

Targa Resources Corp.  
Form 10-K  
February 17, 2015

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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, 2014

or

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

For the transition period from \_\_\_\_\_ to \_\_\_\_\_

Commission File Number: 001-34991

TARGA RESOURCES CORP.  
(Exact name of registrant as specified in its charter)

Delaware 20-3701075  
(State or other jurisdiction of incorporation or organization) (I.R.S. Employer Identification No.)

1000 Louisiana St, Suite 4300, Houston, Texas 77002  
(Address of principal executive offices) (Zip Code)

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

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

Title of each class Name of each exchange on which registered  
Common Stock New York Stock Exchange  
Securities registered pursuant to section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.  
Yes R 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 R

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 R No

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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  Smaller reporting company

(Do not check if a 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 stock held by non-affiliates of the registrant was approximately \$5,888.0 million on June 30, 2014, based on \$139.57 per share, the closing price of the common stock as reported on the New York Stock Exchange (NYSE) on such date.

As of February 6, 2015, there were 42,143,395 shares of the registrant's common stock, \$0.001 par value, outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None

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TABLE OF CONTENTS

PART I

<u>Item 1. Business.</u>	4
<u>Item 1A. Risk Factors.</u>	34
<u>Item 1B. Unresolved Staff Comments.</u>	57
<u>Item 2. Properties.</u>	57
<u>Item 3. Legal Proceedings.</u>	57
<u>Item 4. Mine Safety Disclosures.</u>	59

PART II

<u>Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.</u>	59
<u>Item 6. Selected Financial Data.</u>	63
<u>Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.</u>	64
<u>Item 7A. Quantitative and Qualitative Disclosures About Market Risk.</u>	104
<u>Item 8. Financial Statements and Supplementary Data.</u>	108
<u>Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure.</u>	108
<u>Item 9A. Controls and Procedures.</u>	108
<u>Item 9B. Other Information.</u>	108

PART III

<u>Item 10. Directors, Executive Officers and Corporate Governance.</u>	109
<u>Item 11. Executive Compensation.</u>	115
<u>Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.</u>	143
<u>Item 13. Certain Relationships and Related Transactions, and Director Independence.</u>	144
<u>Item 14. Principal Accounting Fees and Services.</u>	149

PART IV

<u>Item 15. Exhibits, Financial Statement Schedules.</u>	150
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Table of Contents

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Targa Resources Corp.'s (together with its subsidiaries, other than Targa Resources Partners LP ("the Partnership"), "we," "us," "Targa," "TRC," or the "Company") reports, filings and other public announcements may from time to time contain statements that do not directly or exclusively relate to historical facts. Such statements are "forward-looking statements." You can typically identify forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, by the use of forward-looking statements, such as "may," "could," "project," "believe," "anticipate," "expect," "estimate," "potential," "plan" 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 risks set forth in "Item 1A. Risk Factors." in this Annual Report on Form 10-K ("Annual Report") as well as the following risks and uncertainties:

- the Partnership's and our ability to access the debt and equity 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 the Partnership's transactions;
- the Partnership's success in risk management activities, including the use of derivative instruments to hedge commodity risks;
- the level of creditworthiness of counterparties to various transactions with the Partnership;
- changes in laws and regulations, particularly with regard to taxes, safety and protection of the environment;
- the timing and extent of changes in natural gas, natural gas liquids ("NGL"), crude oil and other commodity prices, interest rates and demand for the Partnership's services;
- weather and other natural phenomena;
- industry changes, including the impact of consolidations and changes in competition;
- the Partnership's ability to obtain necessary licenses, permits and other approvals;
- the level and success of crude oil and natural gas drilling around the Partnership's assets, its success in connecting natural gas supplies to its gathering and processing systems, oil supplies to its gathering systems and NGL supplies to its logistics and marketing facilities and the Partnership's success in connecting its facilities to transportation and markets;
- the Partnership's and our ability to grow through acquisitions or internal growth projects and the successful integration and future performance of such assets;

the Partnership's ability to complete the proposed merger (the "APL Merger") with Atlas Pipeline Partners, L.P., a Delaware limited partnership ("APL"), and our ability to complete the proposed merger (the "ATLS Merger" and, together with the APL Merger, the "Atlas Mergers") with Atlas Energy, L.P., a Delaware limited partnership ("ATLS," and, together with APL, "Atlas"), upon which the closing of the APL Merger is conditioned, on the anticipated terms and time frame;

risks relating to obtaining the approval of our stock issuance in connection with the ATLS Merger by our stockholders and the approval of the Atlas Mergers by the unitholders of ATLS and APL, as applicable, and to satisfying the other conditions to the consummation of the Atlas Mergers;

Table of Contents

the potential impact of the announcement or consummation of the Atlas Mergers on our relationships, including with employees, suppliers, customers, competitors and credit rating agencies;

the Partnership’s and our ability to integrate with APL and ATLS successfully after consummation of the Atlas Mergers and to achieve anticipated benefits from the proposed transaction;

risks relating to any unforeseen liabilities of APL or ATLS;

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 Offer 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



Table of Contents

PART I

Item 1. Business.

Overview

Targa Resources Corp. (NYSE: TRGP) is a publicly traded Delaware corporation formed in October 2005. We do not directly own any operating assets; our main source of future revenue therefore is from general and limited partner interests, including incentive distribution rights (“IDRs”), in the Partnership, a publicly traded Delaware limited partnership (NYSE: NGLS) that is a leading provider of midstream natural gas and natural gas liquid services in the United States. The Partnership is engaged in the business of gathering, compressing, treating, processing and selling natural gas and storing, fractionating, treating, transporting, terminaling and selling NGLs, NGL products, and gathering, storing and terminaling crude oil and refined petroleum products.

Financial Presentation

One of our indirect subsidiaries is the sole general partner of the Partnership. Because we control the general partner, under generally accepted accounting principles we must reflect our ownership interest in the Partnership on a consolidated basis. Accordingly, the Partnership’s financial results are included in our consolidated financial statements even though the distribution or transfer of Partnership assets are limited by the terms of the partnership agreement, as well as restrictive covenants in the Partnership’s lending agreements. The limited partner interests in the Partnership not owned by us are reflected in our results of operations as net income attributable to noncontrolling interests. Throughout this Annual Report, we make a distinction where relevant between financial results and disclosures applicable to the Partnership versus those applicable to us as a standalone parent including our non-Partnership subsidiaries (“Non-Partnership”). In addition, we provide condensed Parent only financial statements as required by the SEC.

The Partnership files its own separate Annual Report. The financial results presented in our consolidated financial statements will differ from the financial statements of the Partnership primarily due to the effects of:

- our separate debt obligations;
- federal income taxes;
- certain retained general and administrative costs applicable to us as a public company;
- certain administrative assets and liabilities incumbent as a provider of operational and support services to the Partnership;
- certain non-operating assets and liabilities that we retained;
- Partnership distributions and earnings allocable to third-party common unitholders which are included in non-controlling interest in our statements; and

Partnership distributions applicable to our General Partner interest, IDR’s and investment in Partnership common units. While these are eliminated when preparing our consolidated financial statements, they nonetheless are the primary source of cash flow that supports the payment of dividends to our stockholders.

Overview of the Business of Targa Resources Corp.

Our primary business objective is to increase our cash available for dividends to our stockholders by assisting the Partnership in executing its business strategy. We may potentially facilitate the Partnership's growth through various forms of financial support, including, but not limited to, modifying the Partnership's IDRs, exercising the Partnership's IDR reset provision contained in its partnership agreement, making loans, making capital contributions in exchange for yielding or non-yielding equity interests or providing other financial support to the Partnership to support its ability to make distributions. In addition, we may potentially acquire assets that could be candidates for acquisition by the Partnership, potentially after operational or commercial improvement or further development.

Table of Contents

At February 6, 2015, our interests in the Partnership consist of the following:

- a 2% general partner interest, which we hold through our 100% ownership interest in the general partner;
- all of the outstanding IDRs; and

12,945,659 of the 118,880,758 outstanding common units of the Partnership, representing a 10.9% limited partnership interest.

Our cash flows are generated from the cash distributions we receive from the Partnership. The Partnership is required to distribute all available cash at the end of each quarter after establishing reserves to provide for the proper conduct of its business or to provide for future distributions. Our ownership of the general partner interest entitles us to receive 2% of all cash distributed in a quarter.

Our ownership of the IDRs of the Partnership entitles us to receive:

13% of all cash distributed in a quarter after \$0.3881 has been distributed in respect of each common unit of the Partnership for that quarter;

23% of all cash distributed in a quarter after \$0.4219 has been distributed in respect of each common unit of the Partnership for that quarter; and

48% of all cash distributed in a quarter after \$0.50625 has been distributed in respect of each common unit of the Partnership for that quarter.

Our ownership of Partnership common units entitles us to receive our percentage of the quarterly declared distributions that are paid to common unitholders.

The Partnership Agreement between the Partnership and us governs our relationship regarding certain reimbursement and indemnification matters. So long as our only cash generating assets are our interests in the Partnership, we will continue to allocate to the Partnership substantially all of our general and administrative costs other than our direct costs of being a reporting company. See “Item 13. Certain Relationships and Related Transactions, and Director Independence.”

We employ approximately 1,350 people. See “Employees.” The Partnership does not have any employees to carry out its operations.

Overview of the Business of the Partnership

Targa Resources Partners LP (NYSE:NGLS) is a publicly traded Delaware limited partnership formed in October 2006 by us to own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets. The Partnership 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.

The Partnership is engaged in the business of:

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

· gathering, storing and terminaling crude  
oil; and

· storing, terminaling and selling refined petroleum products.

5

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## Table of Contents

To provide these services, the Partnership operates 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 the Partnership’s Downstream Business), consisting of two reportable segments—(a) Logistics Assets and (b) Marketing and Distribution. For a detailed description of these businesses, please see “—The Partnership’s Business Operations.”

The Partnership’s midstream natural gas and NGL services footprint was initially established through several acquisitions from us, totaling \$3.1 billion, that occurred from 2007 through 2010. In these transactions the Partnership acquired (1) natural gas gathering, processing and treating assets in North Texas, West Texas, New Mexico and the Louisiana Gulf Coast and (2) 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 drop down acquisitions from us in 2010, the Partnership has grown substantially, with large increases in a number of metrics as of year-end 2014, including its total assets (108%), adjusted Earnings before interest, taxes, depreciation and amortization (“EBITDA”) (161%), distributable cash flow (188%) and distributions per unit to its common unitholders (51%). The expansion of the Partnership’s business has been fueled by a combination of major organic growth investments in the Partnership’s businesses and acquisitions.

### Organic Growth Projects

The Partnership continues to invest significant capital to expand through organic growth projects. The Partnership has invested approximately \$2.6 billion in growth capital expenditures since 2007, including approximately \$0.7 billion in 2014. These expansion investments were distributed across its businesses, with 43% related to Logistics and Marketing and 57% to Gathering and Processing. The Partnership will continue to invest in both large and small organic growth projects in 2015, though the Partnership expects that the amount of capital expenditures will vary depending on the level of drilling activity around its areas of operation. The Partnership currently estimates that it will have \$490 to \$675 million of estimated growth capital expenditures for announced projects in 2015.

### 2014 Developments

#### Logistics and Marketing Segment Expansion

#### International Exports

In September 2013, the Partnership commissioned Phase I of the international export expansion project, which includes facilities at both Mont Belvieu and the Galena Park Marine Terminal near Houston, Texas. Phase I of this project expanded the Partnership’s export capability to approximately 3.5 to 4 MMBbl per month of propane and/or butane. Included in the Partnership’s Phase I of the expansion is the capability to export international grade low ethane propane. With the completion of Phase I, the Partnership’s capabilities expanded to include loading very large gas carrier (“VLGC”) vessels in addition to the small and medium-sized vessels that the Partnership previously loaded for export.

The Partnership completed Phase II of this project in stages during 2014, which added incremental capacity and operational efficiencies including refrigeration, another dock, a new pipeline between Mont Belvieu and Galena Park and a de-ethanizer that increased the effective capacity to 7.0 MMBbl per month. The total cost of the Partnership’s international export expansion project was approximately \$480 million.

#### Condensate Splitter or Alternate Project

On March 31, 2014, the Partnership announced the approval to construct a condensate splitter at the Partnership's Channelview Terminal on the Houston Ship Channel. The condensate splitter was supported by a long-term fee-based arrangement with Noble Americas Corp., a subsidiary of Noble Group Ltd. The initial project would have the capability to split approximately 35 MBbl/d of condensate into its various components, including naphtha, kerosene, gas oil, jet fuel and liquefied petroleum gas, and will provide segregated storage for the condensate and components.

## Table of Contents

Effective December 31, 2014, the Partnership and Noble agreed to modify the existing arrangements to build (i) a new terminal with significant storage capacity at the Patriot facility on the Houston Ship Channel; or (ii) a condensate splitter at Channelview with modified timing; or (iii) potentially both projects. The Partnership and Noble are evaluating these alternatives including final capabilities, capacities and capital costs. The modifications to the previous arrangements provide for the Partnership to receive an upfront payment and an enhanced economic benefit over time. The projects are now expected to be completed by the end of 2016 or 2017, depending on final project scope and on permitting.

### Cedar Bayou Fractionator Train 5

In July 2014, the Partnership approved construction of a 100 MBbl/d fractionator at its 88%-owned Cedar Bayou Fractionator (“CBF”) in Mont Belvieu, Texas. The 100 MBbl/d expansion will be fully integrated with the Partnership’s 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. All environmental and internal approvals required to commence construction of the expansion are in place, construction is underway and the Partnership expects completion of construction in mid-2016. Construction of the expansion will proceed without disruption to existing operations, and the Partnership estimates that total capital expenditures for the expansion and the related infrastructure enhancements at Mont Belvieu should approximate \$385 million.

### Field Gathering and Processing Segment

#### Badlands

During 2013, the Partnership invested approximately \$250 million to expand its gathering and processing business in the Williston Basin, North Dakota assets. The Partnership increased its crude gathering and natural gas gathering operations substantially with the addition of pipelines and associated facilities and added an additional 20 MMcf/d natural gas processing plant. During 2014, the Partnership invested approximately \$165 million for further expansion of this business, including an additional cryogenic processing plant that will commence operations during the first quarter of 2015 and will bring the total processing capacity to approximately 90 MMcf/d. During 2015, the Partnership anticipates that it will invest approximately \$125 to \$250 million for further expansion of this business.

#### North Texas, SAOU, and Sand Hills

In May 2014, the Partnership commenced commercial operations of the 200 MMcf/d cryogenic Longhorn processing plant in North Texas, and in June 2014, the Partnership commenced commercial operations of the 200 MMcf/d cryogenic High Plains processing plant in the Permian Basin. The Partnership also completed a 32 mile pipeline to connect the Sand Hills system to the High Plains plant. We believe these projects will enable the Partnership to meet increasing production from continued producer activity in the Barnett Shale and the eastern side of the Permian Basin.

#### Growth Investments in the Permian and Williston Basins

In October 2014, the Partnership announced a new 300 MMcf/d cryogenic processing plant with an anticipated start-up in early 2016. This plant will also include related gathering and compression infrastructure in the Delaware Basin, west of the Partnership’s existing Sand Hills gas processing plant.

In October 2014, the Partnership announced a 200 MMcf/d cryogenic processing plant to be located in McKenzie County, North Dakota with an anticipated start-up in 2016.

Given the significant decrease in commodity prices and expected reductions in producer activity since those announcements, the Partnership is reevaluating the capacity and expected timing for both of these projects.

In the current market environment, the Partnership is actively monitoring producer responses to changes in the commodity price environment and will continue to adjust our growth capital expenditure programs to meet expected producer requirements.

7

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Table of Contents

Pending Atlas Mergers

On October 13, 2014, we and the Partnership announced two proposed merger transactions which would result in the Partnership's acquisition of Atlas Pipeline Partners, L.P (APL), a Delaware limited partnership, and Targa's acquisition of Atlas Energy, L.P. (ATLS), a Delaware limited partnership, which owns the APL general partner (the "Transactions"). Upon consummation of these mergers, we would relinquish all APL ownership interests and merge the APL general partner into the Partnership. Each of the Transactions is contingent on one another, and the Transactions are expected to close concurrently on February 28, 2015, subject to the approval of our stock issuance in connection with the ATLS Merger by our stockholders and the approval of the Atlas Mergers by unitholders of ATLS and APL, as applicable, and other customary closing conditions.

APL 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.

Strategic Rationale:

We believe that the combination of the Partnership and APL creates a premier midstream franchise with increased scale, geographic diversity, and creates one of the larger diversified Master Limited Partnerships ("MLPs") on an enterprise value basis. Highlights include the following:

- Adds APL's Woodford/SCOOP, Mississippi Lime, Eagle Ford and additional Permian assets to the Partnership's existing Permian, Bakken, Barnett, and Louisiana Gulf Coast gathering and processing operations.

- Combined position across the Permian Basin enhances service capabilities in one of the most active producing basins in North America, with a combined 1,439 MMcf/d of processing capacity and 10,300 miles of pipelines.

  - Strong growth outlook with significant announced combined organic growth capital expenditures.

- Growing NGL production from gathering and processing business supports the Partnership's leading NGL fractionation and export position.

- Enhances credit profile and results in an estimated 60-70% pro forma fee-based margin.

  - Underlying growth in the businesses drives incrementally higher distribution and dividend growth.

For more information regarding the transactions, see "Management's Discussion and Analysis on Financial Information and Results of Operations" and Note 4 to the "Consolidated Financial Statements" beginning on page F-1 of this Annual Report.

Growth Drivers

We believe that the Partnership's near-term growth will be driven by significant organic growth investments to meet supply and demand fundamentals for its existing businesses and its combined businesses following closing of the Atlas Mergers. The Partnership believes its assets are not easily duplicated and are located in active producing areas and near key markets and logistics centers. Over the longer term, the Partnership expects its growth will continue to be driven by 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. The Partnership expects that third-party acquisitions will also

continue to be a focus of its growth strategy.

Strong supply and demand fundamentals for the Partnership's existing businesses

We believe that, despite recent declines, with current commodity price levels for crude oil, condensate and NGLs, producers in and around the Partnership's crude oil gathering and natural gas gathering and gas processing areas of operation will continue drilling programs in regions rich in these forms of hydrocarbons, where economics are attractive to producers. Liquids rich gas is prevalent from oil wells in the Wolfberry, Cline and Canyon Sands plays, which are accessible by the SAOU processing business in the Permian Basin; from the oil wells in the Wolfberry and Bone Springs plays and re-development of the Central Basin, which are accessible by the Sand Hills system and the Versado system; from "oilier" portions of the Barnett Shale natural gas play, especially portions of Montague, Cooke, Clay and Wise counties, which are accessible by the North Texas System and from oil wells in the Bakken and Three Forks plays, which are accessible by its Badlands business in North Dakota.

8

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## Table of Contents

The impact of producer activity and resulting NGL supplies from areas rich in crude oil, condensate and NGLs continue to generate demand for the Partnership's fractionation services at the Mont Belvieu market hub and for LPG export services at the Partnership's Galena Park Marine Terminal on the Houston Ship Channel. Since 2010, in response to increasing demand, the Partnership has added 178 MBbl/d of additional fractionation capacity with the additions of CBF Trains 3 and 4, and has started construction of CBF Train 5 which is expected to add an additional 100 MBbl/d of fractionation capacity starting in mid-2016. The Partnership also funded its share of the NGL fractionation expansion at Gulf Coast Fractionators ("GCF"). The strength of demand continues to benefit fractionation service providers in the form of long-term, "take-or-pay" contracts for new and existing fractionation capacity. The Partnership believes that the higher volumes of fractionated NGLs will also result in increased demand for other related fee-based services provided by the Partnership's Downstream Business. Continued demand for fractionation capacity is expected to lead to other growth opportunities.

As domestic producers have focused their drilling in crude oil and liquids-rich areas, new gas processing facilities are being built to accommodate liquids-rich gas, which results in an increasing supply of NGLs. As drilling in these areas continues, demand for NGLs requiring transportation and fractionation to market hubs is expected to continue. As the supply of NGLs increase, the Partnership's integrated Mont Belvieu and Galena Park Terminal assets allow the Partnership to provide the raw product, fractionation, storage, interconnected terminaling, refrigeration and ship loading capabilities to support exports by third party customers.

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

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

Bakken Shale / Three Forks opportunities

The production from the Bakken Shale and Three Forks plays has made the Williston Basin one of the fastest growing crude oil basins in the world. As producers increased their knowledge of the basin, drilling efficiencies and completion techniques have improved and production has increased significantly. Currently, much of the current oil production is transported by truck from wells to terminals to be loaded onto rail cars or injected into pipelines. In addition, much of the current gas production is being flared. The Partnership believes that competition with trucking and regulations enacted in 2014 by the state of North Dakota mandating that producers have a plan to capture their natural gas production and reduce flaring provide opportunities to grow volumes and expand its crude gathering and natural gas gathering and processing infrastructure volumes; and that its position in the Williston Basin should allow us to compete for growth opportunities.

Third party acquisitions

While the Partnership's growth through 2010 was primarily driven by the implementation of a focused drop down strategy, the Partnership and Targa also have a record of completing third party acquisitions. Since its formation, its strategy included approximately \$6.2 billion in acquisitions and growth capital expenditures of which approximately \$1.2 billion was for acquisitions from third-parties (excluding the Atlas Mergers). The Partnership expects that third-party acquisitions will continue to be a focus of its growth strategy.

Competitive Strengths and Strategies

We believe that the Partnership is well positioned to execute its business strategies due to the following competitive strengths:

9

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## Table of Contents

### Strategically located gathering and processing asset base

The Partnership's gathering and processing businesses are predominantly located in active and growth-oriented oil and gas producing basins. Activity in the shale resource plays underlying its gathering assets is driven by oil, condensate and NGL production and generally favorable economics. Increased drilling and production activities in these areas would likely increase the volumes of natural gas and crude oil available to its gathering and processing systems.

### Leading fractionation, LPG export and NGL infrastructure position

The Partnership is one of the largest fractionators of NGLs in the Gulf Coast. Its primary fractionation assets are located in Mont Belvieu, Texas and to a lesser extent Lake Charles, Louisiana, which are key market centers for NGLs. Most of the Partnership's fractionation assets are located at Mont Belvieu, the major U.S. hub of NGL infrastructure, which includes a number of mixed NGL ("mixed NGLs" or "Y-grade") supply pipelines, storage, takeaway pipelines and other transportation infrastructure. Its Logistics assets, including fractionation facilities, storage wells, its 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 the Partnership has sufficient additional capability to expand their capacity. The Partnership has extensive experience in operating these assets and developing, permitting and constructing new midstream assets.

### Comprehensive package of midstream services

The Partnership provides 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 that the Partnership's ability to provide these integrated services provides an advantage in competing for new supplies because the Partnership 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, the Partnership believes the barriers to enter the midstream sector on a scale similar to the Partnership's are reasonably high due to the high cost of replicating 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

The Partnership's 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 its operations resulting in lower costs and minimal downtime. The Partnership has established a reputation in the midstream industry as a reliable and cost-effective supplier of services to its customers and has a track record of safe, efficient, and reliable operation of its facilities. The Partnership intends to continue to pursue new contracts, cost efficiencies and operating improvements of its 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. The Partnership will also continue to optimize existing plant assets to improve and maximize capacity and throughput.

In addition to routine annual maintenance expenses, the Partnership's maintenance capital expenditures have averaged approximately \$75 million per year over the last four years. We believe that the Partnership's assets are well-maintained and anticipate that a similar level of maintenance capital expenditures will be sufficient for the

Partnership to continue to operate its existing assets in a prudent and cost-effective manner.

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

The Partnership maintains gas gathering and processing positions in strategic oil and gas producing areas across multiple basins and provides services under attractive contract terms to a diverse mix of customers across its areas of operation. Consequently, the Partnership is not dependent on any one oil and gas basin or customer. The Partnership's Logistics and Marketing assets are typically located near key market hubs and near its 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.

### Table of Contents

The Partnership's contract portfolio has attractive rate and term characteristics including a significant fee-based component, especially in its Downstream Business and its Badlands operations. The Partnership's expected continued growth of the fee-based Downstream and Badlands businesses may result in increasing fee-based cash flow.

#### Financial flexibility

The Partnership has historically maintained a conservative leverage ratio and ample liquidity and has funded its growth investments with a mix of equity and debt over time. Disciplined management of leverage, liquidity and commodity price volatility allows the Partnership to be flexible in its long-term growth strategy and enables it to pursue strategic acquisitions and large growth projects.

#### Experienced and long-term focused management team

Our current executive management team consists largely of individuals who formed us in 2004. They possess a breadth and depth of combined experience working in the midstream energy business. Other officers and key operational, commercial and financial employees provide significant experience in the industry and with its assets and businesses.

#### Attractive cash flow characteristics

The Partnership believes that its strategy, combined with its high-quality asset portfolio and strong industry fundamentals, allows it to generate attractive cash flows. Geographic, business and customer diversity enhances its cash flow profile. The Partnership's Field Gathering and Processing segment has a favorable contract mix that is primarily percent-of-proceeds, but also has increasing components of fee-based revenues from natural gas treating and compression across its Field Gathering and Processing Businesses and from essentially fully fee-based crude oil gathering and gas gathering and processing in its Bakken Shale assets. Contracts in its Coastal Gathering and Processing segment are primarily hybrid (percent-of-liquids with a fee floor) or percent-of-liquids contracts. The Partnership's favorable contract mix, along with its commodity hedging program, serves to mitigate the impact of commodity price movements on cash flow.

The Partnership has hedged the commodity price risk associated with a portion of its expected natural gas and condensate equity volumes through 2017 and NGL equity volumes through 2015 by entering into financially settled derivative transactions. Historically, these transactions have included both swaps and purchased puts (or floors). The primary purpose of its commodity risk management activities is to hedge its exposure to price risk and to mitigate the impact of fluctuations in commodity prices on cash flow. The Partnership has intentionally tailored its hedges to approximate specific NGL products and to approximate its actual NGL and residue natural gas delivery points. Although the degree of hedging will vary, the Partnership intends to continue to manage some of its exposure to commodity prices by entering into similar hedge transactions. The Partnership also monitors and manages its inventory levels with a view to mitigate losses related to downward price exposure.

#### Asset base well-positioned for organic growth

We believe that the Partnership's asset platform and strategic locations allow the Partnership to maintain and potentially grow its volumes and related cash flows as its supply areas continue to benefit from exploration and development. Technology advances have resulted in increased domestic oil and liquids-rich gas drilling and production activity. While recent commodity price levels may impact activity, the location of its assets provides the Partnership with access to generally stable natural gas and crude oil supplies and proximity to end-user markets and liquid market hubs while positioning the Partnership to capitalize on drilling and production activity in those areas. The Partnership's 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, the Partnership's infrastructure will increase in value as such infrastructure takes on increasing importance in meeting that growing supply and demand.

## Table of Contents

While we have set forth the Partnership's strategies and competitive strengths above, its business involves numerous risks and uncertainties which may prevent the Partnership from executing its strategies or impact the amount of distributions to unitholders. 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 its 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 the Partnership, see "Item 1A. Risk Factors."

### The Partnership's Relationship with Us

We have used the Partnership 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 the Partnership's acquisitions of businesses from us. However, we are not prohibited from competing with the Partnership and may evaluate acquisitions and dispositions that do not involve the Partnership. In addition, through its relationship with us, the Partnership has access to a significant pool of management talent, strong commercial relationships throughout the energy industry and access to our broad operational, commercial, technical, risk management and administrative infrastructure.

As of December 31, 2014, we and our named executive officers and directors have a significant ownership interest in the Partnership through our ownership of approximately 10.9% limited partner interest and our 2% general partner interest. In addition, we own incentive distribution rights that entitle us to receive an increasing percentage of quarterly distributions of available cash from the Partnership's operating surplus after the minimum quarterly distribution and the target distribution levels have been achieved. The Partnership Agreement with us governs our relationship regarding certain reimbursement and indemnification matters. See "Item 13. Certain Relationships and Related Transactions and Director Independence."

The Partnership does not have any employees to carry out its operations. We employ approximately 1,350 people. See "—Employees." We charge the Partnership for all the direct costs of the employees assigned to its operations, as well as all general and administrative support costs other than its direct support costs of being a separate reporting company and our cost of providing management and support services to certain unaffiliated spun-off entities. The Partnership generally reimburses us for cost allocations to the extent that the Partnership has required a current cash outlay by us.

### The Partnership's Challenges

The Partnership faces a number of challenges in implementing its business strategy. For example:

- The Partnership has a substantial amount of indebtedness which may adversely affect its financial position.

- The Partnership's 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.

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

- If the Partnership does not successfully integrate assets from acquisitions, its results of operations and financial condition could be adversely affected.

- If the Partnership does not make acquisitions or investments in new assets on economically acceptable terms or efficiently and effectively integrate new assets, the Partnership's results of operations and financial condition could be

adversely affected.

The Partnership is subject to regulatory, environmental, political, legal and economic risks, which could adversely affect the Partnership's results of operations and financial condition.

The Partnership's growth strategy requires access to new capital. Tightened capital markets or increased competition for investment opportunities could impair the Partnership's ability to grow.

Table of Contents

The Partnership's hedging activities may not be effective in reducing the variability of the Partnership's cash flows and may, in certain circumstances, increase the variability of the Partnership's cash flows.

The Partnership's industry is highly competitive, and increased competitive pressure could adversely affect the Partnership's business and operating results.

In addition, risks and uncertainties related to the Atlas Mergers and the related transactions include:

The Partnership's ability to complete the proposed merger of APL and the ability of us to complete the proposed merger of ATLS, upon which the closing of the APL Merger is conditioned, on the anticipated terms and time frame.

Risks relating to obtaining the approval of our stock issuance in connection with the ATLS Merger by our stockholders and the approval of the Atlas Mergers by the unitholders of ATLS and APL, as applicable, and to satisfying the other conditions to the consummation of the Atlas Mergers.

The potential impact of the announcement or consummation of the Atlas Mergers on our relationships, including with employees, suppliers, customers, competitors and credit rating agencies.

The ability of the Partnership and us to integrate with APL successfully after consummation of the APL Merger and to achieve anticipated benefits from the proposed transaction.

· Risks relating to any unforeseen liabilities of APL.

· General economic, market and business conditions.

· Any acquisition, including the Atlas Mergers, involves potential risks, including, among other things:

§ the validity of our assumptions about, among other things, revenues and costs, including synergies;

§ an inability to integrate successfully the businesses we and the Partnership acquire;

§ a decrease in our and the Partnership's liquidity by using a significant portion of available cash or borrowing capacity to finance acquisitions;

§ a significant increase in our and the Partnership's interest expense or financial leverage if we or the Partnership incurs additional debt to finance acquisitions;

§ the assumption of unknown liabilities, losses or costs for which we are not indemnified or for which the Partnership's indemnity is inadequate;

§ the diversion of management's attention from other business concerns;

§ an inability to hire, train or retain qualified personnel to manage and operate the Partnership's growing business and assets;

§ the incurrence of other significant charges, such as impairment of goodwill or other intangible assets, asset devaluation or restructuring charges;

§ unforeseen difficulties encountered in operating in new geographic areas; and

§ customer or key employee losses at the acquired businesses.

Failure to complete the Atlas Mergers could negatively affect the Partnership's future business and financial results.

For a further discussion of these and other challenges the Partnership faces, please read "Item 1A. Risk Factors."

13

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## Table of Contents

### The Partnership's Business Operations

The Partnership's 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

The Partnership's 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. The Partnership sells its 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 its 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.

The Partnership continually seeks new supplies of natural gas and crude oil, both to offset the natural decline in production from connected wells and to increase throughput volumes. The Partnership obtains additional natural gas and crude oil supply in its 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, service levels and access to markets. The commercial terms of natural gas gathering and processing arrangements and crude oil gathering are driven, in part, by capital costs, which are impacted by the proximity of systems to the supply source and by operating costs, which are impacted by operational efficiencies, facility design and economies of scale.

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

#### Field Gathering and Processing Segment

In 2014, the Field Gathering and Processing segment gathered and processed natural gas from the Permian Basin in West Texas and Southeast New Mexico, the Fort Worth Basin, including the Barnett Shale, in North Texas and the Williston Basin in North Dakota. The natural gas processed in this segment is supplied through its gathering systems which, in aggregate, consist of approximately 11,400 miles of natural gas pipelines and include twelve owned and operated processing plants. During 2014, the Partnership processed an average of 921.2 MMcf/d of natural gas and produced an average of 105.9 MBbl/d of NGLs. In addition to the Partnership's natural gas gathering and processing, its Badlands operations include a crude oil gathering system and four terminals with crude oil operational storage capacity of 125 MBbl.

The Partnership believes it is well positioned as a gatherer and processor in the Permian, Fort Worth and Williston Basins. The Partnership believes proximity to production and development activities allows it to compete for new supplies of natural gas and crude oil partially because of its lower competitive cost and to connect new wells and to process additional natural gas in its existing processing plants and because of its reputation for reliability. Additionally, because the Partnership operates all of its plants, which are often interconnected in these regions, it is often able to redirect natural gas among its processing plants, providing operational flexibility and allowing it to optimize processing efficiency and further improve the profitability of its operations.

## Table of Contents

In October 2014, the Partnership announced the approval of the purchase and installation of new processing plants in the Delaware Basin in Texas and the Williston Basin in North Dakota. See “Growth Investments in the Permian and Williston Basins.”

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

### Sand Hills

The Sand Hills operations consist of the Sand Hills and Puckett gathering systems in West Texas. These systems consist of approximately 1,600 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 175 MMcf/d and residue gas connections to pipelines owned by affiliates of Enterprise Products Partners L.P. (“EPP”), Kinder Morgan, Inc. (“Kinder Morgan”) and ONEOK, Inc. (“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 consists of approximately 3,350 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 the Partnership’s ownership interest). These plants have residue gas connections to pipelines owned by affiliates of Kinder Morgan and MidAmerican Energy Company. The Partnership’s ownership in Versado is held through Versado Gas Processors, L.L.C., a consolidated joint venture that is 63% owned by the Partnership and 37% owned by Chevron U.S.A. Inc.

### SAOU

SAOU includes approximately 1,750 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”), EPP, Kinder Morgan, Northern Natural Gas Company and ONEOK.

### North Texas

North Texas includes two interconnected gathering systems with approximately 4,500 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, EPP and Natural Gas Pipeline Company of America LLC.

The Chico gathering system consists of approximately 2,450 miles of gathering pipelines. 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 2,050 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.

#### Badlands

The Badlands operations are located in the Bakken and Three Forks Shale plays of the Williston Basin in North Dakota and include approximately 360 miles of crude oil gathering pipelines, 40 MBbl of operational crude storage capacity at the Johnsons Corner Terminal, and 30 MBbl of operational crude storage capacity at the Alexander Terminal. During 2014, the Partnership completed the construction of an additional 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 170 miles of natural gas gathering pipelines and the Little Missouri natural gas processing plant with a gross processing capacity of approximately 50 MMcf/d. A third train is currently being installed at the Little Missouri plant site which will increase processing capacity by an incremental 40 MMcf/d and is expected to be mechanically complete in January 2015. This will bring the total processing capacity to approximately 90 MMcf/d.

15

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Table of Contents

During 2014, the Partnership invested approximately \$165 million to expand its Badlands crude oil gathering and gas gathering and processing systems, including the natural gas processing plant mentioned above.

The following table lists the Field Gathering and Processing segment's processing plants and related volumes for the year ended December 31, 2014:

Facility	% Owned	Location	Estimated Gross Processing Capacity (MMcf/d)(1)	Gross Plant Natural Gas Inlet Throughput Volume (MMcf/d) (2) (3)	Gross NGL Production (MBbl/d) (2) (3)	Process Type (4)	
Sand Hills							
Sand Hills	100	Crane, TX	175.0	158.7	18.0	Cryo	Operated
Puckett (5)			-	6.4	-		
		Area Total	175.0				
Versado (6) (7)							
Saunders	63	Lea, NM	60.0	36.1	4.2	Cryo	Operated
Eunice	63	Lea, NM	95.0	78.2	10.2	Cryo	Operated
Monument	63	Lea, NM	85.0	55.3	6.9	Cryo	Operated
		Area Total	240.0				
SAOU							
Mertzon	100	Irion, TX	52.0	49.6	7.5	Cryo	Operated
Sterling	100	Sterling, TX	92.0	68.3	10	Cryo	Operated
Conger	100	Sterling, TX	25.0	17.4	2.2	Cryo	Operated
High Plains	100	Midland, TX	200.0	99.8	9.6	Cryo	Operated
		Area Total	369.0				
North Texas							
Chico (8)	100	Wise, TX	265.0	219.7	21.5	Cryo	Operated
Shackelford	100	Shackelford, TX	13.0	9.6	1.2	Cryo	Operated
Longhorn	100	Wise, TX	200.0	143.3	15.4	Cryo	Operated
		Area Total	478.0				
Badlands							
Little Missouri (9)	100	McKenzie, ND	50.0	38.9	3.5	RA	Operated
		Segment System Total	1,312.0				

Gross processing capacity represents 100% of ownership interests and may differ from nameplate processing (1) 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.

Per day Gross Plant Natural Gas Inlet and NGL Production statistics for plants listed above are based on the number of days operational during 2014. The Longhorn plant and the High Plains plant became fully operational in (3) May 2014 and June 2014 respectively. The Conger plant was idled due to current market conditions in September 2014.

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

(5) Puckett volumes are gathered in the Partnership's pipelines and processed at third-party plants.

(6)

Plant natural gas inlet and NGL production volumes represent 100% of ownership interests for the Partnership's consolidated Versado joint venture.

(7) Includes throughput other than plant inlet, primarily from compressor stations.

(8) The Chico plant has fractionation capacity of approximately 15 MBbl/d.

Additional residue compression was added in 2014, bringing the nominal gas plant throughput capacity to 50

(9) MMcf/d. An additional 40 MMcf/d expansion, anticipated for the first quarter of 2015, will increase the nominal capacity to 90 MMcf/d.

#### Coastal Gathering and Processing Segment

The Partnership's 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 its assets in Louisiana, the Partnership has 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 2014, the Partnership processed an average of 1,188.4 MMcf/d of plant natural gas inlet and produced an average of 47.1 MBbl/d of NGLs.

Table of Contents

LOU

LOU consists of approximately 1,000 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 the Partnership. 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 its Venice, Lowry and Barracuda plants.

VESCO

Through the Partnership's 76.8% ownership interest in Venice Energy Services Company, L.L.C., it operates 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 three wholly owned and operated gas processing plants (one now idled) and three partially owned plants which are not operated by the Partnership. 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 the Partnership. The Pelican and Seahawk gathering systems have a combined length of approximately 175 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.

Table of Contents

The following table lists the Coastal Gathering and Processing segment's natural gas processing plants and related volumes for the year ended December 31, 2014:

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)	
<b>LOU</b>							
Gillis (6)	100	Calcasieu, LA	180.0	165.6	6.9	Cryo	Operated
Acadia (7)	100	Acadia, LA	80.0	3.2	0.1	Cryo	Operated
Big Lake	100	Calcasieu, LA	180.0	115.7	1.9	Cryo	Operated
		Area Total	440.0				
VESCO (8)	76.8	Plaquemines, LA	750.0	509.0	26.0	Cryo	Operated
<b>Other Coastal Straddles (7)</b>							
Barracuda	100	Cameron, LA	190.0	126.9	43.7	Cryo	Operated
Lowry	100	Cameron, LA	265.0	138.7	4.0	Cryo	Operated
Terrebone	4.6	Terrebonne, LA	950.0	22.6	0.6	RA	Non-operated
Toca	9.2	St. Bernard, LA	1,150.0	35.4	1.0	Cryo/RA	Non-operated
Sea Robin	0.8	Vermillion, LA	700.0	20.7	0.7	Cryo	Non-operated
Other (10)			-	50.5	2.1		
		Area Total	3,255.0				
		Consolidated System Total	4,445.0				

(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 the Partnership's consolidated VESCO joint venture and the Partnership's ownership share of volumes for other partially owned plants which the Partnership proportionately consolidate based on its ownership interest which is adjustable subject to an annual redetermination based on its 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 2014. The Big Lake facility was idled in November 2014 due to current narrow processing spreads.

(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 as conditions on the LOU system 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) Other includes Neptune volumes processed at third party plants.

#### Logistics and Marketing Division

The Partnership's 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 the Partnership's 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 crop drying 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. The Partnership's logistics assets are generally connected to, and supplied in part by, its 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).

18

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## Table of Contents

### 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.

The Partnership’s fractionation assets include ownership interests in three stand-alone fractionation facilities that are located on the Gulf Coast, two that it operates, one at Mont Belvieu, Texas and the other at Lake Charles, Louisiana. The Partnership has an equity investment in the third fractionator, GCF, also located at Mont Belvieu. The Partnership is subject to a consent decree with the Federal Trade Commission, issued December 12, 1996, that, among other things, prevents it from participating in commercial decisions regarding rates paid by third parties for fractionation services at GCF. This restriction on the Partnership’s 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 the Gathering and Processing division.

The Partnership expanded the fractionation capacity of its assets during the last three years with the following projects:

CBF Train 4. In August 2013, the Partnership commissioned 100 MBbl/d of additional fractionation capacity, Train 4, at CBF, in Mont Belvieu, Texas, at a gross cost of approximately \$385 million (the Partnership’s 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.

GCF expansion. In the second quarter of 2012, GCF, a partnership with Phillips 66 and Devon Energy Corporation, in which the Partnership owns a 38.8% interest, completed an expansion to increase the capacity of its NGL fractionation facility in Mont Belvieu. The gross cost was approximately \$92 million (the Partnership’s net cost was approximately \$35 million) for an estimated ultimate capacity of approximately 125 MBbl/d.

In August 2014, the Partnership began purchasing equipment for Train 5, which is currently under construction. This expansion will add 100 MBbl/d of fractionation capacity. The gross cost of Train 5 is expected to be approximately \$385 million and will be supported by supply from Targa’s Gas Processing Division and by long-term contracts with third parties.

The Partnership’s 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 the Partnership’s NGL fractionation business are dependent upon the volume of mixed NGLs fractionated, the level of fractionation fees charged and product gains/losses from fractionation.

The Partnership believes that sufficient volumes of mixed NGLs will be available for fractionation in commercially viable quantities for the foreseeable future due to increases in NGL production expected 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 the Partnership’s 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. The Partnership believes that the location, scope and capability of the Partnership's logistics assets, including its transportation and distribution systems, gives the Partnership access to both substantial sources of mixed NGLs and a large number of end-use markets.

19

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Table of Contents

The Partnership also has a natural gasoline hydrotreater at Mont Belvieu, Texas that removes sulfur from natural gasoline, allowing customers to meet new, more stringent environmental standards. In 2012, the Partnership completed modifications to the hydrotreater to add the capability to reduce benzene content of natural gasoline to meet new, even more stringent environmental standards for one of its long-term customer accounts. 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 2014 (MBbl/d)
Operated Facilities:			
Lake Charles Fractionator (Lake Charles, LA)	100.0	55.0	25.7
Cedar Bayou Fractionator (Mont Belvieu, TX) (2)	88.0	393.0	313.7
Targa LSNG Hydrotreater (Mont Belvieu, TX)	100.0	30.0	
LSNG treating volumes			23.4
Benzyne treating volumes			23.4
Non-operated Facilities:			
Gulf Coast Fractionators (Mont Belvieu, TX)	38.8	125.0	114.0

(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, the Partnership's 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, the Partnership's terminaling operations provide the inbound/outbound logistics and warehousing of mixed NGLs, NGL products and petrochemical products in above-ground storage tanks. The Partnership's 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 the Partnership's facilities are connected to marine, rail and truck loading and unloading facilities that provide services and products to customers. The Partnership provides long and short-term storage and terminaling services and throughput capability to third-party customers for a fee.

The Partnership's Petroleum Logistics business owns and operates storage and terminaling facilities in Texas, Maryland and Washington. These facilities primarily not only serve the refined petroleum products and crude oil markets, but also include LPGs and biofuels.

Across the Logistics Assets segment, the Partnership owns or operates a total of 39 storage wells at its 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.

The Partnership operates its storage and terminaling facilities to support its 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 its wholesale terminals that focus on logistics to service its heating market customer base. In September 2013, the Partnership commissioned Phase I of the international export expansion project that includes facilities at both Mont Belvieu and the Galena Park Marine Terminal near Houston, Texas. Phase I of the project expanded its 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, the Partnership also added capabilities to load VLGC vessels alongside the small and medium sized export vessels that it loads for export. The Partnership 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. The Partnership continues to experience significant demand growth for NGL (primarily propane) exports.

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

Table of Contents

The following table details the Logistics Assets NGL storage facilities at December 31, 2014:

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	20 (2)	43.7
Easton Storage	100	Evangeline, LA	1 (3)	0.8

(1) 5 of 12 owned wells leased to CITGO Petroleum Corporation under long-term leases.

Excludes 5 non-owned wells the Partnership operates on behalf of Chevron Phillips Chemical Company LLC

(2) ("CPC"). The first of 4 new permitted wells has been drilled and washed and is in the process of being connected for hydrocarbon service. The second new well has been drilled and is in the process of being washed.

(3) Will be deactivated during 2015 by order of Louisiana Department of Natural Resources.

The following table details the Logistics Assets NGL and Petroleum Terminal Facilities for the year ended December 31, 2014:

Facility	% Owned	Location	Description	Throughput for 2014 (Million gallons)	Usable Storage Capacity (MMBbl)
Galena Park Terminal (1)	100	Harris, TX	NGL import/export terminal, chemicals	3,537.5	0.7
Mont Belvieu Terminal	100	Chambers, TX	Transport and storage terminal	12,934.5	39.3
Hackberry Terminal	100	Cameron, LA	Storage terminal	1,041.3	17.8
Channelview Terminal	100	Harris, TX	Refined products, crude - transport and storage terminal	202.8	0.5
Baltimore Terminal	100	Baltimore, MD	Refined products - transport and storage terminal	-	0.5
Sound Terminal	100	Pierce, WA	Refined products, crude oil/propane - transport and storage terminal	467.8	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. The Partnership owns or commercially manages terminal facilities in a number of states, including Texas, Louisiana, Arizona, Nevada, California, Florida, Alabama, Mississippi, Tennessee, Kentucky, New Jersey and Washington. The geographic diversity of the Partnership's 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 Marketing, (iii) Refinery Services, (iv) Commercial Transportation, (v) Natural Gas Marketing and (vi) Terminal Facilities, each as described below.

#### NGL Distribution and Marketing

The Partnership markets its own NGL production and also purchases component NGL products from other NGL producers and marketers for resale. Additionally, the Partnership also purchases product for resale in its Logistics segment, including exports. During the year ended December 31, 2014, its distribution and marketing services business sold an average of approximately 423.3 MBbl/d of NGLs.

The Partnership generally purchases 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 the Partnership earns margins from purchasing and selling NGL products from customers under contract. The Partnership also earns margins by purchasing and reselling NGL products in the spot and forward physical markets. To effectively serve its Distribution and Marketing customers, the Partnership contracts for and uses many of the assets included in its Logistics Assets segment.

#### Wholesale Marketing

The Partnership's wholesale propane marketing operations primarily sell propane and related logistics services to major multi-state retailers, independent retailers and other end-users. The Partnership's propane supply primarily originates from both its refinery/gas supply contracts and other owned or managed logistics and marketing assets. The Partnership generally sells propane at a fixed or posted price at the time of delivery and, in some circumstances, it earns margin on a netback basis.

Table of Contents

The wholesale propane marketing business is significantly impacted by seasonal and weather-driven demand, particularly in the winter, which can impact the price of propane in the markets the Partnership serves and impact the ability to deliver propane to satisfy peak demand.

Refinery Services

In the Partnership's refinery services business, it typically provides NGL balancing services via contractual arrangements with refiners to purchase and/or market propane and to supply butanes. The Partnership uses its commercial transportation assets (discussed below) and contracts for and uses the storage, transportation and distribution assets included in its 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 those same refining processes. Under typical netback purchase contracts, the Partnership generally retains a portion of the resale price of NGL sales or receives 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 the Partnership's refinery services business include production volumes, prices of propane and butanes, as well as its ability to perform receipt, delivery and transportation services in order to meet refinery demand.

Commercial Transportation

The Partnership's NGL transportation and distribution infrastructure includes a wide range of assets supporting both third-party customers and the delivery requirements of its marketing and asset management business. The Partnership provides fee-based transportation services to refineries and petrochemical companies throughout the Gulf Coast area. The Partnership's assets are also deployed to serve its 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 the Partnership's customers.

The Partnership's transportation assets, as of December 31, 2014, include 716 railcars that the Partnership leases and manages, 75 owned and leased transport tractors and 22 company-owned pressurized NGL barges.

Table of Contents

## Natural Gas Marketing

The Partnership also markets natural gas available to it from the Gathering and Processing segments, purchases and resells natural gas in selected United States markets and manages 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 2014 (Million gallons) (1)	Usable Storage Capacity (Million gallons)
Calvert City Terminal	100	Marshall, KY	Propane terminal	11.6	0.1
Greenville Terminal	100	Washington, MS	Marine propane terminal	22.5	1.5
Port Everglades Terminal	100	Broward, FL	Marine propane terminal	8.9	1.6
Tyler Terminal	100	Smith, TX	Propane terminal	11.1	0.2
Abilene Transport (2)	100	Taylor, TX	Raw NGL transport terminal	19.5	0.1
Bridgeport Transport (2)	100	Jack, TX	Raw NGL transport terminal	28.8	0.1
Gladewater Transport (2)	100	Gregg, TX	Raw NGL transport terminal	15.2	0.3
Chattanooga Terminal	100	Hamilton, TN	Propane terminal	12.7	0.9
Sparta Terminal	100	Sparta, NJ	Propane terminal	15.7	0.2
Hattiesburg Terminal (3)	50	Forrest, MS	Propane terminal	329.3	302.0
Winona Terminal	100	Flagstaff, AZ	Propane terminal	15.6	0.3
Sound Terminal (4)	100	Pierce, WA	Propane terminal	5.4	0.2

(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.

## Operational Risks and Insurance

The Partnership is subject to all risks inherent in the midstream natural gas, crude oil and petroleum logistics businesses. These risks include, but are not limited to, explosions, fires, mechanical failure, terrorist attacks, product spillage, weather, nature and inadequate maintenance of rights-of-way and could result in damage to or destruction of operating assets and other property, or could result in personal injury, loss of life or environmental pollution, as well as curtailment or suspension of operations at the affected facility. We maintain, on behalf of ourselves and our subsidiaries, including the Partnership, general public liability, property, boiler and machinery and business interruption insurance in amounts that we consider to be appropriate for such risks. Such insurance is subject to deductibles that we consider reasonable and not excessive given the current insurance market environment. 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 in September 2008. As a result, the Partnership 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 the Partnership's operations and the Partnership's and our 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 the Partnership business operations and the Partnership's and our 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

The Partnership faces 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 the Partnership's 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. The Partnership's major competitors for natural gas supplies in our current operating regions include APL, Kinder Morgan, WTG Gas Processing, L.P. ("WTG"), DCP Midstream Partners LP ("DCP"), Devon Energy Corporation ("Devon"), Enbridge Inc., Enlink Midstream Partners, Regency Energy Partners LP, ONEOK Rockies Midstream, L.L.C., 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. The Partnership's competitors for crude oil gathering services in North Dakota include Arrow Midstream Holdings, LLC, Hiland Partners, LP, Great Northern Midstream LLC, Caliber Midstream Partners, L.P. and Bridger Pipeline LLC. The Partnership's competitors may have greater financial resources than it possesses.

### Table of Contents

The Partnership also competes for NGL products to market through its Logistics and Marketing division. The Partnership's competitors include major oil and gas producers who market NGL products for their own account and for others. Additionally, the Partnership competes with several other NGL marketing companies, including EPP, DCP, ONEOK and BP p.l.c.

Additionally, the Partnership faces competition for mixed NGLs supplies at its fractionation facilities. Its competitors include large oil, natural gas and petrochemical companies. The fractionators in which the Partnership owns 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. The Partnership's other fractionation facilities compete for mixed NGLs with the fractionators at Mont Belvieu as well as other fractionation facilities located in Louisiana. The Partnership's 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 the Partnerships' services. Its primary competitor in providing export services to its customers is EPP.

### Regulation of Operations

Regulation of pipeline gathering and transportation services, natural gas sales and transportation of NGLs may affect certain aspects of the Partnership's business and the market for its 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.



## Table of Contents

### Gathering Pipeline Regulation

The Partnership's natural gas gathering operations are typically subject to ratable take and common purchaser statutes in the states in which it operates. 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 the Partnership's ability as an owner of gathering facilities to decide with whom it contracts to gather natural gas. The states in which the Partnership operates 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 the Partnership charges for gathering are deemed just and reasonable unless challenged in a complaint. We cannot predict whether such a complaint will be filed against the Partnership 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. The Partnership believes that the natural gas pipelines in its 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 the Partnership's 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 the Partnership's natural gas intrastate pipelines are not subject to regulation by FERC as natural gas companies under the NGA, the Partnership's 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."

The Partnership's intrastate pipelines located in Texas are regulated by the Railroad Commission of Texas (the "RRC"). The Partnership's Texas intrastate pipeline, Targa Intrastate Pipeline LLC ("Targa Intrastate"), owns the intrastate pipeline that transports natural gas from the Partnership's 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. The Partnership's 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.

The Partnership's Louisiana intrastate pipeline, Targa Louisiana Intrastate LLC ("TLI") 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.

Texas and Louisiana have adopted complaint-based regulation of intrastate natural gas transportation activities, which allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to pipeline access and rate discrimination. The rates the Partnership charges for intrastate transportation are

deemed just and reasonable unless challenged in a complaint. We cannot predict whether such a complaint will be filed against the Partnership in the future. Failure to comply with state regulations can result in the imposition of administrative, civil and criminal penalties.

## Table of Contents

The Partnership's intrastate NGL pipelines in Louisiana gather mixed NGLs streams that it owns 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 its 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.

The Partnership's 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

The Partnership's natural gas gathering and processing operations are not presently subject to FERC regulation. However, since May 2009, the Partnership has been required to report to FERC information regarding natural gas sale and purchase transactions for some of its 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 the Partnership's processing operations will continue to be exempt from other FERC regulation in the future.

### Sales of Natural Gas and NGLs

The price at which the Partnership buys and sells 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 the Partnership's physical purchases and sales of these energy commodities and any related hedging activities that the Partnership undertakes, it is 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—Domenici-Barton Energy Policy Act of 2005 ("EP Act of 2005")." Since May 1, 2009, the Partnership has been required to report to FERC information regarding natural gas sale and purchase transactions for some of the Partnership's 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 the Partnership violate the anti-market manipulation laws and regulations, it 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

The Partnership's 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 the Partnership operates a significant portion of its 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 the Partnership's 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 runs 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 the Partnership maintain tariffs on file with FERC for each of these pipelines. Those tariffs set forth the rates the Partnership charges 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 subsidiaries of the Partnership.

## Table of Contents

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 waiver, the Partnership 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 the Partnership's results of operations.

## Other Federal Laws and Regulations Affecting Our Industry

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 the Partnership's 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 the Partnership's Hinshaw pipelines.

## Table of Contents

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 the Partnership's natural gas operations. We do not believe that the Partnership would be affected by any such FERC action materially differently than other midstream natural gas companies with whom it competes.

### Environmental and Operational Health and Safety Matters

#### General

The Partnership's operations are subject to stringent and complex 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 the Partnership's overall cost of business, including its capital costs to construct, maintain and upgrade equipment and facilities. These laws and regulations may, among other things; require the acquisition of various permits to conduct regulated activities; require the installation of pollution control equipment or otherwise restrict the way the Partnership can handle or dispose of wastes; limit or prohibit construction activities in sensitive areas such as wetlands, wilderness or urban areas or areas inhabited by endangered or threatened species; impose specific health and safety criteria addressing worker protection; require investigatory and remedial action to mitigate pollution conditions caused by its operations or attributable to former operations; and enjoin some or all of the operations of facilities deemed in non-compliance with permits issued pursuant to such environmental laws and regulations. Failure to comply with these laws and regulations may result in assessment of administrative, civil and criminal penalties, the imposition of removal or remedial obligations and the issuance of injunctions limiting or prohibiting the Partnership's activities. For example, the Texas Commission on Environmental Quality issued Notices of Enforcement dated August 22, 2014 and September 9, 2014 to Targa Midstream Services LLC for alleged violations of air emissions regulations at the Mont Belvieu Fractionator relating to operation of two regenerative thermal oxidizers during 2013 and 2014 and an unrelated discrete emissions event that occurred on May 29, 2014. The Partnership is in discussions with the agency to resolve the alleged violations by combining the notices into one order that we believe could result in a monetary sanction in excess of \$100,000 but less than \$280,000.

The Partnership has implemented programs and policies designed to keep its pipelines, plants and other facilities in compliance with existing environmental laws and regulations. The clear trend in environmental regulation, however, 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 the Partnership's operations and financial position. The Partnership may be unable to pass on such increased compliance costs to its customers. Moreover, accidental releases or spills may occur in the course of the Partnership's operations and we cannot assure you that the Partnership will not incur significant costs and liabilities as a result of such releases or spills, including any third-party claims for damage to property or natural resources or injury to persons. While we believe that the Partnership is in substantial compliance with existing environmental laws and regulations and that continued compliance with current legal requirements would not have a material adverse effect on the Partnership, there is no assurance that the current regulatory standards will not become more onerous in the future.

The following is a summary of the more significant existing environmental and worker health and safety laws and regulations to which the Partnership's business operations are subject and for which compliance may have a material adverse impact on the Partnership's capital expenditures, results of operations or financial position.

#### Hazardous Substances and Waste

The Comprehensive Environmental Response, Compensation, and Liability Act, as amended ("CERCLA"), and comparable state laws impose liability, without regard to fault or the legality of the original conduct, 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. Under CERCLA, these “responsible persons” may be subject to joint and several, strict liability for 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 the responsible classes of 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. The Partnership generates materials in the course of its 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 sites at which these hazardous substances have been released into the environment.

## Table of Contents

The Partnership also generates solid wastes, including hazardous wastes that are subject to the requirements of the Resource Conservation and Recovery Act, as amended (“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 the Partnership’s operations, it generates petroleum product wastes and ordinary industrial wastes such as paint wastes, waste solvents and waste compressor oils that are regulated as hazardous wastes. Certain materials generated in the exploration, development or production of crude oil and natural gas are excluded from RCRA’s hazardous waste regulations. However, it is possible that future changes in law or regulation could result in these wastes, including wastes currently generated during the Partnership’s 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 the Partnership’s capital expenditures and operating expenses as well as those of the oil and gas industry in general.

The Partnership currently owns or leases and has 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. Although the Partnership has utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other substances and wastes may have been disposed of or released on or under the properties owned or leased by the Partnership 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 disposal or release of hydrocarbons or other substances and wastes was not under the Partnership’s control. These properties and any hydrocarbons, substances and wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, the Partnership could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) and to perform remedial operations to prevent future contamination. We are not currently aware of any facts, events or conditions relating to such requirements that would reasonably be expected to have a material adverse effect on the Partnership’s results of operations or financial condition.

## Air Emissions

The federal Clean Air Act, as amended, 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 the Partnership 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, the Partnership may be required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. For example, in December 2014, the EPA published proposed regulations to revise the National Ambient Air Quality Standard (“NAAQS”) for ozone, recommending a standard between 65 to 70 parts per billion (“ppb”) for both the 8-hour primary and secondary standards. The current primary and secondary ozone standards are set at 75 ppb. The EPA requested public comments on whether the standard should be set as low as 60 ppb or whether the existing 75 ppb standard should be retained. The EPA anticipates issuing a final rule by October 1, 2015. If the EPA lowers the ozone standard, states could be required to implement new more stringent regulations, which could apply to the Partnership’s operations. Compliance with these or other new regulations could, among other things, require installation of new emission controls on some of the Partnership’s equipment, result in longer permitting timelines, and significantly increase the Partnership’s capital expenditures and operating costs, which could adversely impact the Partnership’s business.

Table of Contents

Climate Change

In December 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases (“GHGs”) present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, 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 that, among other things, restrict emissions of GHGs from motor vehicles as well as establish Prevention of Significant Deterioration (“PSD”) construction and Title V operating permit reviews for GHG emissions from certain large stationary sources that are also potential major sources of certain principal, or criteria, pollutant emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet “best available control technology” standards that typically are established by the states. 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. On December 9, 2014, the EPA published a proposed rule that would expand the petroleum and natural gas system sources for which annual GHG emissions reporting is currently required to include GHG emissions reporting beginning in the 2016 reporting year for 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. The Partnership is monitoring GHG emissions from certain of its operations in accordance with current GHG emissions reporting requirements in a manner that it believes is in substantial compliance with applicable reporting obligations and is currently assessing the potential impact that the December 9, 2014 proposed rule may have on its future reporting obligations, should the proposed rule be adopted.

Also, Congress has from time to time considered legislation to reduce emissions of GHGs, and 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 that typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. The adoption of any legislation or regulations that requires reporting of GHGs or otherwise restricts emissions of GHGs from the Partnership or its customers equipment and operations could require the Partnership or its customers to incur significant added costs to reduce emissions of GHGs or could adversely affect demand for the natural gas and NGLs it gathers and processes or fractionates. 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 the Partnership’s or its customers’ operations.

Water Discharges

The Federal Water Pollution Control Act, as amended (“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 the Partnership 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 can impose substantial, civil and criminal penalties for non-compliance including spills and other non-authorized discharges.

The Federal Oil Pollution Act of 1990, as amended (“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 the Partnership’s plants, and 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. We believe that the Partnership is in substantial compliance with the CWA, the OPA and analogous state laws.

## Table of Contents

### Hydraulic Fracturing

It is customary to recover natural gas from deep shale formations through the use of hydraulic fracturing, combined with sophisticated horizontal drilling. 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, which plans to propose effluent limit guidelines in the first half of 2015 for waste water from shale gas extraction operations before being discharged to a treatment plant, and the Bureau of Land Management, which proposed regulations in May 2013 applicable to hydraulic fracturing conducted on federal and Indian oil and natural gas leases and is expected to issue a final rule in the first half of 2015. 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 Governor Andrew Cuomo of the State of New York announced in December 2014 with regard to fracturing activities in New York. 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, with the EPA planning to issue a draft of its final report on hydraulic fracturing in the first half of 2015. These studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing. While the Partnership does 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 the Partnership's 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 the Partnership's gathering, processing and fractionation services.

### Endangered Species Act Considerations

The federal Endangered Species Act, as amended ("ESA"), restricts activities that may affect endangered or threatened species or their habitats. While some of the Partnership's facilities may be located in areas that are designated as habitat for endangered or threatened species, we believe that the Partnership is in substantial compliance with the ESA. If endangered species are located in areas of the underlying properties where the Partnership wishes 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. For example, in March 2014, the FWS listed the lesser prairie chicken as a threatened species in a five-state region, including Texas and New Mexico, where the Partnership and its customers conduct operations. The designation of previously unprotected species as threatened or endangered in areas where the Partnership or its oil and natural gas exploration and production customers operate could cause the Partnership or its customers to incur increased costs arising from species protection measures and could result in delays or limitations in its customers' performance of operations, which could reduce demand for the Partnership's midstream services.

### Employee Health and Safety

The Partnership is subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act, as amended ("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 the Partnership's operations and that this information be provided to employees, state and local government authorities and citizens. The Partnership and the entities in which it owns 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 is exempt. The Partnership has an internal program of inspection designed to monitor and enforce compliance with worker safety requirements. We believe that the Partnership is in substantial compliance with all applicable laws and regulations relating to worker health and safety.

Table of Contents

Pipeline Safety

Many of the Partnership's natural gas, NGL and crude pipelines are subject to regulation by the Pipeline and Hazardous Materials Safety Administration ("PHMSA") of the DOT under the Natural Gas Pipeline Safety Act of 1968, as amended ("NGPSA"), with respect to natural gas, and the Hazardous Liquids Pipeline Safety Act of 1979, as amended ("HLPSA"), with respect to crude oil, NGLs and condensates. 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, as amended, 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. We believe that the Partnership's pipeline operations are in substantial compliance with applicable NGPSA and HLPSA requirements; however, due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, future compliance with the NGPSA and HLPSA could result in increased costs.

These pipeline safety laws were amended on January 3, 2012, when President Obama signed 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 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. The Partnership currently estimates an annual average cost of \$2.5 million for the years 2015 through 2017 to perform necessary integrity management program testing on its 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 the Partnership's financial condition or results of operations.

The Partnership, or the entities in which it owns 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 the Partnership and similarly situated midstream operators. For instance, in August 2011, PHMSA published an advance notice of proposed rulemaking in which the agency was seeking public comment on a number

of changes to regulations governing the safety of gas transmission pipelines and gathering lines, including, for example, revising 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 report to Congress from the U.S. Government Accountability Office (“GAO”), the GAO acknowledged PHMSA’s August 2011 proposed rulemaking as well as PHMSA’s continued assessment of the safety risks posed by gathering lines. In its report, the GAO 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.

### Table of Contents

Finally, notwithstanding the applicability of the OSHA's Process Safety Management ("PSM") regulations and the EPA's Risk Management Plan ("RMP") requirements at regulated facilities, PHMSA and one or more state regulators, including the RRC, have recently 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. These recent actions by PHMSA are currently subject to judicial and administrative challenges by one or more midstream operators; however, to the extent that such challenges are unsuccessful, 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 PSM and 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.

### Title to Properties and Rights-of-Way

The Partnership's real property falls into two categories: (1) parcels that it owns in fee and (2) parcels in which its interest derives from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities permitting the use of such land for its operations. Portions of the land on which the Partnership's plants and other major facilities are located are owned by the Partnership in fee title and we believe that the Partnership has satisfactory title to these lands. The remainder of the land on which the Partnership plant sites and major facilities are located is held by the Partnership pursuant to ground leases between the Partnership, as lessee, and the fee owner of the lands, as lessors. The Partnership and its predecessors have leased these lands for many years without any material challenge known to the Partnership relating to the title to the land upon which the assets are located, and we believe that the Partnership has 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 the Partnership has satisfactory title to all of its material leases, easements, rights-of-way, permits, leases and licenses.

### Employees

Through a wholly-owned subsidiary of ours, we employ approximately 1,350 people who primarily support the Partnership's operations. None of those employees are covered by collective bargaining agreements. We consider our employee relations to be good.

### Financial Information by Reportable Segment

See "Segment Information" included under Note 24 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 and the Partnership's 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.

Table of Contents

Item 1A. Risk Factors.

The nature of our business activities subjects us to certain hazards and risks. You should consider carefully the following risk factors together with all 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

Our cash flow is dependent upon the ability of the Partnership to make cash distributions to us.

Our cash flow consists entirely of cash distributions from the Partnership. The amount of cash that the Partnership will be able to distribute to its partners, including us, each quarter principally depends upon the amount of cash it generates from its business. For a description of certain factors that can cause fluctuations in the amount of cash that the Partnership generates from its business, please read “—Risks Inherent in the Partnership’s Business” and “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Factors That Significantly Affect Our Results.” The Partnership may not have sufficient available cash each quarter to continue paying distributions at their current level or at all. If the Partnership reduces its per unit distribution, because of reduced operating cash flow, higher expenses, capital requirements or otherwise, we will have less cash available to pay dividends to our stockholders and would probably be required to reduce the dividend per share of common stock. The amount of cash the Partnership has available for distribution depends primarily upon the Partnership’s cash flow, including cash flow from the release of reserves as well as borrowings, and is not solely a function of profitability, which will be affected by non-cash items. As a result, the Partnership may make cash distributions during periods when it records losses and may not make cash distributions during periods when it records profits.

Once we receive cash from the Partnership and the general partner, our ability to distribute the cash received to our stockholders is limited by a number of factors, including:

- our obligation to satisfy tax obligations associated with previous sales of assets to the Partnership;
- interest expense and principal payments on any indebtedness we incur;
- restrictions on distributions contained in any existing or future debt agreements;
- our general and administrative expenses, including expenses we incur as a result of being a public company as well as other operating expenses;
- expenses of the general partner;
- income taxes;
- reserves we establish in order for us to maintain our 2% general partner interest in the Partnership upon the issuance of additional partnership securities by the Partnership; and
- reserves our board of directors establishes for the proper conduct of our business, to comply with applicable law or any agreement binding on us or our subsidiaries or to provide for future dividends by us.

The actual amount of cash that is available for dividends to our stockholders will depend on numerous factors, many of which are beyond our control.

A reduction in the Partnership's distributions will disproportionately affect the amount of cash distributions to which we are entitled.

Our ownership of the IDRs in the Partnership entitles us to receive specified percentages of the amount of cash distributions made by the Partnership to its limited partners only in the event that the Partnership distributes more than \$0.3881 per unit for such quarter. As a result, the holders of the Partnership's common units have a priority over our IDRs to the extent of cash distributions by the Partnership up to and including \$0.3881 per unit for any quarter.

34

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### Table of Contents

Our IDRs entitle us to receive increasing percentages, up to 48%, of all cash distributed by the Partnership. Because the Partnership's distribution rate is currently above the maximum target cash distribution level on the IDRs, future growth in distributions we receive from the Partnership will not result from an increase in the target cash distribution level associated with the IDRs. Furthermore, a decrease in the amount of distributions by the Partnership to less than \$0.50625 per unit per quarter would reduce the general partner's percentage of the incremental cash distributions above \$0.3881 per common unit per quarter from 48% to 23%. As a result, any such reduction in quarterly cash distributions from the Partnership would have the effect of disproportionately reducing the distributions that we receive from the Partnership based on our IDRs as compared to distributions we receive from the Partnership with respect to our 2% general partner interest and our common units.

If the Partnership's unitholders remove the general partner, we would lose our general partner interest and IDRs in the Partnership and the ability to manage the Partnership.

We currently manage our investment in the Partnership through our ownership interest in the general partner. The Partnership's partnership agreement, however, gives unitholders of the Partnership the right to remove the general partner upon the affirmative vote of holders of 66 % of the Partnership's outstanding units. If the general partner were removed as general partner of the Partnership, it would receive cash or common units in exchange for its 2% general partner interest and the IDRs and would also lose its ability to manage the Partnership. While the cash or common units the general partner would receive are intended under the terms of the Partnership's partnership agreement to fully compensate us in the event such an exchange is required, the value of the investments we make with the cash or the common units may not over time be equivalent to the value of the general partner interest and the IDRs had the general partner retained them.

In addition, if the general partner is removed as general partner of the Partnership, we would face an increased risk of being deemed an investment company. Please read "—If in the future we cease to manage and control the Partnership, we may be deemed to be an investment company under the Investment Company Act of 1940."

The Partnership, without our stockholders' consent, may issue additional common units or other equity securities, which may increase the risk that the Partnership will not have sufficient available cash to maintain or increase its cash distribution level per common unit.

Because the Partnership distributes to its partners most of the cash generated by its operations, it relies primarily upon external financing sources, including debt and equity issuances, to fund its acquisitions and expansion capital expenditures. Accordingly, the Partnership has wide latitude to issue additional common units on the terms and conditions established by its general partner. We receive cash distributions from the Partnership on the general partner interest, IDRs and common units that we own. Because a significant portion of the cash we receive from the Partnership is attributable to our ownership of the IDRs, payment of distributions on additional Partnership common units may increase the risk that the Partnership will be unable to maintain or increase its quarterly cash distribution per unit, which in turn may reduce the amount of distributions we receive attributable to our common units, general partner interest and IDRs and the available cash that we have to pay as dividends to our stockholders.

The general partner, with our consent but without the consent of our stockholders, may limit or modify the incentive distributions we are entitled to receive, which may reduce cash dividends to you.

We own the general partner, which owns the IDRs in the Partnership that entitle us to receive increasing percentages, up to a maximum of 48% of any cash distributed by the Partnership as certain target distribution levels are reached in excess of \$0.3881 per common unit in any quarter. A substantial portion of the cash flow we receive from the Partnership is provided by these IDRs. Because of the high percentage of the Partnership's incremental cash flow that is distributed to the IDRs, certain potential acquisitions might not increase cash available for distribution per Partnership unit. In order to facilitate acquisitions by the Partnership or for other reasons, the board of directors of the

general partner may elect to reduce the IDRs payable to us with our consent. These reductions may be permanent reductions in the IDRs or may be reductions with respect to cash flows from the potential acquisition. If distributions on the IDRs were reduced for the benefit of the Partnership units, the total amount of cash distributions we would receive from the Partnership, and therefore the amount of cash dividends we could pay to our stockholders, would be reduced.

35

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Table of Contents

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

Because our only source of operating cash flow consists of cash distributions from the Partnership, the amount of dividends we are able to pay to our stockholders may fluctuate based on the level of distributions the Partnership makes to its partners, including us. The Partnership may not continue to make quarterly distributions at the 2014 fourth quarter distribution level of \$ 0.81000 per common unit, or may not distribute any other amount, or increase its quarterly distributions in the future. In addition, while we would expect to increase or decrease dividends to our stockholders if the Partnership increases or decreases distributions to us, the timing and amount of such changes in distributions, if any, will not necessarily be comparable to the timing and amount of any changes in dividends made by us. Factors such as reserves established by our board of directors for our estimated general and administrative expenses as well as other operating expenses, reserves to satisfy our debt service requirements, if any, and reserves for future dividends by us may affect the dividends we make to our stockholders. The actual amount of cash that is available for dividends to our stockholders will depend on numerous factors, many of which are beyond our control.

Our cash dividend policy limits our ability to grow.

Because we plan on distributing a substantial amount of our cash flow, our growth may not be as fast as the growth of businesses that reinvest their available cash to expand ongoing operations. In fact, because currently our only cash-generating assets are common units and general partner interests in the Partnership, our growth will be substantially dependent upon the Partnership. If we issue additional shares of common stock or we incur debt, the payment of dividends on those additional shares or interest on that debt could increase the risk that we will be unable to maintain or increase our cash dividend levels.

Our rate of growth may be reduced to the extent we purchase additional units from the Partnership, which will reduce the relative percentage of the cash we receive from the IDRs.

Our business strategy includes, where appropriate, supporting the growth of the Partnership by purchasing the Partnership's units or lending funds or providing other forms of financial support to the Partnership to provide funding for the acquisition of a business or asset or for a growth project. To the extent we purchase common units or securities not entitled to a current distribution from the Partnership, the rate of our distribution growth may be reduced, at least in the short term, as less of our cash distributions will come from our ownership of IDRs, whose distributions increase at a faster rate than those of our other ownership interests.

We have a credit facility that contains various restrictions on our ability to pay dividends to our stockholders, borrow additional funds or capitalize on business opportunities.

We have a credit facility that contains various operating and financial restrictions and covenants. Our ability to comply with these restrictions and covenants may be affected by events beyond our control, including prevailing economic, financial and industry conditions. If we are unable to comply with these restrictions and covenants, any future indebtedness under this credit facility may become immediately due and payable and our lenders' commitments to make further loans to us may terminate. We might not have, or be able to obtain, sufficient funds to make these accelerated payments.

Our credit facility limits our ability to pay dividends to our stockholders during an event of default or if an event of default would result from such dividend. In addition, any future borrowings may:

adversely affect our ability to obtain additional financing for future operations or capital needs;

limit our ability to pursue acquisitions and other business opportunities;

• make our results of operations more susceptible to adverse economic or operating conditions; or

• limit our ability to pay dividends.

Our payment of any principal and interest will reduce our cash available for dividends to our stockholders. In addition, we are able to incur substantial additional indebtedness in the future. If we incur additional debt, the risks associated with our leverage would increase. For more information regarding our credit facility, please see Note 10 of the “Consolidated Financial Statements” beginning on page F-1 in this Form 10-K.

Table of Contents

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

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

The Partnership's practice of distributing all of its available cash may limit its ability to grow, which could impact distributions to us and the available cash that we have to dividend to our stockholders.

Because currently our only cash-generating assets are common units and general partner interests in the Partnership, including the IDRs, our growth will be dependent upon the Partnership's ability to increase its quarterly cash distributions. The Partnership has historically distributed to its partners most of the cash generated by its operations. As a result, it relies primarily upon external financing sources, including debt and equity issuances, to fund its acquisitions and expansion capital expenditures. Accordingly, to the extent the Partnership is unable to finance growth externally; its ability to grow will be impaired because it distributes substantially all of its available cash. Also, if the Partnership incurs additional indebtedness to finance its growth, the increased interest expense associated with such indebtedness may reduce the amount of available cash that the Partnership distributes to us, which in turn may reduce the amount of available cash that we can distribute to our stockholders. In addition, to the extent the Partnership issues additional common units in connection with any acquisitions or growth capital expenditures, the payment of distributions on those additional common units may increase the risk that the Partnership will be unable to maintain or increase its per unit distribution level, which in turn may impact the cash available for dividends to our stockholders.

Restrictions in the Partnership's Senior Secured Revolving Credit Facility (the "TRP Revolver") and indentures could limit its ability to make distributions to us.

The TRP Revolver and indentures contain covenants limiting its ability to incur indebtedness, grant liens, engage in transactions with affiliates and make distributions. The TRP Revolver also contains covenants requiring the Partnership to maintain certain financial ratios. The Partnership is prohibited from making any distribution to unitholders if such distribution would cause an event of default or otherwise violate a covenant under the TRP Revolver or the indentures, which in turn may impact the cash available for dividends to our stockholders.

If in the future we cease to manage and control the Partnership, we may be deemed to be an investment company under the Investment Company Act of 1940.

If we cease to manage and control the Partnership and are deemed to be an investment company under the Investment Company Act of 1940, we would either have to register as an investment company under the Investment Company Act of 1940, obtain exemptive relief from the SEC or modify our organizational structure or our contractual rights to fall outside the definition of an investment company. Registering as an investment company could, among other things, materially limit our ability to engage in transactions with affiliates, including the purchase and sale of certain securities or other property to or from our affiliates, restrict our ability to borrow funds or engage in other transactions involving leverage and require us to add additional directors who are independent of us and our affiliates, and adversely affect the price of our common stock.

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

Our success is dependent upon the efforts of the named executive officers. Our named executive officers are responsible for executing our and the Partnership's business strategies and, when appropriate to our primary business objective, facilitating the Partnership's growth through various forms of financial support provided by us, including, but not limited to, modifying the Partnership's IDRs, exercising the Partnership's IDR reset provision contained in its

partnership agreement, making loans, making capital contributions in exchange for yielding or non-yielding equity interests or providing other financial support to the Partnership. There is substantial competition for qualified personnel in the midstream natural gas industry. We may not be able to retain our existing named executive officers or fill new positions or vacancies created by expansion or turnover. We have not entered into employment agreements with any of our named executive officers. In addition, we do not maintain “key man” life insurance on the lives of any of our named executive officers. A loss of one or more of our named executive officers could harm our and the Partnership’s business and prevent us from implementing our and the Partnership’s business strategies.

Table of Contents

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

Effective internal controls are necessary for us to provide timely and reliable financial reports and effectively prevent fraud. If we cannot provide timely and reliable financial reports or prevent fraud, our reputation and operating results would be harmed. We continue to enhance our internal controls and financial reporting capabilities. These enhancements require a significant commitment of resources, personnel and the development and maintenance of formalized internal reporting procedures to ensure the reliability of our financial reporting. Our efforts to update and maintain our internal controls may not be successful, and we may be unable to maintain adequate controls over our financial processes and reporting in the future, including future compliance with the obligations under Section 404 of the Sarbanes-Oxley Act of 2002. Any failure to maintain effective controls or difficulties encountered in the effective improvement of our internal controls could prevent us from timely and reliably reporting our financial results and may harm our operating results. Ineffective internal controls could also cause investors to lose confidence in our reported financial information. In addition, the Financial Accounting Standards Board or the SEC could enact new accounting standards that might impact how we or the Partnership are required to record revenues, expenses, assets and liabilities. Any significant change in accounting standards or disclosure requirements could have a material effect on our business, results of operations, financial condition and ability to comply with our and the Partnership's debt obligations.

An increase in interest rates may cause the market price of our common stock to decline.

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

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

We or our stockholders may sell shares of common stock in subsequent public offerings. We may also issue additional shares of common stock or convertible securities. As of December 31, 2014, we have 42,143,463 outstanding shares of common stock. Certain of our existing stockholders, including our executive officers, and certain of our directors are party to a registration rights agreement with us which requires us to affect the registration of their shares in certain circumstances no earlier than the expiration of the lock-up period contained in the underwriting agreement of our initial public offering.

We cannot predict the size of future issuances of our common stock or the effect, if any, that future issuances and sales of shares of our common stock will have on the market price of our common stock. Sales of substantial amounts of our common stock (including shares issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices of our common stock.

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

Our amended and restated certificate of incorporation authorizes our board of directors to issue preferred stock without stockholder approval. If our board of directors elects to issue preferred stock, it could be more difficult for a

third-party to acquire us. In addition, some provisions of our amended and restated certificate of incorporation and amended and restated bylaws could make it more difficult for a third-party to acquire control of us, even if the change of control would be beneficial to our stockholders, including provisions which require:

• a classified board of directors, so that only approximately one-third of our directors are elected each year;

• limitations on the removal of directors; and

38

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## Table of Contents

limitations on the ability of our stockholders to call special meetings and establish advance notice provisions for stockholder proposals and nominations for elections to the board of directors to be acted upon at meetings of stockholders.

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

The duties of our officers and directors may conflict with those owed to the Partnership and these officers and directors may face conflicts of interest in the allocation of administrative time among our business and the Partnership’s business.

Substantially all of our officers and certain members of our board of directors are officers and/or directors of the general partner and, as a result, have separate duties that govern their management of the Partnership’s business. These officers and directors may encounter situations in which their obligations to us, on the one hand, and the Partnership, on the other hand, are in conflict. The resolution of these conflicts may not always be in our best interest or that of our stockholders.

In addition, our officers who also serve as officers of the general partner may face conflicts in allocating their time spent on our behalf and on behalf of the Partnership. These time allocations may adversely affect our or the Partnership’s results of operations, cash flows and financial condition. For a discussion of our officers and directors that will serve in the same capacity for the general partner and the amount of time we expect them to devote to our business, please read “Management.”

## Risks Inherent in the Partnership’s Business

Because we are directly dependent on the distributions we receive from the Partnership, risks to the Partnership’s operations are also risks to us. We have set forth below risks to the Partnership’s business and operations, the occurrence of which could negatively impact the Partnership’s financial performance and decrease the amount of cash it is able to distribute to us.

The Partnership has a substantial amount of indebtedness which may adversely affect its financial position.

The Partnership has a substantial amount of indebtedness. As of December 31, 2014, the Partnership had \$2,808.6 million outstanding under its senior unsecured notes, excluding \$25.2 million in unamortized discounts. The Partnership also had \$182.8 million outstanding under its accounts receivable securitization facility (the “Securitization Facility”). In addition, the Partnership had \$0 million of borrowings outstanding, \$41.7 million of letters of credit outstanding and \$1,155.9 million of additional borrowing capacity available under the TRP Revolver. The \$1.2 billion TRP Revolver allows it to request increases in commitments up to an additional \$300 million. For the years ended December 31, 2014, 2013 and 2012, the Partnership’s consolidated interest expense was \$143.8 million, \$131.0 million and \$116.8 million, respectively. In addition, the Partnership expects that its indebtedness will increase following the closing of the Atlas Mergers. For example, as of January 31, 2015, on a pro forma as adjusted basis to give effect to certain Atlas Merger-related items set forth under “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources,” the Partnership would have had \$867.7 million of borrowings outstanding, \$41.7 million of letters of credit outstanding and \$568.5 million of additional borrowing capacity available under the TRP Revolver.

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

- its 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;

Table of Contents

satisfying its 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;

the Partnership 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;

the Partnership's debt level will make it more vulnerable to competitive pressures or a downturn in its business or the economy generally; and

the Partnership's debt level may limit flexibility in planning for, or responding to, changing business and economic conditions.

The Partnership's ability to service its debt will depend upon, among other things, its 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 its control. If the Partnership's operating results are not sufficient to service its current or future indebtedness, it 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 be adversely affect our ability to make cash distributions. The Partnership may not be able to affect any of these actions on satisfactory terms, or at all.

Increases in interest rates could adversely affect the Partnership's business.

The Partnership has significant exposure to increases in interest rates. As of December 31, 2014, its total indebtedness was \$2,991.4 million, excluding \$25.2 million in unamortized discounts, of which \$2,808.6 million was at fixed interest rates and \$182.8 million was at variable interest rates. A one percentage point increase in the interest rate on the Partnership's variable interest rate debt would have increased its consolidated annual interest expense by approximately \$1.8 million. As a result of this amount of variable interest rate debt, the Partnership's financial condition could be adversely affected by increases in interest rates.

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

The Partnership may be able to incur substantial additional indebtedness in the future. As of December 31, 2014, the Partnership had \$182.8 million of borrowings outstanding under its Securitization Facility. In addition, the Partnership had \$0 million of borrowings outstanding, \$44.1 million of letters of credit outstanding and \$1,155.9 million of additional borrowing capacity available under the TRP Revolver. In addition, the Partnership expects that its indebtedness will increase following the closing of the Atlas Mergers. For example, as of January 31, 2015, on a pro forma as adjusted basis to give effect to certain Atlas Merger-related items set forth under "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources," the Partnership would have had \$867.7 million of borrowings outstanding, \$41.7 million of letters of credit outstanding and \$526.8 million of additional borrowing capacity available under the TRP Revolver. The Partnership may be able to increase the borrowing capacity under the TRP Revolver by an additional \$300 million if the Partnership requests and is 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 the Partnership incurs additional debt, the risks associated with its substantial leverage would increase.

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

The credit agreement governing the TRP Revolver, the agreements governing the Securitization Facility and the indentures governing the Partnership's senior notes contain, and any future indebtedness the Partnership incurs will likely contain, a number of restrictive covenants that impose significant operating and financial restrictions, including restrictions on its ability to engage in acts that may be in its best long-term interests. These agreements include covenants that, among other things, restrict the Partnership's ability to:

• incur or guarantee additional indebtedness or issue preferred stock;

40

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Table of Contents

pay distributions on its equity securities or redeem, repurchase or retire its equity securities or subordinated indebtedness;

make investments and certain acquisitions;

create restrictions on the payment of distributions to its equity holders;

sell or transfer assets, including equity securities of its 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 it.

In addition, the TRP Revolver requires the Partnership to satisfy and maintain specified financial ratios and other financial condition tests. The Partnership's ability to meet those financial ratios and tests can be affected by events beyond its control, and we cannot assure you that the Partnership 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 the Partnership is 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 the Partnership is 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. The Partnership has pledged substantially all of its assets as collateral under the TRP Revolver and the accounts receivables of Targa Receivables LLC under the Securitization Facility. If the indebtedness under the TRP Revolver, the indentures, or the Securitization Facility is accelerated, we cannot assure you that the Partnership 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 the Partnership's ability to finance future operations or capital needs or to engage in other business activities.

The Partnership's 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 its results of operations and financial condition.

The Partnership's 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. The Partnership's future cash flow may be materially adversely affected if it experiences significant, prolonged price deterioration. The markets and prices for natural gas and NGLs depend upon factors beyond the Partnership's 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 the Partnership's primary markets;

the economic conditions of the Partnership's customers;

- the level of domestic crude oil and natural gas production and consumption;

41

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Table of Contents

- 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.

The Partnership's primary natural gas gathering and processing arrangements that expose it to commodity price risk are its percent-of-proceeds arrangements. For the years ended December 31, 2014 and 2013, the Partnership's percent-of-proceeds arrangements accounted for approximately 51% and 48%, respectively, of its gathered natural gas volume. Under these arrangements, the Partnership generally processes natural gas from producers and remits 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 the Partnership's processing facilities. In some percent-of-proceeds arrangements, the Partnership remits 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, the Partnership's revenues and cash flows increase or decrease, whichever is applicable, as the prices of natural gas, NGLs and crude oil fluctuates. Please see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

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

The Partnership's gathering systems are connected to crude oil and natural gas wells from which production will naturally decline over time, which means that the cash flows associated with these sources of natural gas and crude oil will likely also decline over time. The Partnership's logistics assets are similarly impacted by declines in NGL supplies in the regions in which it operates as well as other regions from which it sources NGLs. To maintain or increase throughput levels on the Partnership's gathering systems and the utilization rate at its processing plants and its treating and fractionation facilities, the Partnership 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 the Partnership relies, as a result of depressed commodity prices or otherwise, could result in a decline in the volume of natural gas or crude oil that it processes, NGL products delivered to its fractionation facilities or crude oil that the Partnership gathers. The Partnership's 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 its gathering systems and, in part, on the level of successful drilling and production in other areas from which it sources NGL and crude oil supplies. The Partnership has no control over the level of such activity in the areas of its operations, the amount of reserves associated with the wells or the rate at which production from a well will decline. In addition, the Partnership has no control over producers or their drilling or production decisions, which are affected by, among other things, prevailing and projected energy prices, demand for hydrocarbons, the level of reserves, geological considerations, governmental regulations, the availability of drilling rigs, other production and development costs and the availability and cost of capital.

Fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new oil and natural gas reserves. Drilling and production activity generally decreases as crude oil and natural gas

prices decrease. Prices of crude oil and natural gas have been historically volatile, and we expect this volatility to continue. Consequently, even if new natural gas or crude oil reserves are discovered in areas served by the Partnership's 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 the Partnership operates may prevent it 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 its facilities and reduced utilization of its gathering, treating, processing and fractionation assets.

## Table of Contents

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

The Partnership's ability to grow depends, in part, on its ability to make acquisitions or develop growth projects that result in an increase in cash generated from operations per unit. The Partnership is unable to acquire businesses from us in order to grow because our only assets are the interests in the Partnership that we own. As a result, the Partnership will need to focus on third-party acquisitions and organic growth. If the Partnership is unable to make accretive acquisitions or develop accretive growth projects because it is (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 the Partnership's 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 the Partnership's 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 the Partnership may experience unanticipated delays in realizing the benefits of an acquisition or growth project. If the Partnership consummates 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 the Partnership will consider in evaluating future acquisitions or growth projects.

The Partnership's acquisition and growth strategy is based, in part, on its 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 the Partnership's opportunities for future acquisitions or growth projects and could adversely affect its operations and cash flows available for distribution to its unitholders.

### Table of Contents

Acquisitions may significantly increase the Partnership's size and diversify the geographic areas in which it operates and growth projects may increase its concentration in a line of business or geographic region. The Partnership may not achieve the desired effect from any future acquisitions or growth projects.

The Partnership's 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 its results of operations and financial condition.

The construction of additions or modifications to the Partnership's existing systems and the construction of new midstream assets involve numerous regulatory, environmental, political and legal uncertainties beyond its control and may require the expenditure of significant amounts of capital. If the Partnership undertakes these projects, they may not be completed on schedule or at the budgeted cost or at all. Moreover, the Partnership's revenues may not increase immediately upon the expenditure of funds on a particular project. For instance, if the Partnership builds a new fractionation facility or gas processing plant, the construction may occur over an extended period of time and the Partnership will not receive any material increases in revenues until the project is completed. Moreover, the Partnership may construct facilities to capture anticipated future growth in production in a region in which such growth does not materialize. Since the Partnership is not engaged in the exploration for and development of natural gas and oil reserves, it does not possess reserve expertise and it often does not have access to third-party estimates of potential reserves in an area prior to constructing facilities in such area. To the extent the Partnership relies on estimates of future production in any decision to construct additions to its 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 the Partnership's expected investment return, which could adversely affect its results of operations and financial condition. In addition, the construction of additions to the Partnership's existing gathering and transportation assets may require it to obtain new rights-of-way prior to constructing new pipelines. The Partnership may be unable to obtain such rights-of-way to connect new natural gas supplies to its existing gathering lines or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive for the Partnership 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, the Partnership's cash flows could be adversely affected.

The Partnership's acquisition and growth strategy requires access to new capital. Tightened capital markets or increased competition for investment opportunities could impair the Partnership's ability to grow through acquisitions or growth projects.

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

In addition, the Partnership is experiencing increased competition for the types of assets it contemplates purchasing or developing. Current economic conditions and competition for asset purchases and development opportunities could limit its ability to fully execute its 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 the Partnership operates can significantly decrease the total volume of propane it sells. Lack of consumer demand for propane may also adversely affect the retailers with which the Partnership transacts its wholesale propane marketing operations, exposing the Partnership to retailers' inability to satisfy their contractual obligations to the Partnership.

Table of Contents

If the Partnership fails to balance its purchases of natural gas and its sales of residue gas and NGLs, its exposure to commodity price risk will increase.

The Partnership may not be successful in balancing its purchases of natural gas and its sales of residue gas and NGLs. In addition, a producer could fail to deliver promised volumes to the Partnership 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 the Partnership's purchases and sales. If the Partnership's purchases and sales are not balanced, it will face increased exposure to commodity price risks and could have increased volatility in its operating income.

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

The Partnership has entered into derivative transactions related to only a portion of its equity volumes. As a result, it will continue to have direct commodity price risk to the unhedged portion. The Partnership's actual future volumes may be significantly higher or lower than it estimated at the time it entered into the derivative transactions for that period. If the actual amount is higher than the Partnership estimated, it will have greater commodity price risk than it intended. If the actual amount is lower than the amount that is subject to its derivative financial instruments, the Partnership might be forced to satisfy all or a portion of its derivative transactions without the benefit of the cash flow from its sale of the underlying physical commodity. The percentages of the Partnership's expected equity volumes that are covered by its hedges decrease over time. To the extent the Partnership hedges its commodity price risk, it may forego the benefits it would otherwise experience if commodity prices were to change in its favor. The derivative instruments the Partnership utilizes 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 it realizes in its operations. These pricing differentials may be substantial and could materially impact the prices the Partnership ultimately realizes. In addition, market and economic conditions may adversely affect the Partnership's hedge counterparties' ability to meet their obligations. Given volatility in the financial and commodity markets, the Partnership may experience defaults by its hedge counterparties in the future. As a result of these and other factors, the Partnership's hedging activities may not be as effective as it intended in reducing the variability of its cash flows, and in certain circumstances may actually increase the variability of its cash flows. Please see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk."

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

The Partnership depends upon third-party pipelines, storage and other facilities that provide delivery options to and from its gathering and processing facilities. Since the Partnership does not own or operate these pipelines or other facilities, their continuing operation in their current manner is not within its 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 the Partnership's ability to utilize them, its revenues could be adversely affected.

The Partnership's industry is highly competitive, and increased competitive pressure could adversely affect its business and operating results.

The Partnership competes with similar enterprises in its respective areas of operation. Some of the Partnership's competitors are large oil, natural gas and NGL companies that have greater financial resources and access to supplies of natural gas and NGLs than it does. Some of these competitors may expand or construct gathering, processing, storage, terminaling and transportation systems that would create additional competition for the services the Partnership provides to its customers. In addition, customers who are significant producers of natural gas may develop

their own gathering, processing, storage, terminaling and transportation systems in lieu of using those operated by the Partnership. The Partnership's ability to renew or replace existing contracts with its customers at rates sufficient to maintain current revenues and cash flows could be adversely affected by the activities of its competitors and its customers. All of these competitive pressures could have a material adverse effect on the Partnership's business, results of operations and financial condition.

45

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### Table of Contents

The Partnership typically does not obtain independent evaluations of natural gas or crude oil reserves dedicated to its gathering pipeline systems; therefore, supply volumes on its systems in the future could be less than it anticipates.

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

The NGL products the Partnership produces 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 the Partnership handles or reduce the fees it charges for its services. Also, increased supply of NGL products could reduce the value of NGLs handled by the Partnership and reduce the margins realized. The Partnership's 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 the Partnership's 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 the Partnership accesses for any of the reasons stated above could adversely affect both demand for the services it provides and NGL prices, which could negatively impact its results of operations and financial condition.

### Table of Contents

The tax treatment of the Partnership depends on its status as a partnership for U.S. federal income tax purposes as well as its not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service (“IRS”) were to treat the Partnership as a corporation for federal income tax purposes or the Partnership becomes subject to a material amount of entity-level taxation for state tax purposes, then its cash available for distribution to its unitholders, including us, would be substantially reduced.

We currently own an approximate 10.9% limited partner interest, a 2% general partner interest and the IDRs in the Partnership. The anticipated after-tax economic benefit of our investment in the Partnership depends largely on its being treated as a partnership for federal income tax purposes. A publicly traded partnership such as the Partnership may be treated as a corporation for federal income tax purposes unless it satisfies a “qualifying income” requirement. Based on the Partnership’s current operations we believe that the Partnership satisfies the qualifying income requirement and will be treated as a partnership. Failing to meet the qualifying income requirement or a change in current law could cause the Partnership to be treated as a corporation for federal income tax purposes or otherwise subject the Partnership to taxation as an entity. The Partnership has not requested and does not plan to request a ruling from the IRS with respect to its treatment as a partnership for federal income tax purposes.

If the Partnership were treated as a corporation for federal income tax purposes, it would pay federal income tax on its taxable income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state income tax at varying rates. Distributions to the Partnership’s unitholders, including us, would generally be taxed again as corporate distributions and no income, gains, losses or deductions would flow through to the Partnership’s unitholders, including us. If such tax was imposed upon the Partnership as a corporation, its cash available for distribution would be substantially reduced. Therefore, treatment of the Partnership as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to the Partnership’s unitholders, including us, and would likely cause a substantial reduction in the value of our investment in the Partnership.

At the state level, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income and franchise taxes and other forms of taxation. For example, the Partnership is required to pay Texas franchise tax at a maximum effective rate of 0.7% of its gross income apportioned to Texas in the prior year. Imposition of any similar tax on the Partnership by additional states would reduce the cash available for distribution to Partnership unitholders, including us.

Current law may change so as to cause the Partnership to be treated as a corporation for federal income tax purposes or otherwise subject the Partnership to entity-level taxation for state or local income tax purposes. The present U.S. federal income tax treatment of publicly traded partnerships, including the Partnership, or an investment in the Partnership’s common units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. For example, from time to time, members of Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships. One such legislative proposal would eliminate the qualifying income exception to the treatment of all publicly traded partnerships as corporations upon which the Partnership relies for its treatment as a partnership for U.S. federal income tax purposes. We are unable to predict whether any of these changes or other proposals will be reintroduced or will ultimately be enacted. Any such changes could negatively impact the value of our investment in the Partnership’s common units.

The Partnership’s partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects it to taxation as a corporation or otherwise subjects it to entity-level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on the Partnership.

The Partnership does not own most of the land on which its pipelines, terminals and compression facilities are located, which could disrupt its operations.

The Partnership does not own most of the land on which its pipelines, terminals and compression facilities are located, and the Partnership is therefore subject to the possibility of more onerous terms and/or increased costs to retain necessary land use if it does not have valid rights-of-way or leases or if such rights-of-way or leases lapse or terminate. The Partnership sometimes obtains the rights to land owned by third parties and governmental agencies for a specific period of time. The Partnership's loss of these rights, through its inability to renew right-of-way contracts or leases, or otherwise, could cause it to cease operations on the affected land, increase costs related to continuing operations elsewhere and reduce its revenue.

## Table of Contents

The Partnership may be unable to cause its majority-owned joint ventures to take or not to take certain actions unless some or all of its joint venture participants agree.

The Partnership participates 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, the Partnership may be unable to cause any of its joint ventures to take or not take certain actions, even though taking or preventing those actions may be in the best interests of the Partnership 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 the Partnership partnering with different or additional parties.

Weather may limit the Partnership's ability to operate its business and could adversely affect its operating results.

The weather in the areas in which the Partnership operates can cause disruptions and in some cases suspension of its operations. For example, unseasonably wet weather, extended periods of below freezing weather, or hurricanes may cause disruptions or suspensions of the Partnership's operations, which could adversely affect its operating results. 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 the Partnership's operations.

The Partnership's 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 it is not fully insured, if the Partnership fails to recover all anticipated insurance proceeds for significant accidents or events for which it is insured, or if the Partnership fails to rebuild facilities damaged by such accidents or events, its operations and financial results could be adversely affected.

The Partnership's 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 the Partnership's negligence or any of its 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.



### Table of Contents

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 the Partnership's related operations. A natural disaster or other hazard affecting the areas in which the Partnership operates could have a material adverse effect on its 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 the Partnership's 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. The Partnership is not fully insured against all risks inherent to its business. Additionally, while the Partnership is insured for pollution resulting from environmental accidents that occur on a sudden and accidental basis, it 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 the Partnership fails to recover all anticipated insurance proceeds for significant accidents or events for which it is insured, or if the Partnership fails to rebuild facilities damaged by such accidents or events, its operations and financial condition could be adversely affected. In addition, the Partnership may not be able to maintain or obtain insurance of the type and amount it desires at reasonable rates. As a result of market conditions, premiums and deductibles for certain of the Partnership's 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 in September 2008. As a result, the Partnership experienced further increases in deductibles and premiums, and further reductions in coverage and limits, with some coverage unavailable at any cost.

The Partnership 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. The Partnership currently estimates an average annual cost of \$2.5 million between 2015 and 2017 to implement pipeline integrity management program testing along certain segments of its 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, the Partnership 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. The Partnership will continue its pipeline

integrity testing programs to assess and maintain the integrity of its pipelines. The results of these tests could cause the Partnership to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of its pipelines.

## Table of Contents

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 the Partnership 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 the Partnership’s exposure to commodity price movements.

The Partnership sells 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. The Partnership attempts 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 it to volume imbalances which, in conjunction with movements in commodity prices, could materially impact its income from operations and cash flow.

The Partnership requires a significant amount of cash to service its indebtedness. The Partnership’s ability to generate cash depends on many factors beyond its control.

The Partnership’s ability to make payments on and to refinance its indebtedness and to fund planned capital expenditures depends on its 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 the Partnership’s control. We cannot assure you that the Partnership will generate sufficient cash flow from operations, that future borrowings will be available to it under the TRP Revolver, that it will be able to sell its accounts receivables or make borrowings under its Securitization Facility, or otherwise in an amount sufficient to enable it to pay its indebtedness or to fund its other liquidity needs. The Partnership may need to refinance all or a portion of its indebtedness at or before maturity. We cannot assure you that the Partnership will be able to refinance any of its 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 the Partnership to incur significant costs and liabilities.

The Partnership’s 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 its 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 its 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.

50

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### Table of Contents

There is inherent risk of incurring environmental costs and liabilities in connection with the Partnership's operations due to its handling of natural gas, NGLs, crude oil and other petroleum products because of air emissions and product-related discharges arising out of its operations, and as a result of historical industry operations and waste disposal practices. For example, an accidental release from one of the Partnership's facilities could subject it 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 the Partnership's 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 natural gas wells for any extended period of time could increase the Partnership's 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 the Partnership has a business relationship, which could have a material adverse effect on its 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 the Partnership's revenues by decreasing the volumes of natural gas, NGLs or crude oil through its facilities and reducing the utilization of its assets.

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 certain aspects of the process, including the EPA, which plans to propose effluent limit guidelines in the first half of 2015 for wastewater from shale gas extraction operations before being discharged to a treatment plant, and the Bureau of Land Management, which proposed regulations applicable to hydraulic fracturing conducted on federal and Indian oil and gas leases and is expected to issue a final rule in the first half of 2015. 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 Governor Andrew Cuomo of the State of New York announced in December 2014 with regard to fracturing activities in New York. 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. For example, in November 2014, residents in Denton, Texas, approved a city ordinance prohibiting hydraulic fracturing within the city limits effective December 2, 2014 but the ordinance is subject to challenge. If new or more stringent federal, state or local legal restrictions or prohibitions relating to the hydraulic fracturing process are adopted in areas where the Partnership's 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 the Partnership's gathering, processing and fractionation services. 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, with the EPA planning to issue a draft of its final report on hydraulic fracturing in the first half of 2015. These studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing, which events could delay or curtail production of natural gas by exploration and production operators, some of which are the Partnership's customers, and thus reduce demand for the Partnership's midstream services.

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

With the exception of the Partnership's interest in VGS, its operations are generally exempt from FERC regulation under the NGA, but FERC regulation still affects its non-FERC jurisdictional businesses and the markets for products derived from these businesses, including certain FERC reporting and posting requirements in a given year. The Partnership believes 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 the Partnership's gathering facilities are subject to change based on future determinations by FERC, the courts or Congress. 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 the Partnership's gathering facilities and transportation pipelines may be subject to change based on future determinations by FERC, the courts or Congress.

## Table of Contents

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, the Partnership 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 the Partnership's 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 the Partnership operates a significant portion of its 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 the Partnership's costs of doing business on the Fort Berthold Indian Reservation and may have an adverse impact on its ability to effectively transport products within the Fort Berthold Indian Reservation or to conduct its operations on such lands.

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

Should the Partnership fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, it 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 the Partnership's systems other than VGS have not been regulated by FERC as a natural gas company under the NGA, FERC has adopted regulations that may subject certain of its 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 the Partnership to civil penalty liability. For more information regarding regulation of the Partnership's operations, see "Item 1. Business—Regulation of Operations."

## Table of Contents

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 the Partnership provides.

In December 2009, the EPA published its findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA has adopted rules under the Clean Air Act that, among other things, establish PSD construction and Title V operating permit reviews for GHG emissions from certain large stationary sources that are also potential major sources of certain principal, or criteria, pollutant emissions, which reviews could require securing PSD permits at covered facilities emitting GHGs and meeting "best available control technology" standards for those GHG emissions. 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. On December 9, 2014, the EPA published a proposed rule that would expand the petroleum and natural gas system sources for which annual GHG emissions reporting is currently required to include GHG emissions reporting beginning in the 2016 reporting year for 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, pursuant to President Obama's Strategy to Reduce Methane Emissions, the Obama Administration announced on January 14, 2015, a goal to reduce methane emissions from the oil and gas sector by up to 45 percent from 2012 levels by 2025 and that, in furtherance of that goal, EPA will propose in the summer of 2015 and finalize in 2016 new regulations that will set methane emission standards for oil and gas production and natural gas processing and transmission facilities. 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 the Partnership's 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 the Partnership gathers and processes or fractionates. 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 the Partnership provides.

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.

The 2011 Pipeline Safety Act is the most recent federal legislation to amend the NGPSA and HLPESA 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 the Partnership's incurring increased operating costs that could have a material adverse effect on the Partnership's results of operations or financial position. For example, PHMSA and one or more state regulators, including the RRC, have recently 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. These actions by PHMSA are currently subject to judicial and administrative challenges by one or more midstream operators; however, to the extent that such challenges are unsuccessful, 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 the Partnership's ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with its 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 the Partnership, 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.

### Table of Contents

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 the Partnership, 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 the Partnership qualifies for the end-user exception from the mandatory clearing requirements for swaps entered to hedge its 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 the Partnership uses 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 the Partnership for capital expenditures, therefore reducing its 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 the Partnership is uncertain at this time.

The Dodd-Frank Act also may require the counterparties to the Partnership's 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 the Partnership's 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 the Partnership encounters, reduce its ability to monetize or restructure its existing derivative contracts or increase its exposure to less creditworthy counterparties. If the Partnership reduces its use of derivatives as a result of the Dodd-Frank Act and regulations implementing the Dodd-Frank Act, its results of operations may become more volatile and its cash flows may be less predictable, which could adversely affect its 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. The Partnership's 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 the Partnership, its financial condition and its results of operations.

The Partnership's interstate common carrier liquids pipeline is 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 the Partnership maintain tariffs on file with FERC for each of these pipelines. Those tariffs set forth the rates the Partnership charges 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 the Partnership's subsidiaries.

Terrorist attacks and the threat of terrorist attacks have resulted in increased costs to the Partnership's business. Continued hostilities in the Middle East or other sustained military campaigns may adversely impact the Partnership's 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 the Partnership's industry in general and on the Partnership in particular is not known at this time. However, resulting regulatory requirements and/or related business decisions associated with security are likely to increase the Partnership's costs.

## Table of Contents

Increased security measures taken by the Partnership as a precaution against possible terrorist attacks have resulted in increased costs to its business. Uncertainty surrounding continued hostilities in the Middle East or other sustained military campaigns may affect the Partnership's operations in unpredictable ways, including disruptions of crude oil supplies and markets for its 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 the Partnership to obtain. Moreover, the insurance that may be available to the Partnership may be significantly more expensive than its 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 the Partnership's ability to raise capital.

## Risks Related to the Atlas Mergers

The Atlas Mergers are subject to conditions, including certain conditions that may not be satisfied on a timely basis, if at all. Failure to complete the Atlas Mergers, or significant delays in completing the Atlas Mergers, could negatively affect our future business and financial results.

The completion of the Atlas Mergers is subject to a number of conditions, and each of the Atlas Mergers and the Spin-Off is contingent on one another. The completion of the Atlas Mergers is not assured and is subject to risks, including the risk that approval of Targa's stock issuance by Targa stockholders in connection with the ATLS Merger or the approval of the Atlas Mergers by the unitholders of APL and ATLS, as applicable, or by governmental agencies is not obtained or that other closing conditions are not satisfied. If the Atlas Mergers are not completed, or if there are significant delays in completing the Atlas Mergers, our future business and financial results could be negatively affected, and each of the parties involved will be subject to several risks, including the following:

- the parties may be liable for damages to one another under the terms and conditions of the Merger Agreements;
- there may be negative reactions from the financial markets due to the fact that current prices may reflect a market assumption that the Atlas Mergers will be completed; and
- the attention of our management and Atlas management will have been diverted to the Atlas Mergers rather than our own operations and pursuit of other opportunities that could have been beneficial to our business.

We and Atlas may have difficulty attracting, motivating and retaining employees in light of the Atlas Mergers.

The success of the combined entity after the Atlas Mergers will depend in part upon the ability of Targa and Atlas to retain their respective key employees. Key employees may depart either before or after the Atlas Mergers because of issues relating to the uncertainty and difficulty of integration or a desire not to remain following the Atlas Mergers. Accordingly, no assurance can be given that the combined entity will be able to retain key employees to the same extent as in the past.

We and Atlas are subject to business uncertainties and contractual restrictions while the Atlas Mergers are pending, which could adversely affect each party's business and operations.

In connection with the Atlas Mergers, it is possible that some customers, suppliers and other persons with whom we or Atlas have business relationships may delay or defer certain business decisions or, might decide to seek to terminate, change or renegotiate their relationship with us or Atlas as a result of the Atlas Mergers, which could negatively affect the respective revenues, earnings and cash available for distribution of us and Atlas, regardless of whether the Atlas Mergers are completed.

Under the terms of the Merger Agreements, each of us and Atlas is subject to certain restrictions on the conduct of its business prior to completing the Atlas Mergers, which may adversely affect our and Atlas' ability to execute certain of our and its business strategies. Such limitations could negatively affect each party's businesses and operations prior to the completion of the Atlas Mergers. Furthermore, the process of planning to integrate the businesses and organizations for the post-merger period can divert management attention and resources and could ultimately have an adverse effect on each party.

Table of Contents

We and Atlas will incur substantial transaction-related costs in connection with the Atlas Mergers.

We and Atlas expect to incur substantial expenses in connection with completing the Atlas Mergers and integrating the businesses, operations, networks, systems, technologies, policies and procedures of Atlas and us. There are a large number of systems that must be integrated, including billing, management information, purchasing, accounting and finance, sales, payroll and benefits, fixed assets, lease administration and regulatory compliance, and there are a number of factors beyond our and Atlas' control that could affect the total amount or the timing of integration expenses. Many of the expenses that will be incurred, by their nature, are difficult to estimate accurately at the present time. Due to these factors, the transaction and integration expenses associated with the Atlas Mergers could, particularly in the near term, exceed any savings that the combined entity might otherwise realize from the elimination of duplicative expenses and the realization of economies of scale related to the integration of the businesses following the completion of the Atlas Mergers.

Failure to successfully combine our business with the business of Atlas in the expected time frame may adversely affect the future results of the combined entity, and, consequently, our ability to make payments on the notes.

The success of the Atlas Mergers will depend, in part, on our ability to realize the anticipated benefits and synergies from combining our business with the business of Atlas. To realize these anticipated benefits, the businesses must be successfully integrated. If the combined entity is not able to achieve these objectives, or is not able to achieve these objectives on a timely basis, the anticipated benefits of the Atlas Mergers may not be realized fully or at all. In addition, the actual integration may result in additional and unforeseen expenses, which could reduce the anticipated benefits of the Atlas Mergers.

Any acquisitions that we complete, including the Atlas Mergers, are subject to substantial risks.

Any acquisition, including the Atlas Mergers, involves potential risks, including, among other things:

- the validity of our assumptions about, among other things, revenues and costs, including synergies;
- an inability to integrate successfully the businesses we acquire;
- a decrease in our liquidity by using a significant portion of our available cash or borrowing capacity to finance acquisitions;
- a significant increase in our interest expense or financial leverage if we incur additional debt to finance acquisitions;
- the assumption of environmental and other unknown liabilities, losses or costs for which we are not indemnified or for which our indemnity is inadequate;
- the diversion of management's attention from other business concerns;
- an inability to hire, train or retain qualified personnel to manage and operate our growing business and assets;
- the incurrence of other significant charges, such as impairment of goodwill or other intangible assets, asset devaluation or restructuring charges;
- a failure to attain or maintain compliance with environmental and other governmental regulations;
- unforeseen difficulties encountered in operating in new geographic areas; and

·customer or key employee losses at the acquired businesses.

Failure to complete the Atlas Mergers could negatively affect our future business and financial results.

56

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Table of Contents

The Atlas Mergers may be completed on different terms from those contained in the Merger Agreements.

Prior to the completion of the Atlas Mergers, we and Atlas may, by mutual agreement, amend or alter the terms of the Merger Agreements, including with respect to, among other things, the consideration payable by us or any covenants or agreements with respect to the parties' respective operations during the pendency thereof. Any such amendments or alterations may have negative consequences to us, including, among other things, reducing our distributable cash flow.

We are subject to litigation related to the Atlas Mergers.

We are subject to litigation related to the Atlas Mergers, see "Item 3. Legal Proceedings." It is possible that additional claims beyond those that have already been filed will be brought by the current plaintiffs or by others in an effort to enjoin the Atlas Mergers or seek monetary relief from us. We cannot predict the outcome of these lawsuits, or others, nor can we predict the amount of time and expense that will be required to resolve the lawsuit(s). An unfavorable resolution of any such litigation surrounding the Atlas Mergers could delay or prevent the consummation of the Atlas Mergers. In addition, the cost to us defending the litigation, even if resolved in our favor, could be substantial.

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.

Targa Shareholder Litigation

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 is styled *Inspired Investors v. Joe Bob Perkins, et al.*, in the District Court of Harris County, Texas (the "TRC Lawsuit").

The TRC Plaintiff alleges a variety of causes of action challenging the disclosures related to the ATLS Merger. Generally, the TRC Plaintiff alleges that the TRC Director Defendants breached their fiduciary duties. The TRC Plaintiff further alleges that the registration statement filed on January 22, 2015 fails 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 seeks to enjoin the TRC Lawsuit Defendants from proceeding with or consummating the ATLS Merger unless and until TRC discloses the allegedly material omitted details. To the extent that the ATLS Merger is consummated before injunctive relief is granted, the TRC Plaintiff seeks to have the ATLS Merger rescinded. The TRC Plaintiff also seeks recissory damages and attorneys' fees.

Only two of the TRC Lawsuit Defendants have been served at this time, these defendants' date to answer, move to dismiss, or otherwise respond to the TRC Lawsuit is March 2, 2015. The remaining TRC Lawsuit Defendants' date to answer, move to dismiss or otherwise respond to the TRC Lawsuit has not yet been set. Targa cannot predict the outcome of this or any other lawsuit that might be filed subsequent to the date of the filing of this Annual Report, nor can Targa or Atlas predict the amount of time and expense that will be required to resolve the TRC Lawsuit. To resolve this matter, Targa published supplemental disclosures on February 11, 2015 and the parties are currently working on settlement documentation.

Table of Contents

## Atlas Unitholder Litigation

Between October and December 2014, five public unitholders of APL (the “APL Plaintiffs”) filed putative class action lawsuits against APL, ATLS, Atlas Pipeline Partners GP, LLC, the general partner of APL (“APL GP”), its managers, TRC, the Partnership, the general partner and Trident MLP Merger Sub LLC (the “APL Lawsuit Defendants”). These lawsuits are 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 since 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 Energy GP, LLC, the general partner of ATLS (“ATLS GP”), its managers, TRC and Trident GP Merger Sub LLC (the “ATLS Lawsuit Defendants” and, together with the APL Lawsuit Defendants, the “Atlas Lawsuit Defendants”). These lawsuits are 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 since been voluntarily dismissed.

The Atlas Lawsuit Plaintiffs allege a variety of causes of action challenging the Atlas Mergers. Generally, the APL Plaintiffs allege that (a) APL GP’s managers have breached the covenant of good faith and/or their fiduciary duties and (b) TRC, the Partnership, the general partner, Trident MLP Merger Sub LLC, 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 allege that (a) the premium offered to APL’s unitholders is inadequate, (b) APL agreed to contractual terms that will 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 allege that the registration statement filed on November 19, 2014 fails, among other things, to disclose allegedly material details concerning (i) Stifel, Nicolaus & Company, Incorporated’s analysis of the Transactions; (ii) Targa and Atlas’ financial projections; and (iii) the background of the Transactions. Generally, the ATLS Plaintiffs allege that (a) ATLS GP’s directors have breached the covenant of good faith and/or their fiduciary duties and (b) Targa, Trident GP Merger Sub LLC, and ATLS have aided and abetted in these alleged breaches of the covenant of good faith and/or fiduciary duties. The ATLS Plaintiffs further allege that (a) the premium offered to the ATLS unitholders is inadequate, (b) ATLS agreed to contractual terms that will 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 fails 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 Transactions; (ii) Targa and Atlas’ financial projections; and (iii) the background of the Transactions.

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. To the extent that the Atlas Mergers were consummated before injunctive relief was granted, the Atlas Lawsuit Plaintiffs sought to have the Atlas Mergers rescinded. The Atlas Lawsuit Plaintiffs also sought damages and seek 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 will 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. The parties to the Consolidated Atlas Lawsuits are drafting settlement agreements and expect to seek court approval of the settlements.

Table of Contents

We are a party to various administrative and regulatory proceedings that have arisen in the ordinary course of our business. See “Item 1. Business—Regulation of Operations” and “Item 1. Business—Environmental, Health and Safety Matters.”

Item 4. Mine Safety Disclosures.

Not applicable.

## PART II

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

## Market Information

Our common stock is listed on the New York Stock Exchange (“NYSE”) under the symbol “TRGP.” As of February 6, 2015, there were approximately 184 stockholders of record of our common stock. This number does not include stockholders whose shares are held in trust by other entities. The actual number of stockholders is greater than the number of holders of record. As of February 6, 2015, there were 42,143,395 shares of common stock outstanding.

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

Quarter Ended	Stock Prices		Dividends Declared
	High	Low	
December 31, 2014	\$139.99	\$88.01	\$0.77500
September 30, 2014	145.00	126.42	0.73250
June 30, 2014	160.97	99.30	0.69000
March 31, 2014	99.92	84.17	0.64750
December 31, 2013	89.74	72.24	0.60750
September 30, 2013	74.94	64.40	0.57000
June 30, 2013	69.43	60.01	0.53250
March 31, 2013	68.42	54.31	0.49500
December 31, 2012	53.38	45.74	0.45750
September 30, 2012	51.43	41.46	0.42250
June 30, 2012	49.91	39.89	0.39375
March 31, 2012	48.28	38.70	0.36500

Table of Contents

Stock Performance Graph

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

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

Our Dividend Policy

We intend to pay to our stockholders, on a quarterly basis, dividends equal to the cash we receive from our Partnership distributions, less reserves for expenses, future dividends and other uses of cash, including:

- federal income taxes, which we are required to pay because we are taxed as a corporation;
- the expenses of being a public company;
- other general and administrative expenses;
- general and administrative reimbursements to the Partnership;
- capital contributions to the Partnership upon the issuance by it of additional partnership securities if we choose to maintain the general partner's 2.0% interest;
- reserves our board of directors believes prudent to maintain;
- our obligation to satisfy tax obligations associated with previous sales of assets to the Partnership; and
- interest expense or principal payments on any indebtedness we incur.

### Table of Contents

If the Partnership is successful in implementing its business strategy and increasing distributions to its partners, we would generally expect to increase dividends to our stockholders, although the timing and amount of any such increased dividends will not necessarily be comparable to the increased Partnership distributions. We cannot assure you that any dividends will be declared or paid in the future.

The determination of the amount of cash dividends, including the quarterly dividend referred to above, if any, to be declared and paid will depend upon our financial condition, results of operations, cash flow, the level of our capital expenditures, future business prospects and any other matters that our board of directors deems relevant. The Partnership's debt agreements contain restrictions on the payment of distributions and prohibit the payment of distributions if the Partnership is in default. If the Partnership cannot make incentive distributions to the general partner or limited partner distributions to us, we will be unable to pay dividends on our common stock.

### The Partnership's Cash Distribution Policy

Under the Partnership's 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 the general partner to:

- provide for the proper conduct of the Partnership's 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; or
- provide funds for distributions to the Partnership's unitholders and to the general partner for any one or more of the upcoming four quarters.

The determination of available cash takes into account the possibility of establishing cash reserves in some quarterly periods that the Partnership may use to pay cash distributions in other quarterly periods, thereby enabling it to maintain relatively consistent cash distribution levels even if the Partnership's business experiences fluctuations in its cash from operations due to seasonal and cyclical factors. The general partner's determination of available cash also allows the Partnership to maintain reserves to provide funding for its growth opportunities. The Partnership makes its quarterly distributions from cash generated from its operations, and those distributions have grown over time as its business has grown, primarily as a result of numerous acquisitions and organic expansion projects that have been funded through external financing sources and cash from operations.

The actual cash distributions paid by the Partnership to its partners occur within 45 days after the end of each quarter. Since the second quarter of 2007, the Partnership has increased its quarterly cash distribution 23 times. During that time period, the Partnership has increased its quarterly distribution by 140% from \$0.3375 per common unit, or \$1.35 on an annualized basis, to \$0.81 per common unit, or \$3.24 on an annualized basis.

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

Table of Contents

Distributions from the Partnership and Dividends of TRC

We intend to pay dividends equal to the cash the Partnership distributes to us based on our ownership of Partnership securities, less the expenses of being a public company, other general and administrative expenses, federal income taxes, and reserves established by our board of directors.

The following table details the distributions declared and/or paid by the Partnership for the periods presented with respect to our 2% general partner interest, the associated IDRs and common units that we held during the periods indicated along with dividends declared by us to our shareholders for the same periods:

For the Three Months Ended	Date Paid or to be Paid	Cash Distributions				Distributions to Targa Resources Corp. (1)	Dividend Declared Per TRC Common Share	Total Dividend Declared to Common Shareholders
		Cash Distribution Per Limited Partner Unit	Limited Partner Units	General Partner Interest	IDRs			
(In millions, except per unit amounts)								
2014								
December 31, 2014	February 17, 2015	\$0.8100	\$10.5	\$ 2.7	\$38.4	\$ 51.6	\$0.77500	\$ 32.8
September 30, 2014	November 14, 2014	0.7975	10.3	2.6	36.0	48.9	0.73250	31.0
June 30, 2014	August 14, 2014	0.7800	10.1	2.5	33.7	46.3	0.69000	29.2
March 31, 2014	May 15, 2014	0.7625	9.9	2.4	31.7	44.0	0.64750	27.4
2013								
December 31, 2013	February 14, 2014	\$0.7475	\$9.7	\$ 2.3	\$29.5	\$ 41.5	\$0.60750	\$ 25.6
September 30, 2013	November 14, 2013	0.7325	9.5	2.2	26.9	38.6	0.57000	24.1
June 30, 2013	August 14, 2013	0.7150	9.3	2.0	24.6	35.9	0.53250	22.5
March 31, 2013	May 15, 2013	0.6975	9.0	1.9	22.1	33.0	0.49500	21.0
2012								
December 31, 2012	February 14, 2013	\$0.6800	\$8.8	\$ 1.8	\$20.1	\$ 30.7	\$0.45750	\$ 19.4
September 30, 2012	November 14, 2012	0.6625	8.6	1.5	16.1	26.2	0.42250	18.0
June 30, 2012	August 14, 2012	0.6425	8.3	1.5	14.4	24.2	0.39375	16.7
March 31, 2012	May 15, 2012	0.6225	8.1	1.4	12.7	22.2	0.36500	15.5

(1) Distributions to us comprise amounts attributable to our (i) limited partner units, (ii) general partner units and (iii) IDRs.

Recent Sales of Unregistered Securities

None.

Repurchase of Equity by Targa Resources Corp, or Affiliated Purchasers.

Period	Total number of shares withheld (1)	Average price per share	Total number of shares purchased as part of	Maximum number of shares that may yet be

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			publicly announced plans	purchased under the plan
February 1, 2014 - February 28, 2014	8,113	\$96.52	-	-
August 1, 2014 - August 31, 2014	13,855	133.55	-	-

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

62

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Table of Contents

## Item 6. Selected Financial Data.

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

	2014	2013	2012	2011	2010
	(In millions, except per share amounts)				
Statement of operations data:					
Revenues	\$8,616.5	\$6,314.7	\$5,679.0	\$6,843.2	\$5,391.0
Income from operations	640.5	368.2	336.3	351.1	196.1
Net income	423.0	201.3	159.3	215.4	63.3
Net income (loss) attributable to Targa Resources Corp.	102.3	65.1	38.1	30.7	(15.0 )
Dividends on Series B preferred stock	-	-	-	-	(9.5 )
Net income (loss) available to common shareholders	102.3	65.1	38.1	30.7	(202.3 )
Net income (loss) per common share - basic	2.44	1.56	0.93	0.75	(30.94 )
Net income (loss) per common share - diluted	2.43	1.55	0.91	0.74	(30.94 )
Balance sheet data (at end of period):					
Total assets	\$6,453.5	\$6,048.6	\$5,105.0	\$3,831.0	\$3,393.8
Long-term debt	2,885.4	2,989.3	2,475.3	1,567.0	1,534.7
Other:					
Dividends declared per share	\$2.8425	\$2.2050	\$1.6388	\$1.2063	\$0.0616
Dividends paid on series B preferred shares	\$-	\$-	\$-	\$-	\$238.0

Table of Contents

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. Also, the Partnership files a separate Annual Report on Form 10-K with the SEC.

Overview

Financial Presentation

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

We own general and limited partner interests, including Incentive Distribution Rights ("IDRs"), in Targa Resources Partners LP (the "Partnership"), a publicly traded Delaware limited partnership that is a leading United States provider of midstream natural gas and NGL services, with a growing presence in crude oil gathering and petroleum terminaling. Common units of the Partnership are listed on the NYSE under the symbol "NGLS."

Our primary business objective is to increase our cash available for dividends to our stockholders by assisting the Partnership in executing its business strategy. We may potentially facilitate the Partnership's growth through various forms of financial support, including, but not limited to, modifying the Partnership's IDRs, exercising the Partnership's IDR reset provision contained in its partnership agreement, making loans, making capital contributions in exchange for yielding or non-yielding equity interests or providing other financial support to the Partnership to support its ability to make distributions. We also may potentially enter into other economic transactions intended to increase our ability to make cash available for dividends over time. In addition, we may potentially acquire assets that could be candidates for acquisition by the Partnership, potentially after operational or commercial improvement or further development.

An indirect subsidiary of ours is the general partner of the Partnership. Because we control the general partner, under GAAP we must reflect our ownership interest in the Partnership on a consolidated basis. Accordingly, the Partnership's financial results are included in our consolidated financial statements even though the distribution or transfer of Partnership assets are limited by the terms of the partnership agreement, as well as restrictive covenants in the Partnership's lending agreements. The limited partner interests in the Partnership not owned by us are reflected in our results of operations as net income attributable to noncontrolling interests. Therefore, throughout this discussion, we make a distinction where relevant between financial results of the Partnership versus those of us as a standalone parent including our Non-Partnership subsidiaries.

The Partnership files its own separate Annual Report. The financial results presented in our consolidated financial statements will differ from the consolidated financial statements of the Partnership primarily due to the effects of:

- our separate debt obligations;
- federal income taxes;
- certain retained general and administrative costs applicable to us as a public company;
- certain administrative assets and liabilities incumbent as a provider of operational and support services to the Partnership;

· certain non-operating assets and liabilities that we retained;

· Partnership distributions and earnings allocable to third-party common unitholders which are included in non-controlling interest in our statements; and

· Partnership distributions applicable to our General Partner interest, Incentive Distribution Rights and investment in Partnership common units. While these are eliminated when preparing our consolidated financial statements, they nonetheless are the primary source of cash flow that supports the payment of dividends to our stockholders.

64

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Table of Contents

Our Operations

Currently, we have no separate, direct operating activities apart from those conducted by the Partnership. As such, our cash inflows will primarily consist of cash distributions from our interests in the Partnership. The Partnership is required to distribute all available cash at the end of each quarter after establishing reserves to provide for the proper conduct of its business or to provide for future distributions.

The Partnership's Operations

The Partnership 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. In connection with these business activities, the Partnership buys and sells natural gas, NGLs and NGL products, crude oil, condensate and refined products.

The Partnership is engaged in the business of:

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

The Partnership reports its 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 financial results of its hedging activities are reported in Other.

The Partnership's 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 North Texas, the Permian Basin of West Texas and Southeast New Mexico and 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.

The Partnership's Logistics and Marketing division is also referred to as its Downstream Business. The Partnership's 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, the storage and terminaling of refined petroleum products and crude oil and certain natural gas supply and marketing activities in support of our other businesses including services to LPG exporters. It also includes certain natural gas supply and marketing activities in support of the Partnership's other operations, as well as transporting natural gas and NGLs.

The Partnership's 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 the Partnership's Gathering and Processing segments and are predominantly located in Mont Belvieu and Galena Park, Texas and in Lake Charles, Louisiana.

The Partnership's 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 the Partnership's 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 the Partnership from its 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.

65

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### Table of Contents

Other contains the results of the Partnership's commodity hedging activities included in operating margin and the mark-to-market gains/losses that did not receive designation as cash-flow hedges.

### 2014 Developments

#### Logistics and Marketing Segment Expansion

#### International Exports

In September 2013, the Partnership commissioned Phase I of the international export expansion project, which includes its facilities at Mont Belvieu and the Galena Park Marine Terminal near Houston, Texas. Phase I of this project expanded the Partnership's export capability to approximately 3.5 to 4 MMBbl per month of propane and/or butane. Included in the Partnership's Phase I expansion is the capability to export international grade low ethane propane. With the completion of Phase I, the Partnership's capabilities expanded to include loading VLGC vessels in addition to the small and medium-sized vessels that the Partnership previously loaded for export.

As part of Phase II of this project during 2014, the Partnership added incremental capacity and operational efficiencies with the addition of refrigeration, another dock, a new pipeline between Mont Belvieu and Galena Park and a de-ethanizer that increased the effective capacity to 7.0 MMBbl per month. The total cost of the Partnership's international export expansion project was approximately \$480 million.

#### Condensate Splitter or Alternate Project

On March 31, 2014, the Partnership announced the approval to construct a condensate splitter at its Channelview Terminal on the Houston Ship Channel. The condensate splitter was supported by a long-term fee-based arrangement with Noble Americas Corp., a subsidiary of Noble Group Ltd. The initial project would have the capability to split approximately 35 MBbl/d of condensate into its various components, including naphtha, kerosene, gas oil, jet fuel and liquefied petroleum gas, and will provide segregated storage for the condensate and components.

Effective December 31, 2014, the Partnership and Noble agreed to modify the existing arrangements to build (i) a new terminal with significant storage capacity at Patriot; or (ii) a condensate splitter at Channelview with modified timing; or (iii) potentially both projects. The Partnership and Noble are evaluating these alternatives including final capabilities, capacities and capital costs. The modifications to the previous arrangements provide for the Partnership to receive an upfront payment and an enhanced economic benefit over time. The projects are now expected to be completed by the end of 2016 or 2017, depending on final project scope and on permitting.

#### CBF Train 5

In July 2014, the Partnership approved construction of a 100 MBbl/d fractionation expansion in Mont Belvieu, Texas. The 100 MBbl/d expansion will be fully integrated with its 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 the Partnership's LPG export terminal at Galena Park, Texas on the Houston Ship Channel. All environmental and internal approvals required to commence construction of the expansion are in place, and construction is underway and the Partnership expects completion of construction in mid-2016. Construction of the expansion will proceed without disruption to existing operations, and the Partnership estimates that total capital expenditures for the expansion and the related infrastructure enhancements at Mont Belvieu should be approximately \$385 million.

Table of Contents

Field Gathering and Processing Segment Expansion

Badlands

During 2013, the Partnership invested approximately \$250 million to expand its gathering and processing business in the Williston Basin, North Dakota assets. The Partnership increased its crude gathering and natural gas gathering operations substantially with the addition of pipelines and associated facilities and added an additional 20 MMcf/d natural gas processing plant. During 2014, the Partnership invested approximately \$165 million for further expansion of this business, including an additional cryogenic processing plant.

North Texas and SAOU

In May 2014, the Partnership commenced commercial operations of the 200 MMcf/d cryogenic Longhorn processing plant in North Texas, and in June 2014, the Partnership commenced commercial operations of the 200 MMcf/d cryogenic High Plains processing plant in the Permian Basin. We believe these plants will enable North Texas and SAOU to meet increasing production from continued producer activity in North Texas and the eastern side of the Permian Basin.

Growth Investments in the Permian and Williston Basins

In October 2014, the Partnership announced that it intends to build a new 300 MMcf/d cryogenic processing plant with an anticipated start-up in early 2016. This plan will also include related gathering and compression infrastructure in the Delaware Basin of Winkler County, Texas, west of the Partnership's existing Sand Hills gas processing plant.

In October 2014, the Partnership also announced that it intends to build a new 200 MMcf/d cryogenic processing plant to be located in McKenzie County, North Dakota with an anticipated start-up in 2016.

Given the significant decrease in commodity prices and expected reductions in producer activity since those announcements, the Partnership is reevaluating the capacity and expected timing for both of these projects.

In the current market environment, we are actively monitoring producer responses to changes in the commodity price environment and will continue to adjust our growth capital expenditure programs to meet expected producer requirements.

Additionally, the Partnership expects to have other growth capital expenditures in 2015 related to the continued build out of its gathering and processing systems and logistics capabilities.

Pending Atlas Mergers

On October 13, 2014, we and the Partnership announced two proposed merger transactions which would result in the Partnership's acquisition of Atlas Pipeline Partners, L.P (APL), a Delaware limited partnership, and the Targa acquisition of Atlas Energy, L.P. (ATLS), a Delaware limited partnership, which owns the APL general partner. Upon consummation of these mergers, Targa would relinquish all APL ownership interests and merge the APL general partner into the Partnership. Each of the Transactions is contingent on one another, and the Transactions are expected to close concurrently on February 28, 2015, subject to the approval of Targa's stock issuance in connection with the ATLS Merger by Targa's stockholders and the approval of the Atlas Mergers by unitholders of ATLS and APL, as applicable, and other customary closing conditions.

APL 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; a provider of natural gas gathering services in the Appalachian Basin in the northeastern

region of the United States and a provider of NGL transportation services in the southwestern region of the United States.

67

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Table of Contents

Strategic Rationale:

We believe that the combination of Targa Resources Partners and APL creates a premier midstream franchise with increased scale and geographic diversity, and creates one of the largest diversified MLPs on an enterprise value basis.

The acquisitions add the Woodford/SCOOP, Mississippi Lime, Eagle Ford and additional Permian assets to the Partnership's existing Permian, Bakken, Barnett, and Louisiana Gulf Coast gathering and processing operations.

Combined position across the Permian Basin enhances service capabilities in one of the most active producing basins in North America, with a combined 1,439 MMcf/d of processing capacity and 10,300 miles of pipelines.

Strong growth outlook with significant announced combined organic growth capital expenditures.

Growing NGL production from gathering and processing business supports the Partnership's leading NGL fractionation and export position.

Enhances credit profile and results in an estimated 60-70% pro forma fee-based margin.

Underlying growth in the businesses drives incrementally higher distribution and dividend growth.

Please see Note 4 to the "Consolidated Financial Statements" beginning on page F-1 of this Annual Report.

Accounts Receivable Securitization Facility

The Securitization Facility provides up to \$300.0 million of borrowing capacity at LIBOR market index rates plus a margin through December 11, 2015. Under the Securitization Facility, two of the Partnership's consolidated subsidiaries (Targa Liquids Marketing and Trade LLC ("TLMT") and Targa Gas Marketing LLC ("TGM")) 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, TGM or the Partnership. Any excess receivables are eligible to satisfy the claims of creditors of TLMT, TGM or the Partnership. As of December 31, 2014, total funding under the Securitization Facility was \$182.8 million.

Other Financing Activities

On July 21, 2014, Standard & Poor's Ratings Services ("S&P") raised the Partnership's corporate credit rating to 'BB+' from 'BB' and raised the Partnership's credit rating on its senior unsecured notes to 'BB+' from 'BB'.

On September 9, 2014, Moody's Investors Service ("Moody's") raised the Partnership's corporate credit rating to 'Ba1' from 'Ba2' and raised the Partnership's credit rating on its senior unsecured notes to 'Ba2' from 'Ba3'.

On October 13, 2014, in conjunction with the announced agreements to acquire APL and ATLS, S&P placed the Partnership's 'BB+' corporate credit and senior unsecured debt ratings on CreditWatch with positive implications. Also on October 14, 2014, Moody's affirmed the Partnership's Ba1 Corporate Family Rating and Ba2 senior unsecured note rating.

In October 2014, the Partnership privately placed \$800.0 million in aggregate principal amount of 4 % Senior Notes due 2019 (the “4 % Notes”). The 4 % Notes resulted in approximately \$790.8 million of net proceeds, which were used to reduce borrowings under the TRP Revolver and the Partnership’s Securitization Facility and for general partnership purposes.

In November 2014, the Partnership redeemed its outstanding 7 % Senior Notes due 2018 (the “7 % Notes”) paying \$259.8 million plus accrued interest per the terms of the note agreement to redeem the outstanding balance of the 7 % Notes. The redemption resulted in a \$12.4 million loss on debt 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 issue costs.

## Table of Contents

In July 2013, the Partnership filed with the SEC a universal shelf registration statement that, subject to effectiveness at the time of use, allows the Partnership to issue up to an aggregate of \$800 million of debt or equity securities (the “July 2013 Shelf”). In August 2013, the Partnership entered into an Equity Distribution Agreement under the July 2013 Shelf (the “August 2013 EDA”), pursuant to which the Partnership may sell through its sales agents, at its option, up to an aggregate of \$400 million of the Partnership common units. In May 2014, the Partnership entered into an additional Equity Distribution Agreement under the July 2013 Shelf (the “May 2014 EDA”), pursuant to which the Partnership may sell through its sales agents, at its option, up to an aggregate of \$400 million of the Partnership common units.

During 2014, pursuant to the August 2013 EDA and the May 2014 EDA, the Partnership 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 the Partnership’s sales agent), which were used to reduce borrowings under the TRP Revolver and for general partnership purposes. We contributed \$8.4 million to the Partnership to maintain our 2% general partner interest during this period, of which \$1.0 million was settled in January 2015.

## Recent Accounting Pronouncements

In April 2014, the FASB issued ASU No. 2014-08, Presentation of Financial Statements (Topic 205) and Property, Plant and Equipment (Topic 360), Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity. The amendment, required to be applied prospectively for reporting periods beginning after December 15, 2014, limits discontinued operations reporting to disposals of components of an entity that represent strategic shifts that have, or will have, a major effect on operations and financial results. The amendment requires expanded disclosures for discontinued operations and also requires additional disclosures regarding disposals of individually significant components that do not qualify as discontinued operations. Early adoption is permitted, but only for disposals (or classifications as held for sale) that have not been reported in financial statements previously issued or available for issuance.

In May 2014, the FASB issued 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 will be effective for us starting in the first quarter of 2017. Early adoption is not permitted. 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 first quarter report in 2017. We have commenced our analysis of the new standard and its impact on our revenue recognition practices.

In August 2014, the FASB issued ASU No. 2014-15, Presentation of Financial Statements—Going Concern (Subtopic 205-40), Disclosure of Uncertainties about an Entity’s Ability to Continue as a Going Concern. The amendment is effective for the annual period beginning after December 15, 2016, and for annual and interim periods thereafter, with early adoption permitted. The amendment requires an entity’s management to evaluate for each annual and interim reporting period whether there are conditions or events, considered in the aggregate, that raise substantial doubt about

the entity's ability to continue as a going concern within one year after the date that the financial statements are issued or available to be issued. If substantial doubt is raised, further analysis and disclosures are required, including management's plans to mitigate the adverse conditions or events.

Table of Contents

In November 2014, FASB issued ASU No. 2014-17, Business Combinations (Topic 805): Pushdown Accounting (a consensus of the FASB Emerging Issues Task Force), with an effective date of November 18, 2014. The amendment provides an acquired entity the option to apply push-down accounting in its separate financial statements when a change-in-control event occurs.

## Factors That Significantly Affect the Partnership's Results

The Partnership's results of operations are substantially impacted by the volumes that move through its gathering, processing and logistics assets, changes in commodity prices, contract terms, the impact of hedging activities and the cost to operate and support assets.

## Volumes

In the Partnership's gathering and processing operations, plant inlet volumes and capacity utilization rates generally are driven by wellhead production and the Partnership's 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 the Partnership's operations. The factors that impact the gathering and processing volumes also impact the total volumes that flow to the Downstream Business. In addition, fractionation volumes are also affected by the location of the resulting mixed NGLs, available pipeline capacity to transport NGLs to the Partnership's fractionators and its competitive and contractual position relative to other fractionators.

## 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:

	Natural Gas \$/MMBtu	Illustrative Targa NGL \$/gal	Crude Oil \$/Bbl
Average Quarterly & Annual Prices	(1)	(2)	(3)
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
2012			
4th Quarter	\$ 3.41	\$ 0.88	\$88.23
3rd Quarter	2.80	0.86	92.20
2nd Quarter	2.21	0.94	93.35
1st Quarter	2.72	1.18	103.03
2012 Average	2.79	0.97	94.20

- (1) Natural gas prices are based on average quarterly and annual prices from Henry Hub I-FERC commercial index prices.  
NGL prices are based on quarterly weighted average prices and annual averages of prices from Mont Belvieu
- (2) Non-TET monthly commercial index prices. Illustrative Targa NGL contains 44% ethane, 30% propane, 11% natural gasoline, 5% isobutane and 10% 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.

## Table of Contents

### 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 the Partnership's Gathering and Processing division, other than fee-based contracts in Badlands and certain other gathering and processing services, can have a material impact on its profitability, especially those contracts that create direct exposure to changes in energy prices by paying the Partnership 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. The Partnership's gathering and processing contract mix and, accordingly, their 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, their expansion into regions where different types of contracts are more common and other market factors. For example, the Partnership's Badlands 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 the Partnership's 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 the Partnership's Commodity Price Hedging Activities

The Partnership has hedged the commodity price risk associated with a portion of its expected natural gas and condensate equity volumes through 2017 and NGL equity volumes through 2015 by entering into financially settled derivative transactions. Historically, these transactions have included both swaps and purchased puts (or floors). The primary purpose of its commodity risk management activities is to hedge its exposure to price risk and to mitigate the impact of fluctuations in commodity prices on cash flow. The Partnership also actively manages the Downstream Business product inventory and other working capital levels to reduce exposure to changing NGL prices. For additional information regarding the Partnership's 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 the Partnership's results as volumes fluctuate through its systems. Continued expansion of existing assets will also give rise to additional operating expenses, which will affect the Partnership's results. The employees supporting the Partnership's operations are employees of Targa Resources LLC, a Delaware limited liability company, and an indirect wholly-owned subsidiary of us. The Partnership reimburses us for the payment of certain operating expenses, including compensation and benefits of operating personnel assigned to the Partnership's assets.

### General and Administrative Expenses

We perform centralized corporate functions for the Partnership, such as legal, accounting, treasury, insurance, risk management, health, safety, environmental, information technology, human resources, credit, payroll, internal audit, taxes engineering and marketing. Other than our direct costs of being a separate public reporting company, these costs are reimbursed by the Partnership. See "Item 13. Certain Relationships and Related Transactions, and Director

Independence.”

#### General Trends and Outlook

We expect the midstream energy business environment to continue to be affected by the following key trends: demand for the Partnership’s 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, the Partnership’s actual results may vary materially from our expected results.

71

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## Table of Contents

### Demand for the Partnership's 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 2015. In the Partnership's Field Gathering and Processing areas of operation, producers are likely to reduce 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 the Partnership's services. Producer activity generates demand in the Partnership's Downstream Business for fractionation and other fee-based services, which may decrease in the near term. As prices have declined, demand for the Partnership's 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 the Partnership's systems.

The Partnership's operating income generally improves in an environment of higher natural gas, NGL and condensate prices, primarily as a result of its percent-of-proceeds contracts. The Partnership's 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 its control and have been volatile. In a declining commodity price environment, without taking into account the Partnership's hedges, the Partnership will realize a reduction in cash flows under its 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 2015, and, as a result, demand for the services that we provide may decrease. Across the Partnership's operations and particularly in the Partnership's Downstream Business, the Partnership benefits from long-term fee-based arrangements for its services, regardless of the actual volumes processed or delivered. The significant level of margin we derive from fee-based arrangements combined with the Partnership's hedging arrangements helps to mitigate the Partnership's exposure to commodity price movements. For additional information regarding the Partnership's hedging activities, see "Item 7A. Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk."

### Volatile Capital Markets

The Partnership is dependent on its abilities to access the equity and debt capital markets in order to fund acquisitions and expansion expenditures. Global financial markets have been, and are expected to continue to be, volatile and disrupted and weak economic conditions may cause a significant decline in commodity prices. As a result, we and the Partnership may be unable to raise equity or debt capital on satisfactory terms, or at all, which may negatively impact the timing and extent to which we and the Partnership execute growth plans. Prolonged periods of low commodity prices or volatile capital markets may impact our and the Partnership's ability or willingness to enter into new hedges, fund organic growth, connect to new supplies of natural gas, execute acquisitions or implement expansion capital expenditures.

### Increased Regulation

Additional regulation in various areas has the potential to materially impact the Partnership's operations and financial condition. For example, increased regulation of hydraulic fracturing used by producers 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 the Partnership's revenues by decreasing the volumes of natural gas, NGLs or crude oil through its facilities and reducing the utilization of its assets." Similarly, the forthcoming rules and regulations of the CFTC may limit the Partnership's ability or increase the cost to use derivatives, which could create more volatility and less predictability in its results of operations.

Table of Contents

How We Evaluate Our Operations

Our consolidated operations include the operations of the Partnership due to our ownership and control of the general partner. We currently have no direct operating activities separate from those conducted by the Partnership. Our financial results differ from the Partnership's due to the financial effects of: noncontrolling interests in the Partnership, our separate debt obligations, certain non-operating costs associated with assets and liabilities that we retained and were not included in asset conveyances to the Partnership, and certain general and administrative costs applicable to us as a separate public company. We monitor these non-partnership financial items to ensure proper reflection of the Partnership and Non-Partnership results.

Distributable Cash Flow

Management's primary measure of analyzing our performance is the non-GAAP measure distributable cash flow.

We define distributable cash flow as distributions due to us from the Partnership, less our specific general and administrative costs as a separate public reporting entity, the interest carry costs associated with our debt and taxes attributable to our earnings. Distributable cash flow is a significant performance metric used by us and by external users of our financial statements, such as investors, commercial banks, research analysts and others to compare basic cash flows generated by us to the cash dividends we expect to pay our shareholders. Using this metric, management and external users of our financial statements can quickly compute the coverage ratio of estimated cash flows to planned cash dividends. Distributable cash flow is also an important financial measure for our shareholders since it serves as an indicator of our success in providing a cash return on investment. Specifically, this financial measure indicates to investors whether or not we are generating cash flow at a level that can sustain or support an increase in our quarterly dividend rates. Distributable cash flow is also a quantitative standard used throughout the investment community because the share value is generally determined by the share's yield (which in turn is based on the amount of cash dividends the entity pays to a shareholder).

The economic substance behind our use of distributable cash flow is to measure the ability of our assets to generate cash flow sufficient to pay dividends to our investors.

The GAAP measure most directly comparable to distributable cash flow is net income. Distributable cash flow should not be considered as an alternative to GAAP net income. Distributable cash flow is not a presentation made in accordance with GAAP and 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.

Table of Contents

## Our Non-GAAP Measures

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 process.

	2014	2013	2012
	(In millions)		
Reconciliation of Net Income of Targa Resources Corp. to Distributable Cash Flow			
Net income of Targa Resources Corp.	\$423.0	\$201.3	\$159.3
Less: Net income of Targa Resources Partners LP	(505.1)	(258.6)	(203.2)
Net loss for TRC Non-Partnership	(82.1 )	(57.3 )	(43.9 )
TRC Non-Partnership income tax expense	63.2	45.3	32.7
Distributions from the Partnership	190.8	149.0	103.3
Non-cash loss (gain) on hedges	-	0.3	(2.2 )
Loss on debt redemptions and amendments	-	-	0.2
Depreciation - Non-Partnership assets	4.5	0.3	0.3
Current cash tax expense (1)	(63.5 )	(31.0 )	(20.8 )
Taxes funded with cash on hand (2)	11.8	10.0	8.7
Distributable cash flow	\$124.7	\$116.6	\$78.3

Excludes \$4.7 million of non-cash current tax expense arising from amortization of deferred long-term tax assets (1) from drop down gains realized for tax purposes and paid in 2010 for the years ended December 31, 2014, 2013 and 2012.

(2) Current period portion of amount established at our IPO to fund taxes on deferred gains related to drop down transactions that were treated as sales for income tax purposes.

	2014	2013	2012
	(In millions)		
Targa Resources Corp. Distributable Cash Flow			
Distributions declared by Targa Resources Partners LP associated with:			
General Partner Interests	\$10.2	\$8.4	\$6.2
Incentive Distribution Rights	139.8	103.1	63.3
Common Units	40.8	37.5	33.8
Total distributions declared by Targa Resources Partners LP	190.8	149.0	103.3
Income (expenses) of TRC Non-Partnership			
General and administrative expenses	(8.2 )	(8.4 )	(8.2 )
Interest expense, net	(3.3 )	(3.1 )	(4.0 )
Current cash tax expense (1)	(63.5 )	(31.0 )	(20.8 )
Taxes funded with cash on hand (2)	11.8	10.0	8.7
Other income (expense)	(2.9 )	0.1	(0.7 )
Distributable cash flow	\$124.7	\$116.6	\$78.3

Excludes \$4.7 million of non-cash current tax expense arising from amortization of deferred long-term tax assets (1) from drop down gains realized for tax purposes and paid in 2010 for the years ended December 31, 2014, 2013 and 2012.

(2) Current period portion of amount established at our IPO to fund taxes on deferred gains related to drop down

transactions that were treated as sales for income tax purposes.

74

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## Table of Contents

### How We Evaluate the Partnership's Operations

The Partnership's profitability of its business segments is a function of the difference between: (i) the revenues the Partnership receives from its operations, including fee-based revenues from services and revenues from the natural gas, NGLs, crude oil and condensate the Partnership sells, and (ii) the costs associated with conducting the Partnership's operations, including the costs of wellhead natural gas, crude oil and mixed NGLs that the Partnership purchases as well as operating, general and administrative costs and the impact of commodity hedging activities. Because commodity price movements tend to impact both revenues and costs, increases or decreases in the Partnership's revenues alone are not necessarily indicative of increases or decreases in its profitability. The Partnership's 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 its systems are important factors in determining its profitability. The Partnership's profitability is also affected by the NGL content in gathered wellhead natural gas, supply and demand for its products and services, utilization of its assets and changes in its customer mix.

The Partnership's profitability is also impacted by fee-based revenues. The Partnership's 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 the Partnership's 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

The Partnership's profitability is impacted by its 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 its 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, the Partnership's profitability is impacted by its ability to add new sources of mixed NGL supply, typically connected by third-party transportation, to its Downstream Business' fractionation facilities. The Partnership fractionates NGLs generated by its gathering and processing plants, as well as by contracting for mixed NGL supply from third-party facilities.

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

As part of monitoring the efficiency of its operations, the Partnership measures the difference between the volume of natural gas received at the wellhead or central delivery points on its gathering systems and the volume received at the inlet of its processing plants as an indicator of fuel consumption and line loss. The Partnership also tracks 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 its facilities. Similar tracking is performed for its crude oil gathering and logistics assets. These volume, recovery and fuel consumption

measurements are an important part of the Partnership's 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 the Partnership's operating expenses. These expenses, other than fuel and power, generally remain relatively stable and independent of the volumes through its systems, but fluctuate depending on the scope of the activities performed during a specific period.

75

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## Table of Contents

### 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. The Partnership has seen a substantial increase in its total capital spent since 2010 and currently has significant internal growth projects.

### Gross Margin

The Partnership defines gross margin as revenues less purchases. It is impacted by volumes and commodity prices as well as by the Partnership's contract mix and commodity hedging program. The Partnership defines 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

The Partnership defines operating margin as gross margin less operating expenses. Operating margin is an important performance measure of the core profitability of the Partnership's operations.

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

the financial performance of the Partnership's assets without regard to financing methods, capital structure or historical cost basis;

the Partnership's 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 the Partnership's 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, the Partnership's definition 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

The Partnership defines Adjusted EBITDA as net income attributable to Targa Resources Partners LP before: interest; income taxes; depreciation and amortization; gains or losses on debt repurchases and redemptions, early debt extinguishments and asset disposals; non-cash risk management activities related to derivative instruments; changes in the fair value of the Badlands acquisition contingent consideration; non-cash compensation on Partnership equity grants and the non-controlling interest portion of depreciation and amortization expenses. Adjusted EBITDA is used as a supplemental financial measure by the Partnership and by external users of its financial statements such as investors, commercial banks and others. The economic substance behind the Partnership's use of Adjusted EBITDA is to measure the ability of its assets to generate cash sufficient to pay interest costs, support its indebtedness and make distributions to its investors.

### Table of Contents

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 the Partnership's 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 the Partnership's industry, the Partnership's 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

The Partnership defines distributable cash flow as net income attributable to Targa Resources Partners LP plus depreciation and amortization, deferred taxes and amortization of debt issue costs included in interest expense, adjusted for non-cash risk management activities related to derivative instruments, debt repurchases and redemptions, early debt extinguishments, non-cash compensation on Partnership equity grants and asset disposals, less maintenance capital expenditures (net of any reimbursements of project costs) and changes in the fair value of the Badlands acquisition contingent consideration. This measure includes any impact of noncontrolling interests.

Distributable cash flow is a significant performance metric used by the Partnership and by external users of the Partnership's financial statements, such as investors, commercial banks and research analysts, to compare basic cash flows generated by the Partnership (prior to the establishment of any retained cash reserves by the board of directors of its general partner) to the cash distributions the Partnership expects to pay the Partnership's unitholders. Using this metric, the Partnership's management and external users of its 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 the Partnership's unitholders since it serves as an indicator of the Partnership's success in providing a cash return on investment. Specifically, this financial measure indicates to investors whether or not the Partnership is generating cash flow at a level that can sustain or support an increase in the Partnership's 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 unitholder).

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 the Partnership's 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 the Partnership's industry, the Partnership's 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.



Table of Contents

## Non-GAAP Financial Measures of the Partnership

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

	2014	2013	2012
	(In millions)		
Reconciliation of Targa Resources Partners LP gross margin and operating margin to net income:			
Gross margin	\$1,569.6	\$1,177.7	\$1,004.7
Operating expenses	(433.0 )	(376.2 )	(313.0 )
Operating margin	1,136.6	801.5	691.7
Depreciation and amortization expenses	(346.5 )	(271.6 )	(197.3 )
General and administrative expenses	(139.8 )	(143.1 )	(131.6 )
Interest expense, net	(143.8 )	(131.0 )	(116.8 )
Income tax expense	(4.8 )	(2.9 )	(4.2 )
Gain (loss) on sale or disposition of assets	4.8	(3.9 )	(15.6 )
Loss on debt redemptions and amendments	(12.4 )	(14.7 )	(12.8 )
Change in contingent consideration	-	15.3	-
Other, net	11.0	9.0	(10.2 )
Net income	\$505.1	\$258.6	\$203.2

	2014	2013	2012
	(In millions)		
Reconciliation of net cash provided by Targa Resources Partners LP operating activities to Adjusted EBITDA:			
Net cash provided by operating activities	\$838.5	\$411.4	\$465.4
Net income attributable to noncontrolling interests	(37.4 )	(25.1 )	(28.6 )
Interest expense	143.8	131.0	116.8
Non-cash interest expense, net (1)	(11.2 )	(15.5 )	(17.6 )
Current income tax expense	3.2	2.0	2.5
Other (2)	(18.4 )	(13.7 )	(15.6 )
Changes in operating assets and liabilities which used (provided) cash:			
Accounts receivable and other assets	(58.6 )	230.3	(96.1 )
Accounts payable and other liabilities	110.4	(85.2 )	91.7
Targa Resources Partners LP Adjusted EBITDA	\$970.3	\$635.2	\$518.5

(1) Includes amortization of debt issuance costs, discount and premium.

(2) Includes equity earnings from unconsolidated investments – net of distributions, accretion expense associated with asset retirement obligations and noncontrolling interest portion of depreciation and amortization expenses.

Table of Contents

	2014	2013	2012
	(In millions)		
Reconciliation of Net Income of Targa Resources Partners LP to Adjusted EBITDA:			
Net income attributable to Targa Resources Partners LP	\$467.7	\$233.5	\$174.6
Interest expense, net	143.8	131.0	116.8
Income tax expense	4.8	2.9	4.2
Depreciation and amortization expenses	346.5	271.6	197.3
(Gain) loss on sale or disposition of assets	(4.8 )	3.9	15.6
Loss on debt redemptions and amendments	12.4	14.7	12.8
Change in contingent consideration	-	(15.3 )	-
Compensation on TRP equity grants (1)	9.2	6.0	3.5
Non-cash risk management activities	4.7	(0.5 )	5.4
Noncontrolling interests adjustment (2)	(14.0 )	(12.6 )	(11.8 )
Targa Resources Partners LP Adjusted EBITDA	\$970.3	\$635.2	\$518.5

(1) The definition of Adjusted EBITDA was changed in 2014 to exclude non-cash compensation on equity grants.

(2) Noncontrolling interest portion of depreciation and amortization expenses.

	2014	2013	2012
	(In millions)		
Reconciliation of net income of Targa Resources Partners LP to Distributable Cash flow:			
Net income attributable to Targa Resources Partners LP	\$467.7	\$233.5	\$174.6
Depreciation and amortization expenses	346.5	271.6	197.3
Deferred income tax expense	1.6	0.9	1.7
Non-cash interest expense, net (1)	11.2	15.5	17.6
Loss on debt redemptions and amendments	12.4	14.7	12.8
Change in contingent consideration	-	(15.3 )	-
(Gain) loss on sale or disposition of assets	(4.8 )	3.9	15.6
Compensation on TRP equity grants	9.2	6.0	3.6
Non-cash risk management activities	4.7	(0.5 )	5.4
Maintenance capital expenditures	(79.1 )	(79.9 )	(67.6 )
Other (2)	(6.2 )	(4.1 )	(3.5 )
Targa Resources Partners LP distributable cash flow	\$763.2	\$446.3	\$357.5

(1) Includes amortization of debt issuance costs, discount and premium.

(2) Includes the noncontrolling interests portion of maintenance capital expenditures, depreciation and amortization expenses.

Table of Contents

## Financial Information – Partnership versus Non-Partnership

As a supplement to the financial statements included in this Annual Report, we present the following tables, which segregate our Consolidated Balance Sheets, results of operations and statement of cash flows between Partnership and Non-Partnership activities. Partnership results are presented the same basis reported in the Partnership's Annual Report on Form 10-K. Except when otherwise noted, the remainder of this management's discussion and analysis refers to these disaggregated results.

## Balance Sheets – Partnership versus Non-Partnership

	December 31, 2014			December 31, 2013		
	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
	(In millions)					
<b>ASSETS</b>						
Current assets:						
Cash and cash equivalents (1)	\$81.0	\$72.3	\$ 8.7	\$66.7	\$57.5	\$ 9.2
Trade receivables, net	567.3	566.8	0.5	658.8	658.6	0.2
Inventory	168.9	168.9	-	150.7	150.7	-
Deferred income taxes	0.1	-	0.1	0.1	-	0.1
Assets from risk management activities	44.4	44.4	-	2.0	2.0	-
Other current assets (1)	20.9	3.8	17.1	18.9	7.1	11.8
Total current assets	882.6	856.2	26.4	897.2	875.9	21.3
Property, plant and equipment, at cost (3)	6,521.1	6,514.3	6.8	5,758.4	5,751.6	6.8
Accumulated depreciation	(1,696.5)	(1,689.7)	(6.8)	(1,408.5)	(1,406.2)	(2.3)
Property, plant and equipment, net (3)	4,824.6	4,824.6	-	4,349.9	4,345.4	4.5
Intangible assets, net	591.9	591.9	-	653.4	653.4	-
Long-term assets from risk management activities	15.8	15.8	-	3.1	3.1	-
Other long-term assets (2)	138.6	88.7	49.9	145.0	93.6	51.4
Total assets	\$6,453.5	\$6,377.2	\$ 76.3	\$6,048.6	\$5,971.4	\$ 77.2
<b>LIABILITIES AND OWNERS' EQUITY</b>						
Current liabilities:						
Accounts payable and accrued liabilities (4)	\$638.5	\$592.7	\$ 45.8	\$761.8	\$721.2	\$ 40.6
Affiliate payable (receivable) (5)	-	53.2	(53.2)	-	52.4	(52.4)
Accounts receivable securitization facility	182.8	182.8	-	-	-	-
Deferred income taxes (6)	0.6	-	0.6	0.6	-	0.6
Liabilities from risk management activities	5.2	5.2	-	8.0	8.0	-
Total current liabilities	827.1	833.9	(6.8)	770.4	781.6	(11.2)

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Long-term debt	2,885.4	2,783.4	102.0	2,989.3	2,905.3	84.0
Long-term liabilities from risk management activities	-	-	-	1.4	1.4	-
Deferred income taxes (6)	138.2	13.7	124.5	135.5	12.1	123.4
Other long-term liabilities (7)	63.3	57.8	5.5	60.7	52.6	8.1
Total liabilities	3,914.0	3,688.8	225.2	3,957.3	3,753.0	204.3
Total owners' equity	2,539.5	2,688.4	(148.9)	2,091.3	2,218.4	(127.1)
Total liabilities and owners' equity	\$6,453.5	\$6,377.2	\$ 76.3	\$6,048.6	\$5,971.4	\$ 77.2

The major Non-Partnership balance sheet items relate to:

- (1) Corporate assets consisting of cash and prepaid insurance.
- (2) Long-term prepaid tax assets primarily related to gains on 2010 drop-down transactions recognized as sales of assets for tax purposes.
- (3) Assets excluded from drop-down transactions were fully depreciated in 2014.
- (4) Accrued current liabilities related to payroll and incentive compensation plans and taxes payable.
- (5) Receivable related to intercompany billings arising from our providing management, commercial, operational, financial and administrative services to the Partnership.
- (6) Current and long-term deferred income tax balances.
- (7) Long-term liabilities related to TRC incentive compensation plans and deferred rent related to the headquarters' office lease.

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Table of Contents

Results of Operations – Partnership versus Non-Partnership

	Year Ended December 31, 2014			2013			2012		
	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
	(In millions)								
Revenues (1)	\$8,616.5	\$8,616.5	\$ -	\$6,314.7	\$6,314.9	\$(0.2 )	\$5,679.0	\$5,676.9	\$ 2.1
Costs and Expenses:									
Product purchases	7,046.9	7,046.9	-	5,137.2	5,137.2	-	4,672.3	4,672.2	0.1
Operating expenses	433.1	433.0	0.1	376.3	376.2	0.1	313.1	313.0	0.1
Depreciation and amortization (2)	351.0	346.5	4.5	271.9	271.6	0.3	197.6	197.3	0.3
General and administrative (3)	148.0	139.8	8.2	151.5	143.1	8.4	139.8	131.6	8.2
Other operating (income) expense	(3.0 )	(3.0 )	-	9.6	9.6	-	19.9	19.9	-
Income (loss) from operations	640.5	653.3	(12.8 )	368.2	377.2	(9.0 )	336.3	342.9	(6.6 )
Other income (expense):									
Interest expense, net - third party (4)	(147.1 )	(143.8 )	(3.3 )	(134.1 )	(131.0 )	(3.1 )	(120.8 )	(116.8 )	(4.0 )
Equity earnings	18.0	18.0	-	14.8	14.8	-	1.9	1.9	-
Loss on debt redemptions and amendments	(12.4 )	(12.4 )	-	(14.7 )	(14.7 )	-	(12.8 )	(12.8 )	-
Other income (expense) (5)	(8.0 )	(5.2 )	(2.8 )	15.3	15.2	0.1	(8.4 )	(7.8 )	(0.6 )
Income (loss) before income taxes	491.0	509.9	(18.9 )	249.5	261.5	(12.0 )	196.2	207.4	(11.2 )
Income tax expense (6)	(68.0 )	(4.8 )	(63.2 )	(48.2 )	(2.9 )	(45.3 )	(36.9 )	(4.2 )	(32.7 )
Net income (loss)	423.0	505.1	(82.1 )	201.3	258.6	(57.3 )	159.3	203.2	(43.9 )
Less: Net income attributable to	320.7	37.4	283.3	136.2	25.1	111.1	121.2	28.6	92.6

noncontrolling  
interests (7)  
Net income  
(loss) after  
noncontrolling  
interests

\$102.3    \$467.7    \$(365.4 ) \$65.1    \$233.5    \$(168.4 ) \$38.1    \$174.6    \$(136.5 )

The major Non-Partnership results of operations relate to:

- (1) Amortization of AOCI related to Versado hedges dropped down to the Partnership, and AOCI related to terminated hedges (fully amortized during 2013).
- (2) Depreciation on assets excluded from drop-down transactions (fully depreciated in 2014).
- (3) General and administrative expenses retained by TRC related to its status as a public entity.
- (4) Interest expense related to TRC debt obligations.
- (5) Legal and merger costs incurred in 2014 related to TRC pending the Atlas Mergers.
- (6) Federal and state income taxes.
- (7) Noncontrolling interests in the net income of the Partnership.

Table of Contents

Statements of Cash Flows – Partnership versus Non-Partnership

	Year Ended December 31, 2014			2013			2012		
	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
(In millions)									
Cash flows from operating activities									
Net income (loss)	\$423.0	\$505.1	\$(82.1 )	\$201.3	\$258.6	\$(57.3 )	\$159.3	\$203.2	\$(43.9 )
Adjustments to reconcile net income to net cash provided by operating activities:									
Amortization in interest expense (1)	11.8	11.2	0.6	15.9	15.5	0.4	18.2	17.6	0.6
Compensation on equity grants (2)	14.3	9.2	5.1	13.2	6.0	7.2	17.5	3.6	13.9
Depreciation and amortization expense (3)	351.0	346.5	4.5	271.9	271.6	0.3	197.6	197.3	0.3
Accretion of asset retirement obligations	4.5	4.4	0.1	4.0	3.9	0.1	4.0	3.9	0.1
Deferred income tax expense (4)	(4.4 )	1.6	(6.0 )	5.4	0.9	4.5	9.0	1.7	7.3
Equity earnings, net of distributions	-	-	-	(2.8 )	(2.8 )	-	-	-	-
Risk management activities (5)	4.7	4.7	-	(0.3 )	(0.5 )	0.2	3.6	5.3	(1.7 )
(Gain) loss on sale of assets	(4.8 )	(4.8 )	-	3.9	3.9	-	15.6	15.6	-
Loss on debt redemptions and amendments	12.4	12.4	-	14.7	14.7	-	12.8	12.8	-
Changes in operating assets and liabilities (6)	(50.7 )	(51.8 )	1.1	(144.5 )	(160.4 )	15.9	(9.4 )	4.4	(13.8 )
Net cash provided by (used in) operating activities	761.8	838.5	(76.7 )	382.7	411.4	(28.7 )	428.2	465.4	(37.2 )

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Cash flows from investing activities									
Outlays for property, plant and equipment (3)	(762.2 )	(762.2 )	-	(1,013.6)	(1,013.6)	-	(582.7 )	(582.3 )	(0.4 )
Business acquisitions, net of cash acquired	-	-	-	-	-	-	(996.2 )	(996.2 )	-
Purchase of materials and supplies	-	-	-	(17.7 )	(17.7 )	-	-	-	-
Investment in unconsolidated affiliate	-	-	-	-	-	-	(16.8 )	(16.8 )	-
Return of capital from unconsolidated affiliate	5.7	5.7	-	-	-	-	0.5	0.5	-
Other, net	5.1	5.1	-	5.0	5.0	-	4.5	1.0	3.5
Net cash used in investing activities	(751.4 )	(751.4 )	-	(1,026.3)	(1,026.3)	-	(1,590.7)	(1,593.8)	3.1
Cash flows from financing activities									
Loan Facilities - Partnership:									
Borrowings	2,400.0	2,400.0	-	2,238.0	2,238.0	-	2,595.0	2,595.0	-
Repayments	(2,254.8)	(2,254.8)	-	(2,021.2)	(2,021.2)	-	(1,690.7)	(1,690.7)	-
Accounts receivable securitization facility - Partnership									
Borrowings	381.9	381.9	-	373.3	373.3	-	-	-	-
Repayments	(478.8 )	(478.8 )	-	(93.6 )	(93.6 )	-	-	-	-
Loan Facilities - Non-Partnership:									
Borrowings (1)	92.0	-	92.0	65.0	-	65.0	90.0	-	90.0
Repayments (1)	(74.0 )	-	(74.0 )	(63.0 )	-	(63.0 )	(96.8 )	-	(96.8)
Costs incurred in connection with financing arrangements	(14.3 )	(14.0 )	(0.3 )	(15.3 )	(15.3 )	-	(36.6 )	(35.7 )	(0.9 )
Proceeds from sale of common units of the Partnership, net (7)	412.7	420.4	(7.7 )	524.7	535.5	(10.8 )	514.0	575.0	(61.0)

Distributions to owners (8)	(341.4 )	(522.2 )	180.8	(274.4 )	(412.3 )	137.9	(211.5 )	(303.8 )	92.3
Dividends to common and common equivalent shareholders	(113.0 )	-	(113.0)	(87.8 )	-	(87.8 )	(62.2 )	-	(62.2)
Repurchase of common stock	(2.6 )	-	(2.6 )	(13.3 )	-	(13.3 )	(9.5 )	-	(9.5 )
Excess tax benefit from stock-based awards	1.0	-	1.0	1.6	-	1.6	1.3	-	1.3
Repurchase of common units	(4.8 )	(4.8 )	-	-	-	-	-	-	-
Contributions (distributions) (9)	-	-	-	-	-	-	-	1.0	(1.0 )
Net cash provided by (used in) financing activities	3.9	(72.3 )	76.2	634.0	604.4	29.6	1,093.0	1,140.8	(47.8)
Net change in cash and cash equivalents	14.3	14.8	(0.5 )	(9.6 )	(10.5 )	0.9	(69.5 )	12.4	(81.9)
Cash and cash equivalents, beginning of period	66.7	57.5	9.2	76.3	68.0	8.3	145.8	55.6	90.2
Cash and cash equivalents, end of period	\$81.0	\$72.3	\$8.7	\$66.7	\$57.5	\$9.2	\$76.3	\$68.0	\$8.3

The major Non-Partnership cash flow items relate to:

(1) Cash and non-cash activity related to TRC debt obligations.

(2) Compensation on TRC's equity grants.

(3) Cash and non-cash activity related to corporate administrative assets.

(4) TRC's federal and state income taxes.

(5) Non-cash OCI hedge realizations related to predecessor operations.

(6) See Balance Sheets – Partnership versus Non-Partnership for a description of the Non-Partnership operating assets and liabilities.

(7) Contributions to the Partnership to maintain 2% General Partner ownership and additional investments in the Partnership in 2012.

(8) Distributions received by TRC from the Partnership for its general partner interest, limited partner interest and IDRs.

(9) Other activity with the Partnership.

Table of Contents

## Consolidated Results of Operations

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

	2014	2013	2012	2014 vs. 2013	2013 vs. 2012		
	(\$ in millions, except operating statistics and price amounts)						
Revenues	\$8,616.5	\$6,314.7	\$5,679.0	\$2,301.8	36 %	\$635.7	11 %
Product purchases	7,046.9	5,137.2	4,672.3	1,909.7	37 %	464.9	10 %
Gross margin (1)	1,569.6	1,177.5	1,006.7	392.1	33 %	170.8	17 %
Operating expenses	433.1	376.3	313.1	56.8	15 %	63.2	20 %
Operating margin (2)	1,136.5	801.2	693.6	335.3	42 %	107.6	16 %
Depreciation and amortization expenses	351.0	271.9	197.6	79.1	29 %	74.3	38 %
General and administrative expenses	148.0	151.5	139.8	(3.5 )	2 %	11.7	8 %
Other operating (income) expenses	(3.0 )	9.6	19.9	(12.6 )	131 %	(10.3 )	52 %
Income from operations	640.5	368.2	336.3	272.3	74 %	31.9	9 %
Interest expense, net	(147.1 )	(134.1 )	(120.8 )	(13.0 )	10 %	(13.3 )	11 %
Equity earnings	18.0	14.8	1.9	3.2	22 %	12.9	NM
Gain (loss) on debt redemptions and amendments	(12.4 )	(14.7 )	(12.8 )	2.3	16 %	(1.9 )	15 %
Other income (expense)	(8.0 )	15.3	(8.4 )	(23.3 )	152 %	23.7	282 %
Income tax (expense) benefit	(68.0 )	(48.2 )	(36.9 )	(19.8 )	41 %	(11.3 )	31 %
Net income	423.0	201.3	159.3	221.7	110 %	42.0	26 %
Less: Net income attributable to noncontrolling interests	320.7	136.2	121.2	184.5	135 %	15.0	12 %
Net income available to common shareholders	\$102.3	\$65.1	\$38.1	\$37.2	57 %	\$27.0	71 %
Operating statistics:							
Crude oil gathered, MBbl/d	93.5	46.9	-	46.6	99 %	46.9	-
Plant natural gas inlet, MMcf/d (3) (4)	2,109.5	2,110.2	2,098.3	(0.7 )	0 %	11.9	1 %
Gross NGL production, MBbl/d	153.0	136.8	128.7	16.2	12 %	8.1	6 %
Export volumes, MBbl/d (5)	176.9	66.6	31.6	110.3	166 %	35.0	111 %
Natural gas sales, BBtu/d (4)	902.3	928.2	927.6	(25.9 )	3 %	0.6	-
NGL sales, MBbl/d	419.5	294.8	267.9	124.7	42 %	26.9	10 %
Condensate sales, MBbl/d	4.4	3.5	3.5	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 the Partnership’s 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 the Partnership’s Operations”.

(3) 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.

(4) Plant natural gas inlet volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.

(5) 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.

2014 Compared to 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 planned 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.

Table of Contents

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 on debt redemptions and amendments reflect premiums paid and the write-off of associated unamortized debt issue costs related to the redemptions of our 7 % Notes in 2014 and the outstanding balance of the 11¼% Notes and \$100 million of our 6 % 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 the contingent consideration liability associated with the Badlands acquisition.

The increase in earnings attributable to noncontrolling interests is primarily due to higher Partnership earnings and higher earnings from the Partnership's joint ventures.

2013 Compared to 2012

Higher revenues, including the impact of hedging (a \$19.7 million decrease to revenues), were primarily due to the impact of higher commodity volumes (\$373.9 million), higher realized prices on natural gas, condensate, and petroleum products (\$261.2 million) and higher fee-based and other revenues (\$234.4 million), offset by lower realized prices on NGLs (\$225.1 million).

Higher gross margin in 2013 includes the contribution of the Partnership's Badlands acquisition. Other favorable gross margin factors were increased volumes from system expansions and higher gas prices in the Partnership's Field Gathering and Processing segment and higher fractionation fees and increased export activities in the Partnership's Logistics and Marketing segments. This significant growth in the Partnership's asset base brought a higher level of operating expenses in 2013. See "—Results of Operations—By Reportable Segment" for additional information regarding changes in the components of gross and operating margin on a disaggregated basis.

The increase in depreciation and amortization expenses was primarily due to tangible and intangible assets acquired in the Badlands acquisition and the timing of major organic investments placed in service including CBF Train 4, Phase I of the international export expansion project, and Badlands continuing development.

Higher general and administrative expenses reflected increased non-cash Long Term Incentive-Plan valuation expenses and increased expenses and compensation related costs to support the Partnership's expanding business operations.

Other operating expense in 2013 includes the loss due to a fire at the Saunders plant. Other operating expense in 2012 reflects a \$15.4 million loss due to a write-off of the Partnership's investment in the Yscloskey joint venture processing plant. Following Hurricane Isaac, the joint venture owners elected not to restart the plant. Additionally, other operating (income) expense in 2012 includes \$3.6 million in costs associated with the clean-up and repairs necessitated by Hurricane Isaac at the Partnership's Coastal Straddle plants.

The increase in interest expense primarily reflects higher borrowings, partially offset by the impact of lower effective interest rates and increases in capitalized interest attributable to our major expansion projects.

The increase in equity earnings relates to the Partnership's investment in GCF, which was profitable in 2013 compared to a loss in 2012 due to a planned shutdown of operations during the expansion of the facility.

Table of Contents

Losses on debt redemptions and amendments during 2013 are attributable to premiums paid and write-off of debt issue costs in connection with the redemption of the outstanding balance of the Partnership's 11¼% Notes and the redemption of \$100 million of the Partnership's 6 % Notes.

The increase in other income was attributable to the elimination of the contingent consideration associated with the Badlands acquisition, reflecting management's assessment that the stipulated volumetric thresholds were not met.

The increase in earnings attributable to noncontrolling interests is primarily due to higher Partnership earnings. Additionally, net income attributable to noncontrolling interests was \$3.5 million lower due to decreased net income of Versado and VESCO, partially offset by increased net income at CBF.

## Results of Operations—By Reportable Segment

We have segregated the following segment operating margins between Partnership and TRC Non-Partnership activities. Partnership activities have been presented on a common control accounting basis, which reflects the dropdown transactions between Targa and the Partnership as if they occurred in prior periods. TRC Non-Partnership segment results include certain assets and liabilities contractually excluded from the dropdown transactions and certain historical hedge activities that could not be reflected as such under GAAP in the Partnership common control results. See “—Financial Information – Partnership Versus Non-Partnership.”

	Partnership		Logistics Assets	Marketing and Distribution	Other	TRC Non- Partnership	Consolidated Operating Margin
	Field Gathering and Processing	Coastal Gathering and Processing					
	(In millions)						
2014	\$372.3	\$ 77.6	\$ 445.1	\$ 249.6	\$(8.0)	\$ (0.1)	) \$ 1,136.5
2013	270.5	85.4	282.3	141.9	21.4	(0.3)	) 801.2
2012	231.2	115.1	188.3	116.0	41.1	1.9	) 693.6

Table of Contents

## Results of Operations of the Partnership – By Reportable Segment

## Gathering and Processing Segments

## Field Gathering and Processing

	2014	2013	2012	2014 vs. 2013	2013 vs. 2012		
	(\$ in millions)						
Gross margin	\$563.2	\$435.7	\$357.4	\$127.5	29%	\$78.3	22%
Operating expenses	190.9	165.2	126.2	25.7	16%	39.0	31%
Operating margin	\$372.3	\$270.5	\$231.2	\$101.8	38%	\$39.3	17%
Operating statistics (1):							
Plant natural gas inlet, MMcf/d (2),(3)							
Sand Hills	165.1	155.8	145.2	9.3	6 %	10.6	7 %
SAOU (4)	193.1	154.1	124.8	39.0	25%	29.3	23%
North Texas System (5)	354.5	292.4	244.5	62.1	21%	47.9	20%
Versado	169.6	156.4	167.4	13.2	8 %	(11.0)	7 %
Badlands (6)	38.9	21.4	-	17.5	82%	21.4	-
	921.2	780.1	681.9	141.1	18%	98.2	14%
Gross NGL production, MBbl/d (3)							
Sand Hills	18.0	17.5	16.9	0.5	3 %	0.6	4 %
SAOU	25.2	22.5	19.2	2.7	12%	3.3	17%
North Texas System	37.8	31.1	26.8	6.7	22%	4.3	16%
Versado	21.4	18.9	19.7	2.5	13%	(0.8 )	4 %
Badlands	3.5	1.9	-	1.6	84%	1.9	-
	105.9	91.9	82.6	14.0	15%	9.3	11%
Crude oil gathered, MBbl/d	93.5	46.9	-	46.6	99%	46.9	-
Natural gas sales, BBtu/d (3)	469.0	376.3	325.0	92.7	25%	51.3	16%
NGL sales, MBbl/d	80.7	71.4	68.5	9.3	13%	2.9	4 %
Condensate sales, MBbl/d	3.6	3.2	3.2	0.4	13%	-	-
Average realized prices (7):							
Natural gas, \$/MMBtu	4.05	3.44	2.60	0.61	18%	0.84	32%
NGL, \$/gal	0.72	0.76	0.87	(0.04 )	5 %	(0.11)	13%
Condensate, \$/Bbl	82.35	92.89	88.49	(10.54)	11%	4.40	5 %

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

(1) 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.

(4) Includes volumes from the 200 MMcf/d cryogenic High Plains plant which started commercial operations in June 2014.

(5) Includes volumes from the 200 MMcf/d cryogenic Longhorn plant which started commercial operations in May 2014.

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

(7) Average realized prices exclude the impact of hedging settlements presented in Other.

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.

86

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Table of Contents

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.

2013 Compared to 2012

The increase in gross margin was primarily due to the inclusion of Badlands operations in 2013, higher overall throughput volumes and higher natural gas and condensate sales prices partially offset by lower NGL sales prices. The increase in plant inlet volumes was largely attributable to new well connects which increased available supply across each of our areas of operations, offset by the Saunders fire at Versado and by other operational issues and severe cold weather.

The increase in operating expenses was primarily due to the inclusion of Badlands operations in 2013 and additional compression and system maintenance related expenses attributable to increased volumes across our business and system expansions.

Coastal Gathering and Processing

	2014	2013	2012	2014 vs. 2013	2013 vs. 2012		
	(\$ in millions)						
Gross margin	\$123.8	\$132.3	\$162.2	\$(8.5 )	6 %	\$(29.9 )	18 %
Operating expenses	46.2	46.9	47.1	(0.7 )	1 %	(0.2 )	0 %
Operating margin	\$77.6	\$85.4	\$115.1	\$(7.8 )	9 %	\$(29.7 )	26 %
Operating statistics (1):							
Plant natural gas inlet, MMcf/d (2),(3)							
LOU	284.6	350.9	260.6	(66.3 )	19 %	90.3	35 %
VESCO	509.0	515.5	479.6	(6.5 )	1 %	35.9	7 %
Other Coastal Straddles	394.8	463.7	676.2	(68.9 )	15 %	(212.5)	31 %
	1,188.4	1,330.1	1,416.4	(141.7)	11 %	(86.3 )	6 %
Gross NGL production, MBbl/d (3)							
LOU	9.0	10.2	8.6	(1.2 )	12 %	1.6	19 %
VESCO	26.0	21.5	22.1	4.5	21 %	(0.6 )	3 %
Other Coastal Straddles	12.1	13.2	15.4	(1.1 )	8 %	(2.2 )	14 %
	47.1	44.9	46.1	2.2	5 %	(1.2 )	3 %
Natural gas sales, BBtu/d (3)	258.0	296.0	298.5	(38.0 )	13 %	(2.5 )	1 %
NGL sales, MBbl/d	40.2	41.8	42.5	(1.6 )	4 %	(0.7 )	2 %
Condensate sales, MBbl/d	0.7	0.4	0.3	0.3	75 %	0.1	33 %
Average realized prices:							
Natural gas, \$/MMBtu	4.44	3.73	2.78	0.71	19 %	0.95	34 %
NGL, \$/gal	0.80	0.83	0.96	(0.03 )	4 %	(0.13 )	14 %
Condensate, \$/Bbl	89.70	104.38	103.57	(14.68)	14 %	0.81	1 %

Segment operating statistics include intersegment amounts, which have been eliminated from the consolidated (1) 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.

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.

87

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Table of Contents

Operating expenses were relatively flat.

## 2013 Compared to 2012

The decrease in gross margin was primarily due to lower NGL prices, less favorable frac spreads and lower throughput volumes at VESCO and the Other Coastal Straddles. The decrease in plant inlet volumes was largely attributable to the decline in offshore and off-system supply volumes and the impact of the Yscloskey, Calumet and other third-party plant shutdowns. In addition, volumes were constrained by operational issues at VESCO and LOU. This volume decrease was partially offset by the addition of the Big Lake plant in the third quarter 2012 and a full-year of operations in 2013 as some of the Coastal Straddle plants were not operational in 2012 after Hurricane Isaac. Operational issues at VESCO included the impact of damage to one of the two third-party pipelines that provide NGL takeaway capacity for VESCO which constrained NGL production until repairs were completed in June 2013.

Operating expenses were relatively flat.

## Logistics and Marketing Segments

## Logistics Assets

	2014	2013	2012	2014 vs. 2013	2013 vs. 2012		
	(\$ in millions)						
Gross margin (1)	\$613.3	\$408.2	\$286.0	\$205.1	50%	\$122.2	43%
Operating expenses (1)	168.2	125.9	97.7	42.3	34%	28.2	29%
Operating margin	\$445.1	\$282.3	\$188.3	\$162.8	58%	\$94.0	50%
Operating statistics MBbl/d(2):							
Fractionation volumes (3)	350.0	287.6	299.2	62.4	22%	(11.6)	4%
LSNG treating volumes	23.4	20.1	22.4	3.3	16%	(2.3)	10%
Benzene treating volumes	23.4	17.5	19.0	5.9	34%	(1.5)	8%

Fractionation and treating contracts include pricing terms composed of base fees and fuel and power components (1) 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.

Segment operating statistics include intersegment amounts, which have been eliminated from the consolidated (2) 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.

## 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.

#### 2013 Compared to 2012

Gross margin increased primarily due to fractionation operations and LPG export activity. The lower year-to-date 2013 fractionation volumes were due to the planned maintenance turnaround at the Cedar Bayou Facility, ethane rejection at certain gas processing plants and pipeline operating issues at Non-Partnership facilities. Improvements in 2013 resulted from higher fractionation fees, CBF Train 4 which commenced commercial operations during the third quarter of 2013 and higher contractual capacity reservation fees. Gross margin results also include the impact of higher pass-through fuel costs. LPG export volumes, which benefit both the Logistics Assets and Marketing and Distribution segments, averaged 67 MBbl/d in 2013, compared to 32 MBbl/d for the previous year. The higher volumes reflect a significant increase in ongoing LPG export activity primarily due to our international export expansion project, which was placed into service in September 2013. Terminaling rates per unit volume were also higher and storage revenues increased due to increased rates and new customers. Gross margin for 2013 also benefitted from the renewable fuels project in our Petroleum Logistics business.

Table of Contents

The increase in operating expenses primarily reflects increased power and fuel prices; expenses related to the start-up and operations of Train 4 at CBF and increased maintenance costs, partially offset by higher system product gains.

## Marketing and Distribution

	2014	2013	2012	2014 vs. 2013	2013 vs. 2012		
	(\$ in millions)						
Gross margin	\$298.0	\$185.2	\$154.1	\$112.8	61%	\$31.1	20%
Operating expenses	48.4	43.3	38.1	5.1	12%	5.2	14%
Operating margin	\$249.6	\$141.9	\$116.0	\$107.7	76%	\$25.9	22%
Operating statistics (1):							
NGL sales, MBbl/d	423.3	296.6	273.2	126.7	43%	23.4	9%
Average realized prices:							
NGL realized price, \$/gal	0.93	0.94	0.98	(0.1)	1%	(0.04)	4%

Segment operating statistics include intersegment amounts, which have been eliminated from the consolidated (1) 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.

## 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 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.

## 2013 Compared to 2012

Gross margin increased primarily due to significantly higher terminaling fees from LPG export activity (which benefit both the Logistics Assets and Marketing and Distribution segments). The favorable impacts of higher barge and wholesale terminal utilization and higher wholesale margins were offset by lower natural gas marketing processing opportunities during 2013.

Operating expenses increased primarily due to higher barge and truck utilization and increased terminal operating costs.

## Other

	2014	2013	2012	2014 vs. 2013	2013 vs. 2012
	(\$ in millions)				
Gross margin	\$(8.0)	\$21.4	\$41.1	\$(29.4)	\$(19.7)
Operating margin	\$(8.0)	\$21.4	\$41.1	\$(29.4)	\$(19.7)

Other contains the financial effects of the Partnership's hedging program on operating margin as it represents the cash settlements on derivative hedge contracts and mark-to-market gains and losses on its derivative contracts not designated as hedges. The primary purpose of the commodity risk management activities is to mitigate a portion of the impact of commodity prices on the Partnership's operating cash flow. The Partnership has hedged the commodity price associated with a portion of its 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 their percent of proceeds or liquids processing arrangements by entering into derivative instruments. Because the Partnership is essentially forward-selling a portion of its plant equity volumes, these hedge positions will move favorably in periods of falling commodity prices and unfavorably in periods of rising commodity prices.

Table of Contents

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

	2014			2013			2012		
	(In millions, except volumetric data and price amounts)								
	Volume Settled	Price Spread (1)(2)	Gain (Loss)	Volume Settled	Price Spread (1)(2)	Gain (Loss)	Volume Settled	Price Spread (1)(2)	Gain (Loss)
Natural Gas (BBtu)	21.9	\$ (0.27 )	\$ (5.9 )	12.3	\$ 0.95	\$ 11.7	11.6	\$ 2.91	\$ 33.8
NGL (MMBbl)	0.6	5.79	3.6	2.1	6.19	12.8	2.6	3.50	9.1
Crude Oil (MMBbl)	0.9	(1.07 )	(1.0 )	0.7	(4.01 )	(2.9 )	0.6	(2.52 )	(1.4 )
Non-Hedge Accounting (3)			(4.8 )			(0.3 )			(0.3 )
Ineffectiveness (4)			0.1			0.1			(0.1 )
			\$ (8.0 )			\$ 21.4			\$ 41.1

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

(2) Price spread on Natural Gas volumes is \$/MMBtu, NGL volumes is \$/Bbl and Crude Oil volumes is \$/Bbl.

(3) Mark-to-market income (loss) associated with derivative contracts that are not designated as hedges for accounting purposes.

(4) Ineffectiveness primarily relates to certain crude hedging contracts.

#### Our Liquidity and Capital Resources

We have no separate, direct operating activities apart from those conducted by the Partnership. As such, our ability to finance our operations, including payment of dividends to our common stockholders, funding capital expenditures and acquisitions, or to meet our indebtedness obligations, will depend on cash inflows from future cash distributions to us from our interests in the Partnership. The Partnership is required to distribute all available cash at the end of each quarter after establishing reserves to provide for the proper conduct of its business or to provide for future distributions. See "Part I – Item 1A. Risk Factors." As of December 31, 2014, our interests in the Partnership consisted of the following:

a 2% general partner interest, which we hold through our 100% ownership interest in the general partner of the Partnership;

all of the outstanding IDRs; and

12,945,659 of the 118,586,056 outstanding common units of the Partnership, representing a 10.9% limited partnership interest.

Our future cash flows will consist of distributions to us from our interests in the Partnership. These cash distributions to us should provide sufficient resources to fund our operations, long-term debt obligations and tax obligations for at least the next twelve months. Based on the anticipated levels of distributions from the Partnership that we expect to receive, we also expect that we will be able to fund the projected quarterly cash dividends to our stockholders for the next twelve months.

The impact on us of changes in the Partnership's distribution levels will vary depending on several factors, including the Partnership's total outstanding partnership interests on the record date for the distribution, the aggregate cash distributions made by the Partnership and the interests in the Partnership owned by us. If the Partnership increases distributions to its unitholders, including us, we would expect to increase dividends to our stockholders, although the

timing and amount of such increased dividends, if any, will not necessarily be comparable to the timing and amount of the increase in distributions made by the Partnership. In addition, the level of distributions we receive and of dividends we pay to our stockholders may be affected by the various risks associated with an investment in us and the underlying business of the Partnership. Please read “Part I – Item 1A. Risk Factors” for more information about the risks that may impact your investment in us.

Table of Contents

Our liquidity as of January 31, 2015 was:

	As of January 31, 2015 (In millions)
Cash on hand	\$ 15.0
Total availability under TRC's credit facility	150.0
TRC senior secured term loan	-
Less: Outstanding borrowings under TRC's credit facility	(108.0 )
Less: borrowings under TRC senior secured term loan	-
Total liquidity	\$ 57.0

### The Partnership's Liquidity and Capital Resources

The Partnership's ability to finance its operations, including funding capital expenditures and acquisitions, meeting its indebtedness obligations, refinancing its indebtedness and meeting its collateral requirements, will depend on its ability to generate cash in the future. The Partnership's ability to generate cash is subject to a number of factors, some of which are beyond its 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.

The Partnership's 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 common units and access to debt markets. The capital markets continue to experience volatility. The Partnership's exposure to current credit conditions includes its credit facilities, cash investments and counterparty performance risks. The Partnership continually monitors its liquidity and the credit markets, as well as events and circumstances surrounding each of the lenders to the TRP Revolver and Securitization Facility.

The Partnership's liquidity as of January 31, 2015 was:

	As of January 31, 2015 (In millions)
Cash on hand	\$ 1,110.3
Total availability under the TRP Revolver	1,200.0
Total availability under the Securitization Facility	236.2
	2,546.5
Less: Outstanding borrowings under the TRP Revolver	-
Outstanding borrowings under the Securitization Facility	-
Outstanding letters of credit under the TRP Revolver	(41.7 )
Total liquidity	\$ 2,504.8

Other potential capital resources include:

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The Partnership is in the process of seeking an Amendment to the TRP Revolver to increase the facility size to approximately \$1.6 billion from \$1.2 billion and will maintain the right to request an additional \$300 million in commitment increases. The amended TRP Revolver will continue to be due on October 3, 2017.

Approximately \$158.4 million in remaining capacity as of December 31, 2014 to issue common units pursuant to the May 2014 EDA (see Notes 10 and 11 of the “Consolidated Financial Statements”).

The Partnership’s ability to issue debt or equity securities pursuant to shelf registration statements, including availability under the Partnership’s July 2013 Shelf and unlimited amounts under the Partnership’s April 2013 Shelf.

## Table of Contents

A portion of the Partnership's capital resources may be allocated to letters of credit to satisfy certain counterparty credit requirements. While the Partnership's credit ratings have improved over time, these letters of credit reflect its non-investment grade status, as assigned to the Partnership by Moody's and S&P. They also reflect certain counterparties' views of its financial condition and ability to satisfy its performance obligations, as well as commodity prices and other factors.

### Pending Atlas Mergers

On October 13, 2014, we and the Partnership announced two proposed merger transactions which would result in the Partnership's acquisition of APL, a Delaware limited partnership, and our acquisition of ATLS, a Delaware limited partnership which owns the APL general partner. Upon consummation of these mergers, we would relinquish the APL general partner and IDR ownership interests and merge the APL general partner into the Partnership. Each of the Transactions is contingent on one another, and the Transactions are expected to close concurrently on February 28, 2015, subject to the approval of Targa's stock issuance in connection with the ATLS Merger by Targa's stockholders and the approval of the Atlas Mergers by unitholders of ATLS and APL, as applicable, and other customary closing conditions.

### APL Merger

As merger consideration for the APL Merger, holders of APL common units (other than certain common units held by the Partnership or APL or their wholly owned subsidiaries, which will be cancelled) will be entitled to receive 0.5846 of the Partnership's common units and a one-time cash payment of \$1.26 for each APL common unit. The Partnership will also redeem APL's Class E Preferred Units for an aggregate amount of \$126.5 million in cash. As of February 5, 2015, the total APL merger consideration would be valued at \$5.0 billion. The portion of the merger consideration represented by the Partnership's common units will fluctuate in value until the closing date as a result of fluctuations in the market price of its common units.

In connection with the APL Merger, Targa has agreed to reduce its incentive distribution rights for the four years following closing by fixed amounts of \$37.5 million, \$25.0 million, \$10.0 million and \$5.0 million, respectively. These annual amounts will be applied in equal quarterly installments for each successive four quarter period following closing.

### ATLS Merger

ATLS holds the general partner's interest in APL as well as Incentive Distribution Rights and 5.5% limited partner interest. Under the terms of the ATLS Merger, each existing holder of common units of ATLS, after giving effect to the spin-off of non-midstream assets, will be entitled to receive 0.1809 of our common shares and a cash payment of \$9.12 for each ATLS common unit, which equates to 10.35 million shares of our common stock and \$522 million in cash payments. Additionally, we will provide ATLS with \$88 million of cash for the repayment of a portion of the ATLS outstanding indebtedness and fund approximately \$190 million related to change of control payments payable by ATLS. As of February 5, 2015, the total ATLS merger consideration would be valued at \$1.6 billion. The portion of the merger consideration represented by our common shares will fluctuate in value until the closing date as a result of fluctuations in the market price of our common shares.

### Pre-Closing Merger Financing Activities

We have arranged committed financing of \$1.1 billion to replace our existing revolving credit facility and to fund the cash components of the ATLS Merger, including cash merger consideration and approximately \$190 million related to change of control payments payable by ATLS and transaction fees and expenses. In January 2015, as part of a new senior secured credit facility to syndicate the \$1.1 billion in committed financing, we announced the launch of a \$430

million senior secured term loan maturing 7 years after closing and a \$670 million revolving credit facility maturing 5 years after closing. These facilities are subject to the closing of the pending Atlas Mergers and market conditions.

In January 2015, S&P assigned a B+ corporate credit rating with a stable outlook to us and also assigned a B+ issue-level rating to our new senior secured credit facility. In January 2015, Moody's assigned a Ba3 corporate facility rating with a stable outlook to us and assigned the same rating to our new senior secured credit facility.

Table of Contents

Partnership Pre-Closing Merger Financing Activities

In January 2015, the Partnership commenced cash tender offers for any and all of the outstanding APL Senior Notes. These tender offers are in connection with, and conditioned upon, the consummation of the proposed merger with APL. The proposed merger with APL, however, is not conditioned on the consummation of the tender offers. Each tender offer is scheduled to expire on February 18, 2015, unless extended by the Partnership at its sole discretion.

Under the terms of the tender offer, APL noteholders will receive \$1,015 per \$1,000 principal if tendered before January 29, 2015 and \$985 per \$1,000 principal if tendered after that date. Holders of tendered APL Notes will also receive accrued and unpaid interest from the most recent interest payment date on their series of APL Notes.

The outstanding APL Senior Notes consist of:

APL Senior Notes	Amount tendered as of February 6, 2015
\$500 million 6 due 2020	Less than majority
\$400 million 4¾ due 2021	98.3%
\$650 million 5 % due 2023	91.6%

The consummation of the merger with APL will result in a Change of Control under the APL Indenture and obligate the APL Issuers to make a Change of Control Offer at \$1,010 for each \$1,000 principal plus accrued and unpaid interest from the most recent interest payment date. As permitted by the APL Indenture, the Partnership is making a Change of Control Offer for any and all of the 2020 APL Notes in lieu of the APL Issuers and in advance of, and conditioned upon, the consummation of the merger with APL. The merger, however, is not conditioned on the consummation of the Change of Control Offer. The Change of Control Offer is also being made independently of the Partnership's previously announced tender offer for the APL Notes. The Change of Control Offer is scheduled to expire on March 3, 2015, unless extended by the Partnership. Any 2020 APL Notes that remain outstanding after consummation of the Change of Control Offer will continue to be the obligation of the APL Issuers under the governing indenture.

In January 2015, the Partnership privately placed \$1.1 billion in aggregate principal amount of 5% Notes due 2018 (the "5% Notes"). The 5% Notes resulted in approximately \$1,090.8 million of net proceeds, which will be used together with borrowings from the TRP Revolver, to fund the APL Notes Tender Offers and the change of control offers for the APL Notes pursuant to the indentures governing the 2020 APL Notes the 2021 APL Notes and the 2023 APL Notes. The Partnership expects to finance the cash portion of the APL Merger with borrowings under the Partnership's Revolver.

In January 2015, Moody's assigned a Ba2 rating to the Partnership's 5% Notes. In addition, Moody's affirmed all of the Partnership's credit ratings but changed the Partnership's outlook from positive to stable.

Table of Contents

## Pro Forma Effect of Atlas Mergers on our Liquidity

The following table sets forth our liquidity as of January 31, 2015 on a historical basis; and on a pro forma as adjusted basis to give effect to the following Atlas Merger-related items: (i) the \$430 million senior secured term loan maturing 7 years after closing; (ii) the \$670 million revolving credit facility that will replace its existing \$150.0 million revolving credit facility; (iii) and the application of net proceeds to fund the cash merger consideration, change of control payments payable by ATLS and transaction fees and expenses.

	As of January 31, 2015	
	Historical	Pro Forma As Adjusted
	(In millions)	
Cash on hand	\$ 15.0	\$ 15.0
Total availability under TRC's credit facility	150.0	670.0
TRC senior secured term loan	-	430.0
Less: Outstanding borrowings under TRC's credit facility	(108.0)	(464.9 )
Less: borrowings under TRC senior secured term loan	-	(430.0 )
Total liquidity	\$ 57.0	\$ 220.1

## Pro Forma Effect of Atlas Mergers on the Partnership's Liquidity

The following table sets forth the Partnership's liquidity as of January 31, 2015 on a historical basis, which is inclusive of the net proceeds received on January 30, 2015 from the Partnership's private placement of the 5% Notes and on a pro forma as adjusted basis to give effect to following Atlas Merger-related items: (i) additional borrowings from the TRP Revolver and Securitization Facility; (ii) the application of net proceeds of the 5% Notes and additional borrowings from the TRP Revolver and Securitization Facility to fund the tender offers received and (iii) the application of net proceeds to fund the cash merger consideration, redemption of APL Class E preferred units, change of control payments payable by APL and transaction fees and expenses.

	As of January 31, 2015	
	Historical	Pro Forma As Adjusted
	(In millions)	
Cash on hand	\$ 1,110.3	\$ 74.2
Total availability under the TRP Revolver	1,200.0	1,200.0
Total availability under the Securitization Facility	236.2	236.2
	2,546.5	1,510.4
Less: Outstanding borrowings under the TRP Revolver	-	(631.5 )
Outstanding borrowings under the Securitization Facility	-	(236.2 )
Outstanding letters of credit under the TRP Revolver	(41.7 )	(41.7 )
Total liquidity	\$ 2,504.8	\$ 601.0

## 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 the Partnership's reported total working capital are: (1) the Partnership's cash position; (2) liquids inventory levels and valuation, which the Partnership closely manages; (3) changes in the fair value of the current portion of derivative contracts; and (4) major structural changes in the Partnership's asset base or business operations, such as acquisitions or divestitures and certain organic growth projects.

The Partnership's working capital increased \$110.8 million exclusive of the impact of current debt obligations. This non-debt increase was driven by an increase in the Partnership's net risk management working capital position due to changes in the forward prices of commodities, decreased capital spending due to the completion of 2013 projects, and increased NGL inventories. Higher inventory volumes are primarily due to the effects of our expanding export activities and an additional build in Wholesale field inventories to meet customer requirements. In addition, working capital was affected by the inclusion at December 31, 2014 of \$182.8 million related to the Securitization Facility.

Table of Contents

Based on the Partnership's 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 equity offerings and debt offerings should provide sufficient resources to finance its operations, capital expenditures, long-term debt obligations, collateral requirements, acquisition payments related to the Atlas Mergers and minimum quarterly cash distributions for at least the next twelve months.

The Non-Partnership working capital increased \$0.7 million primarily due to higher compensation and benefits partially offset by lower Federal income tax receivables for the year ended December 31, 2014.

We have incurred tax liabilities as a result of our sales of assets to the Partnership. We have sufficient liquidity to satisfy the \$48.8 million tax liability expected to be paid over the next 10 years.

Cash Flow

Cash Flow from Operating Activities

	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership	
	(In millions)			
2014	\$761.8	\$ 838.5	\$ (76.7	)
2013	382.7	411.4	(28.7	)
2012	428.2	465.4	(37.2	)

The Consolidated Statements of Cash Flows included in the 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 the 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 the Partnership versus Non-Partnership's operating cash flows using the direct method as a supplement to the presentation in the consolidated financial statements:

	2014			2013			2012		
	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC-Non Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC-Non Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC-Non Partnership
	(In millions)								
Cash flows from operating activities:									
Cash received from customers	\$8,769.4	\$8,769.5	\$ (0.1 )	\$6,388.0	\$6,388.3	\$ (0.3 )	\$5,948.7	\$5,948.9	\$ (0.2 )
Cash received from (paid to) derivative counterparties	(4.9 )	(4.9 )	-	20.9	20.9	-	47.3	47.3	-
Product purchases	7,268.5	7,268.5	-	5,364.8	5,364.8	-	4,973.1	4,972.9	0.2

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Operating expenses	402.6	402.5	0.1	377.4	377.3	0.1	339.9	339.6	0.3
General and administrative expenses	134.5	133.7	0.8	137.6	145.3	(7.7 )	121.1	117.8	3.3
Cash distributions from equity investment (1)	(18.0 )	(18.0 )	-	(12.0 )	(12.0 )	-	(1.8 )	(1.8 )	-
Interest paid, net of amounts capitalized (2)	133.8	131.0	2.8	121.7	119.1	2.6	95.5	92.5	3.0
Income taxes paid, net of refunds	73.4	2.7	70.7	35.7	2.3	33.4	31.8	2.2	29.6
Other cash (receipts) payments	7.9	5.7	2.2	1.0	1.0	-	8.2	7.6	0.6
Net cash provided by operating activities	\$761.8	\$838.5	\$(76.7 )	\$382.7	\$411.4	\$(28.7 )	\$428.2	\$465.4	\$(37.2 )

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Excludes \$5.7 million and \$0.5 million included in investing activities for the years ended 2014 and 2012 related to (1) distributions from GCF that exceeded cumulative equity earnings. GCF did not have distributions that exceeded cumulative equity earnings for 2013.

(2) Net of capitalized interest paid of \$16.1 million, \$28.0 million and \$13.6 million included in investing activities for the years ended 2014, 2013 and 2012.

Table of Contents

## Cash Flow from Operating Activities - Partnership

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 (\$2,381.2 million), as well as higher cash payments to producers for commodity products (\$1,903.7 million). The change in cash received related to derivatives reflects a net outflow of \$4.9 million in 2014 compared to a net inflow in 2013 of \$20.9 million due to the prices paid to counterparties compared to the fixed price the Partnership received on those derivative contracts. Lower cash general and administrative expenses were mainly due to the lower cash settlements on TRC long term incentive plan costs in 2014 versus 2013 (\$11.6 million). The increase in other cash payments during 2014 reflects transaction costs related to the ATLS Mergers (\$4.7 million).

Higher natural gas prices, higher plant throughput volumes and increased export activities contributed to increased cash collections in 2013 compared to 2012 (\$439.4 million). These factors also caused higher cash payments to producers and purchases of commodity products (\$391.9 million). The change in cash received related to derivatives reflects higher commodity prices paid to counterparties compared to the fixed price the Partnership received on those derivative contracts (\$26.4 million). The decrease in other cash payments during 2013 was mainly attributable to the fees related to the Badlands acquisition paid in 2012 (\$6.6 million).

## Cash Flow from Investing Activities

	Targa Resources Corp. Consolidated (In millions)	Targa Resources Partners LP (In millions)	TRC - Non-Partnership
2014	\$(751.4 )	\$(751.4 )	\$ -
2013	(1,026.3 )	(1,026.3 )	-
2012	(1,590.7 )	(1,593.8 )	3.1

## Cash Flow from Investing Activities - Partnership

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.

The decrease in net cash used in investing activities for 2013 compared to 2012 was primarily due to a decrease in outlays for business acquisitions of \$996.2 million and the absence of capital calls in 2013 at GCF (\$16.8 million in 2012), partially offset by an increase in current capital expansion projects of \$413.9 million and the purchase of material and supplies of \$17.7 million related to our Badlands expansion.

## Cash Flow from Financing Activities

	Targa Resources Corp. Consolidated (In millions)	Targa Resources Partners LP (In millions)	TRC - Non-Partnership
2014	\$3.9	\$(72.3 )	\$ 76.2
2013	634.0	604.4	29.6
2012	1,093.0	1,140.8	(47.8 )

Cash Flow from Financing Activities - Partnership

The decrease in net cash provided by financing activities for 2014 compared to 2013 was primarily due to lower net borrowings under the Partnership's 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).

Table of Contents

The decrease in net cash provided by financing activities for 2013 compared to 2012 was primarily due to a lower net borrowing under the TRP Revolver (\$347.0 million), lower issuance of Senior Notes (\$375.0 million) and an increase in distributions to owners (\$111.6 million), offset by higher net borrowings under the Securitization Facility (\$279.7 million).

**Cash Flow Financing Activities - Non-Partnership**

The increase in net cash provided by financing activities for 2014 compared to 2013 was primarily due to an increase in distributions received of \$42.9 million, an increase in net borrowings under TRC's senior secured revolving credit facility ("TRC Revolver") of \$16.0 million, partially offset by an increase in dividends paid of \$25.2 million.

Financing activities provided a net source of cash in 2013 compared to an outflow in 2012 primarily due to the purchase in 2012 of Partnership units for \$47.0 million and an increase in distributions received of \$45.6 million and an increase in borrowings on the TRC Revolver of \$8.8 million, partially offset by an increase in dividends paid of \$25.6 million.

**Capital Requirements**

The Partnership's capital requirements relate to capital expenditures, which are classified as expansion expenditures, maintenance expenditures or business acquisitions. 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 the Partnership's existing assets, including the replacement of system components and equipment, which are worn, obsolete or completing their useful life, and expenditures to remain in compliance with environmental laws and regulations. Non-Partnership currently does not have any capital expenditures.

	2014		2013		2012				
	Targa Resources Corp. Consolidated	Targa Resources Partners LP	Targa Resources Corp. Consolidated	Targa Resources Partners LP	Targa Resources Corp. Consolidated	Targa Resources Partners LP	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
	(In millions)								
Capital expenditures:									
Business acquisitions, net of cash acquired	\$-	\$-	\$-	\$-	\$-	\$-	\$996.2	\$996.2	\$-
Expansion (1)	668.7	668.7	-	954.6	954.6	-	540.7	540.7	-
Maintenance	79.1	79.1	-	79.9	79.9	-	76.3	76.0	0.3
Gross capital expenditures	747.8	747.8	-	1,034.5	1,034.5	-	1,613.2	1,612.9	0.3
Transfers from materials and supplies inventory to property, plant and equipment	(4.6 )	(4.6 )		(20.5 )	(20.5 )	-	-	-	-
Decrease (Increase) in capital project payables and accruals	19.0	19.0	-	(0.4 )	(0.4 )	-	(34.3 )	(34.4 )	0.1
Cash outlays for capital projects	\$762.2	\$762.2	\$-	\$1,013.6	\$1,013.6	\$-	\$1,578.9	\$1,578.5	\$0.4

Excludes cash calls to the Partnership's affiliate of \$16.8 million during 2012 to fund the GCF expansion project.  
(1) Cash calls are reflected in Investment in unconsolidated affiliate in cash flows from investing activities on our Consolidated Statements of Cash Flows in our "Consolidated Financial Statements."

The Partnership estimates that its total growth capital expenditures for 2015 will be approximately \$490 to \$675 million on a gross basis (exclusive of increased capital spending resulting from the pending APL merger). Given the Partnership's objective of growth through acquisitions, expansions of existing assets and other internal growth projects, it anticipates that over time that it will invest significant amounts of capital to grow and acquire assets. Future expansion capital expenditures may vary significantly based on investment opportunities. The Partnership expects to fund future capital expenditures with funds generated from its 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 2015 are discussed in "Item 1. Business-Organic Growth Projects."

Table of Contents

## Credit Facilities and Long-Term Debt

The following table summarizes our debt obligations as of December 31, 2014 (in millions):

## Current:

## Partnership

Accounts receivable securitization facility, due December 2015	\$182.8
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## Long-term:

## Non-Partnership Obligations:

TRC Senior secured revolving credit facility due October 2017	102.0
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## Partnership Obligations:

Senior secured revolving credit facility, due October 2017	-
Senior unsecured notes, 6 % fixed rate, due July 2021	483.6
Unamortized discount	(25.2 )
Senior unsecured notes, 6 % fixed rate, due August 2022	300.0
Senior unsecured notes, 5¼% fixed rate, due May 2023	600.0
Senior unsecured notes, 4¼% fixed rate, due November 2023	625.0
Senior unsecured notes, 4 % fixed rate, due November 2019	800.0
Total long-term debt	2,885.4
Total Debt	\$3,068.2

We consolidate the debt of the Partnership with that of our own; however, we do not have the contractual obligation to make interest or principal payments with respect to the debt of the Partnership. Our debt obligations do not restrict the ability of the Partnership to make distributions to us. TRC's Credit Agreement has restrictions and covenants that may limit our ability to pay dividends to our stockholders. See Note 10 of the "Consolidated Financial Statements" beginning on page F-1 of this Annual Report for more information of the restrictions and covenants in TRC's Credit Agreement.

## Compliance with Debt Covenants

As of December 31, 2014, both we and the Partnership were in compliance with the covenants contained in our various debt agreements.

## TRC Revolving Credit Agreement

In October 2012, we entered into a Credit Agreement that replaced our variable rate Senior Secured Revolving Credit Facility due July 2014 with a new variable rate Senior Secured Credit Facility due October 3, 2017 (the "TRC Revolver"). The TRC Revolver increases available commitments to \$150.0 million from \$75.0 million, allows us to request up to an additional \$100.0 million in commitment increases and includes a \$30.0 million swing line sub-facility. Outstanding letters of credit and related outstanding reimbursement obligations may not exceed \$50.0 million in the aggregate.

In 2012, we incurred a charge of \$0.2 million related to a partial write-off of debt issue costs associated with the previous credit facility as a result of a change in syndicate members under the new TRC Revolver. The remaining deferred debt issue costs along with the issue costs associated with the October 2012 amendment are amortized on a straight-line basis over the life of the TRC Revolver.

The TRC Revolver bears interest, at our option, at either (a) a base rate equal to the highest of the prime rate of Deutsche Bank Trust Company Americas, the administrative agent, the federal funds rate plus 0.5% and the one-month LIBOR rate plus 1.0%, plus an applicable margin ranging from 1.75% to 2.5% (dependent upon the

Company's consolidated leverage ratio), or (b) the LIBOR rate plus an applicable margin ranging from 2.75% to 3.5% (dependent upon the Company's consolidated leverage ratio).

We are required to pay a commitment fee ranging from 0.375% to 0.5% (dependent upon the Company's consolidated leverage ratio) on the daily average unused portion of the TRC Revolver. Additionally, issued and undrawn letters of credit bear interest at an applicable ranging from 2.75% to 3.5% (dependent upon the Company's consolidated leverage ratio).

## Table of Contents

The TRC Revolver is secured by substantially all of the Company's assets. The TRC Revolver requires us to maintain a consolidated leverage ratio (the ratio of consolidated funded indebtedness to consolidated adjusted EBITDA) of no more than 4.00 to 1.00. The TRC Revolver restricts our ability to make dividends to shareholders if, on a pro forma basis after giving effect to such dividend, (a) any default or event of default has occurred and is continuing or (b) our consolidated leverage ratio exceeds 4.00 to 1.00. In addition, the TRC Revolver includes various covenants that may limit, among other things, our ability to incur indebtedness, grant liens, make investments, repay or amend the terms of certain other indebtedness, merge or consolidate, sell assets, and engage in transactions with affiliates.

### The Partnership's Revolving Credit Agreement

In October 2012, the Partnership entered into a Second Amended and Restated Credit Agreement that amended and replaced its variable rate Senior Secured Revolving Credit Facility due July 2015 with the variable rate TRP Revolver. The TRP Revolver increased available commitments to \$1.2 billion from \$1.1 billion and allows the Partnership to request up to an additional \$300.0 million in commitment increases.

In 2012, the Partnership incurred a \$1.7 million loss related to a partial write-off of debt issue costs associated with the previous credit facility as a result of a change in syndicate members under the new TRP Revolver. The remaining deferred debt issue costs along with the issue costs associated with the October 2012 amendment are amortized on a straight-line basis over the life of the TRP Revolver.

The TRP Revolver bears interest, at the Partnership's option, either at the base rate or the Eurodollar rate. The base rate is equal to the highest of: (i) Bank of America's prime rate; (ii) the federal funds rate plus 0.5%; or (iii) the one-month LIBOR rate plus 1.0%, plus an applicable margin ranging from 0.75% to 1.75% (dependent on the Partnership's ratio of consolidated funded indebtedness to consolidated adjusted EBITDA). The Eurodollar rate is equal to LIBOR rate plus an applicable margin ranging from 1.75% to 2.75% (dependent on the Partnership's ratio of consolidated funded indebtedness to consolidated adjusted EBITDA).

The Partnership is required to pay a commitment fee equal to an applicable rate ranging from 0.3% to 0.5% (dependent on the Partnership's ratio of consolidated funded indebtedness to consolidated adjusted EBITDA) times the actual daily average unused portion of the TRP Revolver. Additionally, issued and undrawn letters of credit bear interest at an applicable rate ranging from 1.75% to 2.75% (dependent on the Partnership's ratio of consolidated funded indebtedness to consolidated adjusted EBITDA).

The TRP Revolver is collateralized by a majority of the Partnership's assets. Borrowings are guaranteed by the Partnership's restricted subsidiaries.

The TRP Revolver restricts the Partnership's ability to make distributions of available cash to unitholders if a default or an event of default (as defined in the TRP Revolver) exists or would result from such distribution. The TRP Revolver requires the Partnership to maintain a ratio of consolidated funded indebtedness to consolidated adjusted EBITDA of no more than 5.50 to 1.00. The TRP Revolver also requires the Partnership to maintain a ratio of consolidated EBITDA to consolidated interest expense of no less than 2.25 to 1.00. In addition, the TRP Revolver contains various covenants that may limit, among other things, the Partnership's ability to incur indebtedness, grant liens, make investments, repay or amend the terms of certain other indebtedness, merge or consolidate, sell assets, and engage in transactions with affiliates (in each case, subject to the Partnership's right to incur indebtedness or grant liens in connection with, and convey accounts receivable as part of, a permitted receivables financing).

### The Partnership's Senior Unsecured Notes

In January 2012, the Partnership privately placed \$400.0 million in aggregate principal amount of its 6 % Notes, resulting in approximately \$395.5 million of net proceeds, which were used to reduce borrowings under the TRP

Revolver and for general partnership purposes.

In October 2012, \$400.0 million in aggregate principal amount of 5¼% Notes were issued by the Partnership at 99.5% of the face amount, resulting in gross proceeds of \$398.0 million. An additional \$200.0 million in aggregate principal amount of 5¼% Notes were issued in December 2012 at 101.0% of the face amount, resulting in gross proceeds of \$202.0 million. Both issuances are treated as a single class of debt securities and have identical terms.

99

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Table of Contents

In November 2012, the Partnership redeemed all of the outstanding 8¼% Notes at a redemption price of 104.125% plus accrued interest through the redemption date. The redemption resulted in a premium paid on the redemption of \$8.6 million, which is included as a cash outflow from financing activities in the Consolidated Statements of Cash Flows, and a write off of \$2.5 million of unamortized debt issue costs.

In May 2013, the Partnership 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, the Partnership paid \$106.4 million plus accrued interest, which included a premium of \$6.4 million, to redeem \$100.0 million of the outstanding 6 % Notes. The redemption resulted in a \$7.4 million loss on debt redemption, including the write-off of \$1.0 million of unamortized debt issue costs.

In July 2013, the Partnership 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 issue costs.

In October 2014, the Partnership privately placed \$800.0 million in aggregate principal amount of 4 % Senior Notes due 2019 (the "4 % Notes"). The 4 % 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, the Partnership redeemed the outstanding 7 % 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 issue costs.

The terms of the senior unsecured notes outstanding as of December 31, 2014 were as follows:

Note Issue	Issue Date	Per Annum Interest Rate	Due Date	Dates Interest Paid
"6 % Notes"	February 2011	6 %	February 1, 2021	February & August 1 <sup>st</sup>
"6 % Notes"	January 2012	6 %	August 1, 2022	February & August 1 <sup>st</sup>
"5¼% Notes"	Oct / Dec 2012	5¼%	May 1, 2023	May & November 1 <sup>st</sup>
"4¼% Notes"	May 2013	4¼%	November 15, 2023	May & November 15 <sup>th</sup>
"4 % Notes"	October 2014	4 %	November 15, 2019	May & November 15 <sup>th</sup>

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 the Partnership's future subordinated indebtedness and are unconditionally guaranteed by the Partnership. These notes are effectively subordinated to all secured indebtedness under the TRP Revolver, which is secured by a majority of its assets and the Partnership's 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.

The Partnership's senior unsecured notes and associated indenture agreements restrict its ability to make distributions to unitholders in the event of default (as defined in the indentures). The indentures also restrict the Partnership's ability and the ability of certain of the Partnership's 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 both Moody's and S&P (or rated investment grade by either Moody's or S&P for the 6 % Notes, 5¼% Notes, 4¼% Notes and 4 % 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.

100

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Table of Contents

## Accounts Receivable Securitization Facility

The Securitization Facility provides up to \$300.0 million of borrowing capacity at LIBOR market index rates plus a margin through December 11, 2015. Under the Securitization Facility, two of the Partnership's consolidated subsidiaries (Targa Liquids Marketing and Trade LLC ("TLMT") and Targa Gas Marketing LLC ("TGM")) sell or contribute receivables, without recourse, to another of its consolidated subsidiaries (Targa Receivables LLC or "TRLCC"), a special purpose consolidated subsidiary created for the sole purpose of the Securitization Facility. TRLCC, 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, TGM or the Partnership. Any excess receivables are eligible to satisfy the claims of creditors of TLMT, TGM or the Partnership. As of December 31, 2014, total funding under the Securitization Facility was \$182.8 million.

## Off-Balance Sheet Arrangements

We currently have no off-balance sheet arrangements as defined by the SEC. See "Contractual Obligations" below and "Commitments (Leases)" included in Note 17 of our "Consolidated Financial Statements" beginning on page F-1 of this Annual Report for a discussion of our commitments and contingencies.

## Contractual Obligations

In addition to disclosures related to debt and lease obligations, contained in Notes 10 and 16 of the "Consolidated Financial Statements" beginning on page F-1 of this Annual Report, the following is a summary of certain contractual obligations over the next several years:

Contractual Obligations	Total	Payments Due By Period			More Than 5 Years
		Less Than 1 Year	1-3 Years	3-5 Years	
(In millions, except volumetric information)					
Non-Partnership Obligations:					
Debt obligations (1)	\$ 102.0	\$ -	\$ 102.0	\$ -	\$ -
Interest on debt obligations (2)	13.2	3.0	5.9	4.3	-
Operating leases (3)	7.6				