and historical volatility assumption to estimate accruals throughout the vesting period.

Equity-Settled Performance Units

The following table summarizes activities of our equity-settled performance units for the years ended December 31, 2015, 2014 and 2013.

	Number of units	Weighted Average Grant-Date Fair Value
Outstanding at December 31, 2012	307,620	$ 38.40
Granted	244,578	46.54
Outstanding at December 31, 2013	552,198	42.01
Granted	168,495	57.19
Vested	(137,170)	34.02
Forfeited	(6,120)	49.39
Outstanding at December 31, 2014	577,403	48.26
Granted	277,242	34.48
Vested	(178,900)	41.92
Outstanding at December 31, 2015	675,745	44.29

Equity – Settled Phantom units

In 2015, we granted phantom units under our LTIP to various employees of Targa. These phantom units are denominated with respect to our common units, but are not otherwise linked to the performance of our common units. Their vesting periods vary from one year to five years. The DERs of the phantom units are accumulated to be paid in cash at vesting date.

Phantom Units

In 2015 we issued 25,162 phantom units with the weighted average grant date fair value of $36.87. As of December 31, 2015, there are no forfeited phantom units.

Replacement Phantom Units

In connection with the APL merger, we awarded replacement phantom units in accordance with and as required by the Atlas Merger Agreements to those APL employees who became Targa employees upon closing of the acquisition. The vesting dates and terms remained unchanged from the original 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 DERs of the replacement phantom units are paid in cash within 60 days of the payment of distributions (see Note 4 - Business Acquisitions.)

The following table summarize the activities of the awards for the year ended 2015.

	Number of units	Weighted Average Grant-Date Fair Value
Outstanding at December 31, 2014	-	$ -
Granted	629,231	43.82
Vested	(224,021)	43.82
Forfeited	(49,852)	43.82
Outstanding at December 31, 2015	355,358	$ 43.82

Subsequent Event - On January 15, 2016, 3,405 replacement phantom units vested and we repurchased 1,289 units at $10.65 per unit to satisfy the employee's minimum statutory tax withholdings on the vested awards. The repurchased shares are recorded as treasury units at cost.

Director Grants

Starting in 2012, the common units granted to our non-management directors vest immediately at the grant date.

The following table summarizes the activities of the common unit-based awards granted to our Directors for the years ended December 31, 2015, 2014 and 2013 (in units and dollars):

	Number of units	Weighted Average Grant-Date Fair Value
Outstanding at December 31, 2012	4,500	$ 23.51
Granted	12,780	39.33
Vested	(17,280)	35.21
Outstanding at December 31, 2013	-	-
Granted	8,740	50.29
Vested	(8,740)	50.29
Outstanding at December 31, 2014	-	-
Granted	10,565	44.67
Vested	(10,565)	44.67
Outstanding at December 31, 2015	-	-

Subsequent Event - On January 19, 2016, the board of directors of our general partner made awards of 26,792 of our common units to our non-management directors. The awards vested immediately at the grant date.

TRC LTIP - Cash-settled Performance Units

The following table summarizes the cash-settled performance units for the year ended 2015 awarded under the TRC LTIP (in units and dollars):

	Program Year				
	2012 Awards	2013 Awards	2014 Awards	2015 Awards	Total
Units outstanding January 1, 2015	138,460	142,110	122,360	-	402,930
Granted	-	-	-	198,280	198,280
Vested and paid	(138,460)	-	-	-	(138,460)
Forfeited	-	(2,410)	(2,460)	(5,890)	(10,760)
Units outstanding December 31, 2015	-	139,700	119,900	192,390	451,990
Calculated fair market value as of December 31, 2015		$ 622,496	$ 359,684	$ 1,662,913	$ 2,645,093
Current liability		$ 511,247	$ -	$ -	$ 511,247
Long-term liability		-	172,926	229,460	402,386
Liability as of December 31, 2015		$ 511,247	$ 172,926	$ 229,460	$ 913,633
To be recognized in future periods		$ 111,249	$ 186,758	$ 1,433,453	$ 1,731,460
Vesting date		June 2016	June 2017	June 2018	

The remaining weighted average recognition period for the unrecognized compensation cost is approximately 2.3 years.

2010 TRC Stock Incentive Plan

In December 2010, Targa adopted the Targa Resources Corp. 2010 Stock Incentive Plan (“TRC Plan”) for employees, consultants and non-employee directors of the Company. The 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”).

Restricted Stock Awards – Total shares of Targa common stock authorized under this plan are 5,000,000. 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 following table summarizes the restricted stock awards in shares and in dollars for the years indicated:

	Number of shares	Weighted-average Grant-Date Fair Value
Outstanding at December 31, 2012	711,030	$ 25.95
Granted (1)	30,623	57.59
Forfeited	(2,740)	27.28
Vested (2)	(534,940)	22.00
Outstanding at December 31, 2013	203,973	41.05
Forfeited	(1,980)	42.82
Vested	(82,800)	33.37
Outstanding at December 31, 2014	119,193	46.35
Vested	(88,570)	42.46
Outstanding at December 31, 2015	30,623	57.59

(1) These awards will cliff vest at the end of three years.
(2) Awards vested in 2013 were 60% of the awards issued in conjunction with the Targa IPO, net of forfeitures. 40% of the awards vested prior to 2013.

Equity-Settled Restricted Stock Units

Restricted Stock Units ("RSUs") Awards – 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. The following table summarizes the regular RSUs Targa granted to the management of the general partner in shares and in dollars for the years indicated.

	Number of shares	Weighted-average Grant-Date Fair Value
Outstanding at December 31, 2012	-	$ -
Granted	55,790	69.90
Forfeited	(240)	67.07
Outstanding at December 31, 2013	55,550	69.92
Granted	54,357	112.89
Forfeited	(1,440)	75.81
Vested	(100)	67.07
Outstanding at December 31, 2014	108,367	91.41
Granted	140,477	83.54
Forfeited	(2,530)	86.73
Vested	(2,220)	81.56
Outstanding at December 31, 2015	244,094	87.02

RSU –Replacement Restricted Stock Units

In connection with the ATLS merger, we awarded RSUs in accordance with and as required by the Atlas Merger Agreements to those APL employees that who became Targa employees upon closing of the acquisition ("Replacement RSUs"). The vesting dates and terms remained unchanged from the existing ATLS awards, and will vest 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. The dividends of the replacement awards are paid in cash within 60 days of the payment of common stock dividends (see Note 4 – Business Acquisitions for details).

The following table summarizes the awards in shares and in dollars for the years indicated.

	Number of units	Weighted Average Grant-Date Fair Value
Outstanding at December 31, 2014	-	$ -
Granted	81,740	99.58
Vested	(41,539)	99.58
Forfeited	(1,556)	99.58
Outstanding at December 31, 2015	38,645	$ 99.58

Subsequent Events

In January 2016, the Committee made restricted stock units awards of 440,163 shares to executive management and employees under the TRC Plan for the 2016 compensation cycle that will cliff vest in three years from the grant date.

On January 15, 2016, 29,123 shares of the restricted stock units granted in January 2013 vested, and Targa repurchased 6,861 shares at $17.04 per share to satisfy the employee's minimum statutory tax withholdings on the vested awards. The repurchased shares are recorded by Targa in treasury stock at cost.

The following table summarizes the compensation expenses under the various compensation plans recognized for the years indicated:

	2015	2014	2013
TRP LTIP - Equity-Settled Performance Units	$ 9.5	$ 8.8	$ 5.5
TRP LTIP - Equity-Settled Phantom units - Replacement Phantom Units	6.4	-	-
TRP LTIP - Equity-Settled Phantom units - Phantom Units	0.2	-	-
Director Grants	0.5	0.4	0.5
Allocated from Targa:			
TRC LTIP - Cash-Settled Performance Units	(2.2)	11.0	21.9
2010 TRC Stock Incentive Plan - Restricted Stock	1.1	2.2	6.3
2010 TRC Stock Incentive Plan - Equity-Settled Restricted Stock Units: RSUs	5.4	2.5	0.4
2010 TRC Stock Incentive Plan - Equity-Settled Restricted Stock Units: Replacement RSUs	1.3	-	-

The table below summarizes the unrecognized compensation expenses and the approximate remaining weighted average vesting periods related to our various share-based compensation plans as of December 31, 2015:

	Unrecognized Compensation Expense	Weighted Average Remaining Vesting Period
	(In millions)	(In years)
TRP LTIP Equity-Settled Performance Units	$ 13.3	1.9
TRP LTIP Equity-Settled Phantom units - Replacement Phantom Units	5.8	1.3
TRP LTIP Equity-Settled Phantom units - Phantom Units	0.8	3.3
2010 TRC Stock Incentive Plan - Restricted Stock	0.0	0.1
2010 TRC Stock Incentive Plan - Equity-Settled Restricted Stock Units: RSUs	13.1	2.3
2010 TRC Stock Incentive Plan - Equity-Settled Restricted Stock Units: Replacement RSUs	1.5	1.4

The total fair value of share-based awards on the dates they vested are as follows:

	2015	2014	2013
TRP LTIP Equity-Settled Performance units	$ 7.9	$ 10.0	$ -
TRP LTIP Accrued DERs settled for Equity - Settled Performance units	1.7	1.6	-
TRP LTIP Replacement Phantom Units	8.8	-	-
Accrued DERs settled for Phantom units - TRP LTIP Replacement Phantom Units	1.1	-	-
Director Grants	0.5	0.4	0.7
TRC LTIP Cash-Settled performance units	7.8	14.7	25.2
2010 TRC Stock Incentive Plan - Restricted Stock (1)	7.3	7.1	42.2
Accrued dividends settled	0.2	0.5	2.4
2010 TRC Stock Incentive Plan - Equity-Settled Restricted Stock Units: Replacement RSUs	3.8	-	-

(1) Targa recognized $1.1 million, $1.0 million and $1.6 million in tax benefits associated with the vesting of the restricted stock for 2015, 2014 and 2013.

Targa 401(k) Plan

Targa has a 401(k) plan whereby it matches 100% of up to 5% of an employee's contribution (subject to certain limitations in the plan). Targa also contributes an amount equal to 3% of each employee's eligible compensation to the plan as a retirement contribution and may make additional contributions at its sole discretion. All Targa contributions are made 100% in cash. Targa made contributions to the 401(k) plan totaling $13.8 million, $10.5 million and $9.6 million during 2015, 2014 and 2013.

Note 23 — Segment Information

We aggregate our reporting segments into two divisions: (i) Gathering and Processing, consisting of two reportable segments – (a) Field Gathering and Processing and (b) Coastal Gathering and Processing; and (ii) Logistics and Marketing consisting of two reportable segments – (a) Logistics Assets and (b) Marketing and Distribution. The operating margin results of our commodity derivative activities are reported in Other.

Our Gathering and Processing division 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 Field 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; and the Williston Basin in North Dakota. The Coastal Gathering and Processing segment's assets are located in the onshore and near offshore regions of the Louisiana Gulf Coast and the Gulf of Mexico

Our Logistics and Marketing division is also referred to as our Downstream Business. Our Downstream Business 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, refined petroleum products and crude oil. It also includes certain natural gas supply and marketing activities in support of our other operations, including services to LPG exporters, as well as transporting natural gas and NGLs.

Our Logistics Assets segment is involved in transporting, storing, and fractionating mixed NGLs; storing, terminaling, and transporting finished NGLs, including services for the LPG export market; and storing and terminaling refined petroleum products. These assets are generally connected to and supplied in part by our Gathering and Processing segments and are predominantly located in Mont Belvieu and Galena Park, Texas and Lake Charles, Louisiana.

Our Marketing and Distribution segment covers activities required to distribute and market raw and finished NGLs and all natural gas marketing activities. It includes (1) marketing our own NGL production and purchasing NGL products for resale in selected United States markets; (2) providing LPG balancing services to refinery customers; (3) transporting, storing and selling propane and providing related propane logistics services to multi-state retailers, independent retailers and other end-users; (4) providing propane, butane and services to LPG exporters; and (5) marketing natural gas available to us from our Gathering and Processing division and the purchase and resale and other value added activities related to third-party natural gas in selected United States markets.

Other contains the results (including any hedge ineffectiveness) of commodity derivative activities included in operating margin and mark-to-market gain/losses related to derivative contracts that were not designated as cash-flow hedges. Eliminations of inter-segment transactions are reflected in the corporate and eliminations column.

We are reviewing our segment disclosures as a result of the merger and integration efforts related to the Atlas merger.

Our reportable segment information is shown in the following tables:

	Year Ended December 31, 2015						
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Total
Revenues							
Sales of commodities	$ 1,283.0	$ 202.4	$ 104.4	$ 3,791.4	$ 84.2	$ -	$ 5,465.4
Fees from midstream services	394.3	32.8	330.2	435.9	-	-	1,193.2
	1,677.3	235.2	434.6	4,227.3	84.2	-	6,658.6
Intersegment revenues							
Sales of commodities	894.0	232.3	9.1	290.6	-	(1,426.0)	-
Fees from midstream services	8.7	-	264.2	19.5	-	(292.4)	-
	902.7	232.3	273.3	310.1	-	(1,718.4)	-
Revenues	$ 2,580.0	$ 467.5	$ 707.9	$ 4,537.4	$ 84.2	$ (1,718.4)	$ 6,658.6
Operating margin	$ 484.8	$ 30.3	$ 439.5	$ 242.2	$ 84.2	$ -	$ 1,281.0
Other financial information:							
Total assets (1)	$ 9,892.3	$ 290.2	$ 1,912.2	$ 605.5	$ 127.1	$ 337.7	$ 13,165.0
Goodwill (2)	$ 417.0	$ -	$ -	$ -	$ -	$ -	$ 417.0
Capital expenditures	$ 481.5	$ 14.8	$ 257.6	$ 14.4	$ -	$ 8.9	$ 777.2
Business acquisition	$ 5,024.2	$ -	$ -	$ -	$ -	$ -	$ 5,024.2

(1) Corporate assets at the Segment level primarily include investments in unconsolidated subsidiaries and debt issuance cost associated with our debt obligations.

(2) Total assets include goodwill. Goodwill has been attributed to our Field Gathering and Processing segment – See Note 4 – Business Acquisitions.

	Year Ended December 31, 2014						
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Total
Revenues							
Sales of commodities	$ 197.4	$ 355.0	$ 99.1	$ 6,951.7	$ (8.0)	$ -	$ 7,595.2
Fees from midstream services	190.3	34.4	293.6	503.0	-	-	1,021.3
	387.7	389.4	392.7	7,454.7	(8.0)	-	8,616.5
Intersegment revenues							
Sales of commodities	1,491.2	577.6	4.4	486.7	-	(2,559.9)	-
Fees from midstream services	5.2	-	308.3	30.1	-	(343.6)	-
	1,496.4	577.6	312.7	516.8	-	(2,903.5)	-
Revenues	$ 1,884.1	$ 967.0	$ 705.4	$ 7,971.5	$ (8.0)	$ (2,903.5)	$ 8,616.5
Operating margin	$ 372.3	$ 77.6	$ 445.1	$ 249.6	$ (8.0)	$ -	$ 1,136.6
Other financial information:							
Total assets	$ 3,409.0	$ 367.2	$ 1,717.3	$ 708.5	$ 60.2	$ 115.0	$ 6,377.2
Capital expenditures	$ 423.1	$ 14.0	$ 274.4	$ 30.2	$ -	$ 6.1	$ 747.8

	Year Ended December 31, 2013						
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Total
Revenues							
Sales of commodities	$ 188.8	$ 305.0	$ 140.5	$ 5,072.4	$ 21.4	$ 0.1	$ 5,728.2
Fees from midstream services	113.9	33.6	216.0	223.3	-	(0.1)	586.7
	302.7	338.6	356.5	5,295.7	21.4	-	6,314.9
Intersegment revenues							
Sales of commodities	1,218.9	642.2	3.9	478.6	-	(2,343.6)	-
Fees from midstream services	3.4	1.0	176.5	29.8	-	(210.7)	-
	1,222.3	643.2	180.4	508.4	-	(2,554.3)	-
Revenues	$ 1,525.0	$ 981.8	$ 536.9	$ 5,804.1	$ 21.4	$ (2,554.3)	$ 6,314.9
Operating margin	$ 270.5	$ 85.4	$ 282.3	$ 141.9	$ 21.4	$ -	$ 801.5
Other financial information:							
Total assets	$ 3,200.7	$ 383.8	$ 1,503.6	$ 756.1	$ 5.1	$ 122.1	$ 5,971.4
Capital expenditures	$ 557.8	$ 20.6	$ 444.7	$ 6.3	$ -	$ 5.1	$ 1,034.5

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

	2015	2014	2013
Sales of commodities			
Natural gas	$ 1,594.5	$ 1,414.1	$ 1,225.0
NGL	3,558.7	5,960.1	4,224.0
Condensate	142.4	134.3	121.8
Petroleum products	101.6	96.3	136.0
Derivative activities	68.2	(9.6)	21.4
	5,465.4	7,595.2	5,728.2
Fees from midstream services			
Fractionating and treating	209.0	208.9	133.9
Storage, terminaling, transportation and export	506.2	548.1	280.3
Gathering and processing	393.7	196.9	114.1
Other	84.3	67.4	58.4
	1,193.2	1,021.3	586.7
Total revenues	$ 6,658.6	$ 8,616.5	$ 6,314.9

The following table shows a reconciliation of operating margin to net income (loss) for the periods presented:

	2015	2014	2013
Reconciliation of operating margin to net income (loss):			
Operating margin	$ 1,281.0	$ 1,136.6	$ 801.5
Depreciation and amortization expense	(677.1)	(346.5)	(271.6)
General and administrative expense	(153.6)	(139.8)	(143.1)
Provisional goodwill impairment	(290.0)	-	-
Interest expense, net	(207.8)	(143.8)	(131.0)
Other, net	(11.2)	3.4	5.7
Income tax expense	(0.6)	(4.8)	(2.9)
Net income (loss)	$ (59.3)	$ 505.1	$ 258.6

Note 24 — Selected Quarterly Financial Data (Unaudited)

Our results of operations by quarter for the years ended December 31, 2015 and 2014 were as follows:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter		Total
	(In millions, except per unit amounts)					
2015						
Revenues	$ 1,679.7	$ 1,699.4	$ 1,632.1	$ 1,647.4		$ 6,658.6
Gross margin	411.4	462.3	459.7	452.2		1,785.6
Operating income (loss)	141.0	114.8	117.3	(205.7)	(1)(2)	167.4
Net income (loss)	77.8	53.3	53.3	(243.7)		(59.3)
Net income attributable to limited partners (loss)	30.3	1.2	3.6	(232.6)		(197.5)
Net income (loss) per limited partner unit						
- basic	$ 0.21	$ 0.01	$ 0.02	$ (1.26)		$ (1.15)
- diluted	$ 0.21	$ 0.01	$ 0.02	$ (1.26)		$ (1.15)
2014						
Revenues	$ 2,294.7	$ 2,000.6	$ 2,288.3	$ 2,032.9		$ 8,616.5
Gross margin	379.6	384.0	407.8	398.2		1,569.6
Operating income	160.6	152.9	171.4	168.4	(1)	653.3
Net income	131.3	120.9	138.2	114.7		505.1
Net income attributable to limited partners	88.6	73.0	89.7	67.7		319.0
Net income per limited partner unit						
- basic	$ 0.79	$ 0.64	$ 0.78	$ 0.58		$ 2.78
- diluted	$ 0.78	$ 0.64	$ 0.78	$ 0.58		$ 2.77

(1) Included $32.6 million in the fourth quarter of 2015 and $3.2 million in the fourth quarter of 2014 losses due to the impairments. See Note 6 – Property, Plant and Equipment and Intangible Assets.
(2) Included a provisional goodwill impairment of $290.0 million in the fourth quarter of 2015. See Note 4 –Business Acquisitions.

Exhibit 21.1

Targa Resources Partners LP Subsidiary List

Entity Name	Jurisdiction of Formation
Carnero Gathering, LLC	Delaware
Carnero Processing, LLC	Delaware
Cedar Bayou Fractionators, L.P.	Delaware
Centrahoma Processing LLC	Delaware
DEVCO Holdings LLC	Delaware
Downstream Energy Ventures Co., L.L.C.	Delaware
Gulf Coast Fractionators	Texas
NOARK Energy Services, L.L.C.	Oklahoma
Pecos Pipeline LLC	Delaware
Salta Properties LLC	Delaware
Setting Sun Pipeline Corporation	Delaware
Slider WestOk Gathering, LLC	Delaware
T2 Eagle Ford Gathering Company LLC	Delaware
T2 EF Cogeneration Holdings LLC	Delaware
T2 EF Cogeneration LLC	Texas
T2 Gas Utility LLC	Texas
T2 LaSalle Gas Utility LLC	Texas
T2 LaSalle Gathering Company LLC	Delaware
Targa Acquisition LLC	Delaware
Targa Badlands LLC	Delaware
Targa Canada Liquids Inc.	British Columbia
Targa Capital LLC	Delaware
Targa Chaney Dell LLC	Delaware
Targa Cogen LLC	Delaware
Targa Downstream LLC	Delaware
Targa Gas Marketing LLC	Delaware
Targa Gas Pipeline LLC	Delaware
Targa Gas Processing LLC	Delaware
Targa Intrastate Pipeline LLC	Delaware
Targa Liquids Marketing and Trade LLC	Delaware
Targa Louisiana Intrastate LLC	Delaware
Targa Midkiff LLC	Delaware
Targa Midstream Services LLC	Delaware
Targa MLP Capital LLC	Delaware
Targa NGL Pipeline Company LLC	Delaware
Targa Pipeline Escrow LLC	Delaware
Targa Pipeline Finance Corporation	Delaware
Targa Pipeline Mid-Continent Holdings LLC	Delaware
Targa Pipeline Mid-Continent LLC	Delaware
Targa Pipeline Mid-Continent WestOk LLC	Delaware
Targa Pipeline Mid-Continent WestTex LLC	Delaware
Targa Pipeline Operating Partnership LP	Delaware
Targa Pipeline Partners GP LLC	Delaware
Targa Pipeline Partners LP	Delaware
Targa Receivables LLC	Delaware
Targa Resources Operating GP LLC	Delaware

Entity Name	Jurisdiction of Formation
Targa Resources Operating LLC	Delaware
Targa Resources Partners Finance Corporation	Delaware
Targa Sound Terminal LLC	Delaware
Targa SouthTex Midstream Company LP	Texas
Targa Terminals LLC	Delaware
Targa Transport LLC	Delaware
Tesuque Pipeline, LLC	Delaware
TPL Arkoma Holdings LLC	Delaware
TPL Arkoma Inc.	Delaware
TPL Arkoma Midstream LLC	Delaware
TPL Barnett LLC	Delaware
TPL Gas Treating LLC	Delaware
TPL Laurel Mountain LLC	Delaware
TPL SouthTex Gas Utility Company LP	Texas
TPL SouthTex Midstream Holding Company LP	Texas
TPL SouthTex Midstream LLC	Delaware
TPL SouthTex Pipeline Company LLC	Texas
TPL SouthTex Processing Company LP	Texas
TPL SouthTex Transmission Company LP	Texas
Velma Gas Processing Company, LLC	Delaware
Velma Intrastate Gas Transmission Company, LLC	Delaware
Venice Energy Services Company, L.L.C.	Delaware
Venice Gathering System, L.L.C.	Delaware
Versado Gas Processors, L.L.C.	Delaware
Warren Petroleum Company LLC	Delaware

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-8 (No.333-202502) and Form S-8 (No. 333-149200) of Targa Resources Partners LP of our report dated February 29, 2016 relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP
Houston, Texas
February 29, 2016

Exhibit 31.1

CERTIFICATION
PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Joe Bob Perkins, certify that:

1. I have reviewed this Annual Report on Form 10-K of Targa Resources Partners LP (the “registrant”);

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

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

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

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

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

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

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

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

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

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

Date: February 29, 2016

By: /s/ Joe Bob Perkins
Name: Joe Bob Perkins
Title: Chief Executive Officer of Targa Resources GP LLC,
the general partner of Targa Resources Partners LP
(Principal Executive Officer)

Exhibit 31.2

CERTIFICATION
PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Matthew J. Meloy, certify that:

1. I have reviewed this Annual Report on Form 10-K of Targa Resources Partners LP (the “registrant”);

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

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

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

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

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

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

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

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

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

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

Date: February 29, 2016

By: /s/ Matthew J. Meloy
Name: Matthew J. Meloy
Title: Executive Vice President and Chief Financial Officer
of Targa Resources GP LLC, the general partner of Targa Resources Partners LP
(Principal Financial Officer)

Exhibit 32.1

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

In connection with the Annual Report on Form 10-K of Targa Resources Partners LP (the “Partnership”) for the year ended 2015 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), Joe Bob Perkins, as Chief Executive Officer of Targa Resources GP LLC, the general partner of the Partnership, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

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

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

By: /s/ Joe Bob Perkins
Name: Joe Bob Perkins
Title: Chief Executive Officer of Targa Resources GP LLC,
the general partner of Targa Resources Partners LP

Date: February 29, 2016

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

Exhibit 32.2

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

In connection with the Annual Report on Form 10-K of Targa Resources Partners LP (the “Partnership”) for the year ended 2015 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), Matthew J. Meloy, as Chief Financial Officer of Targa Resources GP LLC, the general partner of the Partnership, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

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

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

By: /s/ Matthew J. Meloy
Name: Matthew J. Meloy
Title: Executive Vice President and Chief Financial Officer
of Targa Resources GP LLC, the general partner of
Targa Resources Partners LP

Date: February 29, 2016

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