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, 2013

or

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

For the transition period from _____ to _____

Commission File Number: 001-33303

TARGA RESOURCES PARTNERS LP

(Exact name of registrant as specified in its charter)

Delaware	**65-1295427**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
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 Units Representing Limited Partnership Interests	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 £

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 R 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 R	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 R.

The aggregate market value of the common units representing limited partner interests held by non-affiliates of the registrant was approximately $4,678.1 million on June 28, 2013, based on $50.45 per unit, the closing price of the common units as reported on the New York Stock Exchange (NYSE) on such date.

As of February 10, 2014, there were 112,390,094 common units and 2,293,677 general partner units outstanding.

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CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

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

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

These forward-looking statements reflect our intentions, plans, expectations, assumptions and beliefs about future events and are subject to risks, uncertainties and other factors, many of which are outside our control. Important factors that could cause actual results to differ materially from the expectations expressed or implied in the forward-looking statements include known and unknown risks. Known risks and uncertainties include, but are not limited to, the risks set forth in "Part I, Item 1A. Risk Factors." of this Annual Report on Form 10-K ("Annual Report") as well as the following risks and uncertainties:

- 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 our transactions;

- our success in risk management activities, including the use of derivative instruments to hedge commodity risks;

- the level of creditworthiness of counterparties to various transactions;

- changes in laws and regulations, particularly with regard to taxes, safety and protection of the environment;

- the timing and extent of changes in natural gas, natural gas liquids ("NGL"), crude oil and other commodity prices, interest rates and demand for our services;

- weather and other natural phenomena;

- industry changes, including the impact of consolidations and changes in competition;

- our ability to obtain necessary licenses, permits and other approvals;

- the level and success of crude oil and natural gas drilling around our assets, our success in connecting natural gas supplies to our gathering and processing systems, oil supplies to our gathering systems and NGL supplies to our logistics and marketing facilities and our success in connecting our facilities to transportation and markets;

- our ability to grow through acquisitions or internal growth projects and the successful integration and future performance of such assets;

- general economic, market and business conditions; and

- the risks described elsewhere in "Part I, 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 "Part I, 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

PART I

Item 1. Business.

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

We are engaged in the business of:

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

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

Our midstream natural gas and NGL services footprint was initially established through several acquisitions from Targa, totaling $3.1 billion, that occurred from 2007 through 2010. In these transactions we 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 Targa in 2010, we have grown substantially, with large increases in a number of metrics as of year-end 2013, including our total assets (95%), adjusted EBITDA (70%), distributable cash flow (69%) and distributions to our common unitholders (39%). The expansion of our business has been fueled by a combination of major organic growth investments in our businesses and acquisitions.

Organic Growth Projects

We continue to invest significant capital to expand through organic growth projects. We have invested approximately $1.9 billion in growth capital expenditures since 2007, including approximately $1 billion in 2013. These expansion investments were distributed across our businesses, with 54% related to Logistics and Marketing and 46% to Gathering and Processing. We will continue to invest in both large and small organic growth projects in 2014, with $650 million of estimated growth capital expenditures for announced projects.

Major organic growth projects completed or underway include:

- *International Exports.* In September 2013, we commissioned Phase I of our international export expansion project, which includes facilities at both Mont Belvieu facility and at our Galena Park Marine Terminal near Houston, Texas. Phase I of this project expanded our export capability to approximately 3.5 to 4 MMBbl per month of propane and/or butane. Included in our Phase I expansion is the capability to export international grade low ethane propane. With the completion of Phase I, our capabilities expanded to include loading very large gas carrier ("VLGC") vessels in addition to the small and medium-sized vessels that we loaded for export. Construction is underway to further expand our propane and butane international export capacity by approximately 2 MMBbl per month, with an expected completion of Phase II in the third quarter of 2014. We expect that the total cost of both phases of our international export project to be approximately $480 million.

- *Cedar Bayou Fractionator Train 4.* In August 2013, we commissioned an additional fractionator, Train 4, at our 88%-owned Cedar Bayou Fractionator (“CBF”) in Mont Belvieu, Texas. This expansion added 100 MBbl/d of fractionation capacity at CBF. The gross cost of Train 4 was approximately $385 million (our net cost was approximately $352 million).

- *Badlands expansion program.* During 2013, we invested approximately $250 million to expand our gathering and processing business in the Williston Basin, North Dakota assets. We increased our 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, we anticipate that we will invest approximately $180 million for further expansion of this business, including an additional cryogenic processing plant.

- *North Texas Longhorn plant.* We are constructing a new 200 MMcf/d cryogenic processing plant and related gathering and compression facilities for North Texas to meet increasing production and continued producer activity in the area, with an anticipated completion in the second quarter of 2014. We expect a total estimated cost of approximately $150 million for the plant and associated projects.

- *SAOU High Plains plant.* We are constructing a new 200 MMcf/d cryogenic processing plant and related gathering and compression facilities for SAOU to meet increasing production and continued producer activity on the eastern side of the Permian Basin, with an anticipated completion date in mid-2014. We expect a total estimated cost of approximately $225 million for the plant and associated projects.

Additionally, we expect to have other growth capital expenditures in 2014 related to the continued build out of our gathering and processing systems and logistics capabilities.

Acquisitions of Businesses and Assets

In addition to our organic growth projects, we have made several business and asset acquisitions, including:

Badlands

On December 31, 2012, we acquired Saddle Butte Pipeline LLC’s crude oil gathering pipeline and terminal system and natural gas gathering and processing operations, collectively referred to as “Badlands” for cash consideration of approximately $976 million. The business is located in the Bakken and Three Forks Shale plays of the Williston Basin in North Dakota.

Petroleum Logistics

During 2011 and 2012, we acquired refined petroleum products and crude oil storage facilities, including potential export capabilities in a series of transactions. Facilities acquired were located on the Houston Ship Channel, the Hylebos Waterway in the Port of Tacoma, Washington (the “Sound Terminal”) and on the Patapsco River in Baltimore, Maryland (the “Baltimore Terminal”).

Growth Drivers

We believe our near-term growth will be driven by significant organic growth investments to meet strong supply and demand fundamentals for our existing businesses. We believe our assets are not easily duplicated and are located in active producing areas and near key markets and logistics centers. Over the longer term, we expect our 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. We expect that third-party acquisitions will also continue to be a focus of our growth strategy.

Strong supply and demand fundamentals for our existing businesses

We believe that the current levels of oil, condensate and NGL prices and the forecasted prices for these energy commodities have caused producers in and around our crude oil gathering and natural gas gathering and gas processing areas of operation to focus their drilling programs on regions rich in these forms of hydrocarbons. 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 our Badlands business in North Dakota.

The impact of high producer activity and resulting NGL supplies from areas rich in oil, condensate and NGLs continue to generate demand for our fractionation services at the Mont Belvieu market hub. As a result of the increasing demand, since 2010 we have added 178 MBbl/d in fractionation capacity with the additions of CBF Trains 3 and 4. We also funded our 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. We believe that the higher volumes of fractionated NGLs will also result in increased demand for other related fee-based services provided by our Downstream Business. Continued demand for fractionation capacity will lead to other growth opportunities, such as the potential to provide fractionation services of Mont Belvieu for producers in the Utica and Marcellus Shale plays in Ohio, West Virginia and Pennsylvania.

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, our integrated Mont Belvieu and Galena Park Terminal assets allow us to provide the raw product, fractionation, storage, interconnected terminaling, refrigeration and ship loading capabilities to support exports by third party customers.

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

We are actively pursuing natural gas gathering and processing and NGL fractionation opportunities associated with liquids-rich natural gas from shale and other resource plays, such as portions of the Barnett, Eagle Ford, Utica and Marcellus Shales and with even richer casinghead gas opportunities from active crude oil resource plays, such as the Wolfberry (and other named variants of Wolfcamp, Spraberry, Dean and other geologic cross-section combinations) and the Bone Springs, Avalon and Bakken Shale plays. We believe that our leadership position in the Downstream Business, which includes our fractionation services, provides us 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 is expected to make 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. We believe that competition with trucking and incentives to reduce flaring provide opportunities to grow volumes and expand our crude gathering and natural gas gathering and processing infrastructure; and that our position in the Williston Basin should allow us to compete for expansion opportunities. In addition, the significant amount of uncommitted acreage in proximity to our system should provide further opportunities for system expansions.

Third party acquisitions

While our growth through 2010 was primarily driven by the implementation of a focused drop down strategy, we and Targa also have a record of completing third party acquisitions. Since our formation, our strategy has included approximately $5.3 billion in acquisitions and growth capital expenditures of which approximately $1.2 billion was for acquisitions from third-parties. We expect that third-party acquisitions will continue to be a focus of our growth strategy.

Competitive Strengths and Strategies

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

Strategically located gathering and processing asset base

Our gathering and processing businesses are predominantly located in active and growth-oriented oil and gas producing basins. Activity in the shale resource plays underlying our gathering assets is driven by oil, condensate and NGL production and currently favorable prices for those energy commodities. Increased drilling and production activities in these areas would likely increase the volumes of natural gas and crude oil available to our gathering and processing systems.

Leading fractionation and NGL infrastructure position

We are one of the largest fractionators of NGLs in the Gulf Coast. Our primary fractionation assets are located in Mont Belvieu, Texas and Lake Charles, Louisiana, which are key market centers for NGLs, and most 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. Our Logistics assets, including fractionation facilities, storage wells, our marine export/import terminal and related pipeline systems and interconnects, are also located near and connected to key consumers of NGL products including the petrochemical and industrial markets. The location and interconnectivity of these assets are not easily replicated, and we have sufficient additional capability to expand their capacity. We have extensive experience in operating these assets and developing, permitting and constructing new midstream assets.

Comprehensive package of midstream services

We provide a comprehensive package of services to natural gas and crude oil producers. These services are essential to gather crude and to process and treat wellhead gas to meet pipeline standards and to extract NGLs for sale into petrochemical, industrial, commercial and export markets. We believe our ability to provide these integrated services provides an advantage in competing for new supplies because we can provide substantially all of the services producers, marketers and others require for moving natural gas and NGLs from wellhead to market on a cost-effective basis. Additionally, we believe that the barriers to enter the midstream sector on a scale similar to ours are reasonably high due to the high cost of replicating assets in key strategic positions, the difficulty of permitting and constructing new midstream assets and the difficulty of developing the expertise necessary to operate them.

High quality and efficient assets

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

In addition to routine annual maintenance expenses, our maintenance capital expenditures have averaged approximately $80 million per year over the last three years. We believe that our assets are well-maintained and anticipate that a similar level of maintenance capital expenditures will be sufficient for us to continue to operate these assets in a prudent and cost-effective manner.

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

We maintain gas gathering and processing positions in strategic oil and gas producing areas across multiple basins and provide services under attractive contract terms to a diverse mix of customers across our areas of operation. Consequently, we are not dependent on any one oil and gas basin or customer. Our Logistics and Marketing assets are typically located near key market hubs and near 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.

Our contract portfolio has attractive rate and term characteristics, with a heavy fee-based component, especially in our Downstream Business and our Badlands operations. We expect an increasing percentage of our net operating cash flows to be fee-based given the higher rates for logistics assets contracts that are being newly executed or renewed under long-term contracts, the new projects underway, and continuing strong supply and demand fundamentals for this business. Our expected continued growth of the fee-based Badlands business in North Dakota will also contribute to increasing fee-based cash flow.

Financial flexibility

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

Experienced and long-term focused management team

The executive management team that formed Targa in 2004 continues to manage Targa today. 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 our assets and businesses.

Attractive cash flow characteristics

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

We have hedged the commodity price risk associated with a portion of our expected natural gas equity volumes through 2016 and NGL and condensate equity volumes through 2014 by entering into financially settled derivative transactions. Historically, these transactions have included both swaps and purchased puts (or floors). The primary purpose of our commodity risk management activities is to hedge our exposure to price risk and to mitigate the impact of fluctuations in commodity prices on cash flow. We have intentionally tailored our hedges to approximate specific NGL products and to approximate our actual NGL and residue natural gas delivery points. Although the degree of hedging will vary, we intend to continue to manage some of our exposure to commodity prices by entering into similar hedge transactions as market conditions permit. We also monitor and manage our inventory levels with a view to mitigate losses related to downward price exposure.

Asset base well-positioned for organic growth

We believe our asset platform and strategic locations allow us to maintain and potentially grow our volumes and related cash flows as our supply areas continue to benefit from exploration and development. At current and recent historical prices, technology advances have resulted in increased domestic oil and liquids-rich gas drilling and production activity. The location of our assets provides us with access to stable natural gas and crude oil supplies and proximity to end-use markets and liquid market hubs while positioning us to capitalize on drilling and production activity in those areas. Our existing infrastructure has the capacity to handle some incremental increases in volumes without significant investments as well as opportunities to leverage existing assets with meaningful expansions. We believe that as domestic supply and demand for natural gas, crude oil and NGLs, and services for each, grows over the long term, our infrastructure will increase in value as such infrastructure takes on increasing importance in meeting that growing supply and demand.

While we have set forth our strategies and competitive strengths above, our business involves numerous risks and uncertainties which may prevent us from executing our strategies or impact the amount of distributions to 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 our inability to access sufficient additional production to replace natural declines in production. For a more complete description of the risks associated with an investment in us, see "Item 1A. Risk Factors."

Relationship with Targa

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

As of December 31, 2013, Targa and its named executive officers and directors have a significant ownership interest in us through their ownership of a 12.0% limited partner interest and Targa's 2% general partner interest. In addition, Targa owns incentive distribution rights that entitle Targa to receive an increasing percentage of quarterly distributions of available cash from our operating surplus after the minimum quarterly distribution and the target distribution levels have been achieved. The Partnership agreement governs our relationship regarding certain reimbursement and indemnification matters. See "Item 13. Certain Relationships and Related Transactions and Director Independence."

We do not have any employees to carry out our operations. Targa employs 1,277 people. See "—Employees." Following the conveyance of assets to us in September 2010, Targa charges us for all the direct costs of the employees assigned to our operations, as well as all general and administrative support costs other than its direct support costs of being a separate reporting company and its cost of providing management and support services to certain unaffiliated spun-off entities. We generally reimburse Targa for cost allocations to the extent that they have required a current cash outlay by Targa.

Our Challenges

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

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

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

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

- If we do not successfully integrate assets from acquisitions, our results of operations and financial condition could be adversely affected.

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

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

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

- Our hedging activities may not be effective in reducing the variability of our cash flows and may, in certain circumstances, increase the variability of our cash flows.

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

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

Our Business Operations

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

Gathering and Processing Division

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

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

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

Field Gathering and Processing Segment

In 2013, 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 our gathering systems which, in aggregate, consist of approximately 11,300 miles of natural gas pipelines and include ten owned and operated processing plants. During 2013, we processed an average of 780.1 MMcf/d of natural gas and produced an average of 91.9 MBbl/d of NGLs.

In addition to our natural gas gathering and processing, our Badlands operations include a crude oil gathering system and two terminals with crude oil operational storage capacity of 70 MBbl.

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

The Field Gathering and Processing segment's operations consist of 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 1,500 miles of natural gas gathering pipelines. These gathering systems are 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 our ownership interest). These plants have residue gas connections to pipelines owned by affiliates of Kinder Morgan and MidAmerican Energy Company. Our ownership in Versado is held through Versado Gas Processors, L.L.C., a consolidated joint venture that is 63% owned by us and 37% owned by Chevron U.S.A. Inc.

SAOU

SAOU includes approximately 1,800 miles of pipelines in the Permian Basin that gathers natural gas for delivery to the Mertzon, Sterling and Conger 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 169 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,

We are currently constructing the High Plains plant, a new 200 MMcf/d cryogenic processing plant and related gathering and compression facilities with an anticipated completion date in mid-2014. The new plant will enable SAOU to meet increasing production and continued producer activity on the eastern side of the Permian Basin.

North Texas

North Texas includes two interconnected gathering systems with approximately 4,500 miles of pipelines gathering wellhead natural gas for the Chico and Shackelford 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 2,400 miles of gathering pipelines. Wellhead natural gas is either gathered for the Chico plant 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 plant. The plant has an aggregated processing capacity of 265 MMcf/d and an integrated fractionation capacity of 15 MBbl/d. The Shackelford gathering system includes approximately 2,100 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.

To meet increasing production and producer activity in North Texas, we are currently constructing the Longhorn plant, a new 200 MMcf/d cryogenic processing plant, with expected completion in the second quarter of 2014.

Badlands

The Badlands operations are located in the Bakken and Three Forks Shale plays of the Williston Basin in North Dakota and include 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. We have an additional 30 MBbl of operational crude oil storage under construction at New Town and 25 MBbl of operational crude oil storage under construction at Stanley. Badlands also includes natural gas gathering pipelines and a natural gas processing plant that was expanded in the third quarter of 2013 by 20 MMcf/d to a gross processing capacity of about 38 MMcf/d.

During 2013, we invested approximately $250 million to expand our 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, 2013:

Facility	% Owned	Location	Estimated Gross Processing Capacity (MMcf/d)(1)	Gross Plant Natural Gas Inlet Throughput Volume (MMcf/d) (9)	Gross NGL Production (MBbl/d) (9)	Process Type (8)	Operated or Non-Operated
Sand Hills							
Sand Hills	100	Crane, TX	175.0	148.8	17.4	Cryo	Operated
Puckett (2)				7.0	0.1		
		Area Total	175.0	155.8	17.5		
Versado							
Saunders (3), (4)	63	Lea, NM	60.0	29.4	3.1	Cryo	Operated
Eunice (3), (4)	63	Lea, NM	95.0	75.4	9.7	Cryo	Operated
Monument (3), (4)	63	Lea, NM	85.0	51.5	6.0	Cryo	Operated
		Area Total	240.0	156.3	18.8		
SAOU							
Mertzon	100	Irion, TX	52.0	52.8	8.3	Cryo	Operated
Sterling	100	Sterling, TX	92.0	77.2	11.1	Cryo	Operated
Conger	100	Sterling, TX	25.0	23.3	3.0	Cryo	Operated
		Area Total (7)	169.0	153.3	22.4		
North Texas							
Chico (5)	100	Wise, TX	265.0	284.4	30.0	Cryo	Operated
Shackelford	100	Shackelford, TX	13.0	9.2	1.1	Cryo	Operated
		Area Total (7)	278.0	293.6	31.1		
Badlands							
Little Missouri (6)	100	McKenzie, ND	38.0	21.4	1.9	RA	Operated
	Segment System Total		900.0	780.4	91.7		

(1) Gross processing capacity 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) Puckett volumes are gathered in our pipelines and processed at third-party plants.
(3) Includes throughput other than plant inlet, primarily from compressor stations.
(4) These plants are part of our Versado joint venture. Capacity and volumes represent 100% of ownership interest.
(5) The Chico plant has fractionation capacity of approximately 15 MBbl/d.
(6) Additional refrigerated compression will be installed in March 2014, bringing the gas plant throughput capacity to 44 MMcf/d.
(7) Includes volumes gathered in our pipelines that are beyond our current plant capacity and are processed at other third-party plants.
(8) Cryo – Cryogenic; RA – Refrigerated Absorption Processing.
(9) Operational reports are used as the source of the Gross Inlet Throughput and NGL Production for certain plant statistics listed above, which may vary from financial statistics by insignificant amounts.

Coastal Gathering and Processing Segment

Coastal Gathering and Processing segment assets are located in the onshore region of the Louisiana Gulf Coast, accessing natural gas from the Gulf Coast and the Gulf of Mexico. With the strategic location of our assets in Louisiana, we have access to the Henry Hub, the largest natural gas hub in the U.S., and to a substantial NGL distribution system with access to markets throughout Louisiana and the southeast U.S. The Coastal Gathering and Processing segment's assets consist of LOU and the Coastal Straddles, each as described below. For the year ended 2013, we processed an average of 1,330.1 MMcf/d of plant natural gas inlet and produced an average of 44.9 MBbl/d of NGLs.

LOU

LOU consists of approximately 1,000 miles of 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.

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 deepwater Gulf of Mexico production via connections to third-party pipelines or through pipelines owned by us. Coastal Straddles has access to markets across the U.S. through the interstate natural gas pipelines to which they are interconnected. The industry continues to rationalize gas processing capacity along the Gulf Coast by moving gas from older, less efficient plants to higher efficiency cryogenic plants. In the last two years, the Yscloskey, Calumet and other third-party plants have been shut-down, with most of the producer volumes going to more efficient plants such as our Venice, Lowry and Barracuda plants.

VESCO

Through our 76.8% ownership interest in Venice Energy Services Company, L.L.C, we operate the Venice gas plant, which has a 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 us. The plants, having an aggregate processing capacity of approximately 3,555 MMcf/d, are generally situated on mainline natural gas pipelines near the coastline and process volumes of natural gas collected from multiple offshore gathering systems and pipelines throughout the Gulf of Mexico. Coastal Straddles also has ownership in two offshore gathering systems that are operated by us. The Pelican and Seahawk gathering systems have a combined length of approximately 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.

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The following table lists the Coastal Gathering and Processing segment's natural gas processing plants and related volumes for the year ended December 31, 2013:

Facility	% Owned	Location Parish, State	Estimated Gross Processing Capacity (MMcf/d) (1)	Plant Natural Gas Inlet Throughput Volume (MMcf/d)	NGL Production (MBbl/d)	Process Type (2)	Operated or Non-operated
LOU							
Gillis (3)	100	Calcasieu, LA	180	171.0	6.8	Cryo	Operated
Acadia	100	Acadia, LA	80	21.8	0.9	Cryo	Operated
Big Lake	100	Calcasieu, LA	180	158.1	2.6	Cryo	Operated
		Area Total	440	350.9	10.3		
VESCO (4), (5)	76.8	Plaquemines, LA	750	515.5	21.5	Cryo	Operated
Other Coastal Straddles (6)							
Barracuda	100	Cameron, LA	190	58.9	1.7	Cryo	Operated
Stingray (7)	100	Cameron, LA	300	96.6	2.5	RA	Operated
Lowry	100	Cameron, LA	265	176.8	4.3	Cryo	Operated
Terrebonne (8), (9)	4.6	Terrebonne, LA	950	19.6	0.6	RA	Non-operated
Toca (8), (9)	9.2	St. Bernard, LA	1,150	38.3	1.2	Cryo/RA	Non-operated
Sea Robin (8)	0.8	Vermillion, LA	700	15.9	0.5	Cryo	Non-operated
Other (10)				57.6	2.3		
		Area Total	3,555	463.7	13.1		
	Consolidated System Total		4,745	1,330.1	44.9		

(1) Gross processing capacity may differ from nameplate processing capacity due to multiple factors including items such as compression limitations, and the quality and composition of the gas being processed
(2) Cryo – Cryogenic Processing; RA – Refrigerated Absorption Processing.
(3) The Gillis plant has fractionation capacity of approximately 11 MBbl/d.
(4) Plant natural gas inlet throughput volumes for VESCO represent 100% of the volumes associated with the plant as we consolidate VESCO's results due to our 76.8% ownership interest.
(5) VESCO also includes an offshore gathering system with a combined length of approximately 150 miles.
(6) Other Coastal Straddles also includes two offshore gathering systems which have a combined length of approximately 175 miles.
(7) The Stingray Plant was idled on December 8, 2013. Most of the producer volumes from this plant were moved to either the Barracuda or Lowry Plants.
(8) Plant natural gas inlet throughput volumes for non-operated plants represent volumes associated with our ownership percentages.
(9) Our ownership is adjustable and subject to annual redetermination based on our proportionate share of owners production.
(10) Other includes Sabine Pass and Neptune volumes processed at plants not owned by us. The Sabine Pass Plant was shut down on January 3, 2013 with most of the producer volumes going to our Barracuda Plant.

Logistics and Marketing Division

Our Logistics and Marketing Division is also referred to as the Downstream Business. It includes the activities necessary to convert mixed NGLs into NGL products and provide certain value-added services such as the fractionation, storage, terminaling, transportation, distribution and marketing of NGLs and NGL products; the storing and terminaling of refined petroleum products and crude oil; and certain natural gas supply and marketing activities in support of our other businesses. These products are delivered to end-users through pipelines, barges, trucks and rail cars. End-users of NGL products include petrochemical and refining companies 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 and other industrial end-users, they must be fractionated into their component products and delivered to various points throughout the U.S. Our logistics assets are generally connected to, and supplied in part by, our gathering and processing assets and are primarily located at Mont Belvieu and Galena Park near Houston, Texas and in Lake Charles, Louisiana. This segment also contains refined petroleum product and crude oil storage and terminaling.

Fractionation

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

Our fractionation assets include ownership interests in three stand-alone fractionation facilities that are located on the Gulf Coast, two of which we operate, one at Mont Belvieu, Texas and the other at Lake Charles, Louisiana. We have an equity investment in the third fractionator, GCF, also located at Mont Belvieu. We are subject to a consent decree with the Federal Trade Commission, issued December 12, 1996, that, among other things, prevents us from participating in commercial decisions regarding rates paid by third parties for fractionation services at GCF. This restriction on our activity at GCF will terminate on December 12, 2016, twenty years after the date the consent order was issued. In addition to the three stand-alone facilities in the Logistics Assets segment, see the description of fractionation assets in the North Texas System and LOU in our Gathering and Processing division.

We expanded the fractionation capacity of our assets during 2011 through 2013 with the following projects:

- *CBF Train 3 and 4.* In the second quarter of 2011, we commissioned 78 MBbl/d of additional fractionation capacity, Train 3, at CBF, in Mont Belvieu, Texas, at a gross cost of approximately $64 million. Train 3 is supported by long-term fee-based contracts that have certain guaranteed volume commitments or provisions for deficiency payments. In August 2013, we commissioned an additional fractionator, Train 4. This expansion added 100 MBbl/d of fractionation capacity. The gross cost of Train 4 was approximately $385 million (our net cost was approximately $345 million) and is also 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 we own 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 (our net cost was approximately $35 million) for an estimated ultimate capacity of approximately 125 MBbl/d.

The majority of our NGL fractionation business is under fee-based arrangements. These fees are subject to adjustment for changes in certain fractionation expenses, including energy costs. The operating results of our NGL fractionation business are dependent upon the volume of mixed NGLs fractionated and the level of fractionation fees charged.

We believe 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 deepwater Gulf of Mexico. Hydrocarbon dew point specifications implemented by individual natural gas pipelines and the Policy Statement on *Provisions Governing Natural Gas Quality and Interchangeability in Interstate Natural Gas Pipeline Company Tariffs* enacted in 2006 by the Federal Energy Regulatory Commission (“FERC”) should result in volumes of mixed NGLs being available for fractionation because natural gas requires processing or conditioning to meet pipeline quality specifications. These requirements establish a base volume of mixed NGLs during periods when it might be otherwise uneconomical to process certain sources of natural gas. Furthermore, significant volumes of mixed NGLs are contractually committed to our NGL fractionation facilities.

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

We also have a natural gasoline hydrotreater at Mont Belvieu, Texas that removes sulfur from natural gasoline, allowing customers to meet new, more stringent environmental standards. The facility has a capacity of 30 MBbl/d and is supported by long-term fee-based contracts that have certain guaranteed volume commitments or provisions for deficiency payments. In 2012, we 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 our long-term customer accounts. Similar to the hydrotreater, the benzene saturation process is supported by 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 2013 (MBbl/d)(2)**
Operated Facilities:			
Lake Charles Fractionator (Lake Charles, LA)	100.0	55.0	24.0
Cedar Bayou Fractionator (Mont Belvieu, TX) (3)	88.0	393.0	278.1
Targa LSNG Hydrotreater (Mont Belvieu, TX)	100.0	30.0	20.2
Non-operated Facilities:			
Gulf Coast Fractionator (Mont Belvieu, TX)	38.8	125.0	115.8

(1) Actual fractionation capacities may also vary due to the Y-grade composition of the gas being processed and does not assume ethane rejection.
(2) Gross throughput for 2013 only includes a partial year for Train 4, which was placed in service in August 2013.
(3) Gross capacity represents 100% of the volume associated with the plant following the completion of Train 4. Capacity includes 40 MBbl/d of additional butane/gasoline fractionation capacity.

Storage, Terminaling and Petroleum Logistics

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

Our Petroleum Logistics business consists of storage and terminaling facilities in Texas (the Channelview Terminal and the Patriot facility), Maryland (the Baltimore Terminal) and Washington (the Sound Terminal). These facilities primarily serve the refined petroleum products and crude oil markets, but potentially may also include LPG and biofuels.

Across the Logistics Assets segment, we own or operate a total of 39 storage wells at our facilities with a net storage capacity of approximately 64 MMBbl, the usage of which may be limited by brine handling capacity, which is utilized to displace NGLs from storage.

We operate our storage and terminaling facilities based on the needs and requirements of our customers. We usually experience an increase in demand for storage and terminaling of mixed NGLs during the summer months when gas plants typically reach peak NGL production, and refineries have excess NGL products. Demand for storage and terminaling at our propane facilities typically peaks during fall, winter and early spring. In September 2013, we commissioned Phase I of our international export expansion project that includes facilities at both our Mont Belvieu facility and our Galena Park Marine Terminal near Houston, Texas. Phase I of this project expanded our export capability to approximately 3.5 to 4 MMBbl per month of propane and/or butane. Included in the Phase I expansion was the capability to export international grade low ethane propane. With the completion of Phase I, we also added capabilities to load VLGC vessels alongside the small and medium sized export vessels that we load for export. We expect completion of Phase II of our International Exports project by the third quarter of 2014, which will add another estimated 2 MMBbl per month of export capacity. We continue to experience significant demand growth for NGL (primarily propane) exports.

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

The following table details the Logistics Assets NGL storage facilities at December 31, 2013:

Facility	% Owned	County/Parish, State	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)	43.0
Easton Storage	100	Evangeline, LA	1	0.8

(1) Five of twelve owned wells leased to CITGO under long-term leases.
(2) We own 20 wells and operate 6 wells owned by Chevron Phillips Chemical Company LLC ("CPC").

The following table details the Logistics Assets NGL and Petroleum Terminal Facilities for the year ended December 31, 2013:

Facility	% Owned	County/Parish, State	Description	Throughput for 2013 (Million gallons)	Usable Storage Capacity (MMBbl)
Galena Park Terminal (1)	100	Harris, TX	NGL import/export terminal, chemicals	1,900.0	0.7
Mont Belvieu Terminal	100	Chambers, TX	Transport and storage terminal	4,965.0	39.0
Hackberry Terminal	100	Cameron, LA	Storage terminal	889.3	17.8
Channelview Terminal	100	Harris, TX	Refined products, crude - transport and storage terminal	153.8	0.5
Baltimore Terminal	100	Baltimore, MD	Refined products - transport and storage terminal	8.0	0.5
Sound Terminal	100	Pierce, WA	Refined products, crude oil/propane - transport and storage terminal	422.4	0.9
Patriot	100	Harris, TX	Dock and land for expansion (Not in service)	N/A	N/A

(1) Volumes reflect total import and export across the dock/terminal and may also include volumes that have also been handled at the Mont Belvieu Terminal.

Marketing and Distribution Segment

The Marketing and Distribution segment transports, distributes and markets NGLs via terminals and transportation assets across the U.S. We own or commercially manage terminal facilities in a number of states, including Texas, Louisiana, Arizona, Nevada, California, Florida, Alabama, Mississippi, Tennessee, Kentucky, New Jersey and Washington. The geographic diversity of our assets provide direct access to many NGL customers as well as markets via trucks, barges, 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

We market our own NGL production and also purchase component NGL products from other NGL producers and marketers for resale. Additionally, we also purchase product for resale in our Logistics segment, including exports. During the year ended December 31, 2013, our distribution and marketing services business sold an average of approximately 318.4 MBbl/d of NGLs.

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

Wholesale Marketing

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

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

Refinery Services

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

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

Commercial Transportation

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

Our transportation assets, as of December 31, 2013, include:

- approximately 700 railcars that we lease and manage;
- approximately 80 owned and leased transport tractors; and
- 18 company-owned pressurized NGL barges.

Natural Gas Marketing

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

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

Facility	% Owned	County/Parish, State	Description	Throughput for 2013 (Million gallons) (1)	Usable Storage Capacity (Million gallons)
Calvert City Terminal	100	Marshall, KY	Propane terminal	12.2	0.1
Greenville Terminal	100	Washington, MS	Marine propane terminal	18.3	1.5
Port Everglades Terminal	100	Broward, FL	Marine propane terminal	8.8	1.6
Tyler Terminal	100	Smith, TX	Propane terminal	12.8	0.2
Abilene Transport (2)	100	Taylor, TX	Raw NGL transport terminal	0.8	Less than 0.1
Bridgeport Transport (2)	100	Jack, TX	Raw NGL transport terminal	0.3	0.1
Gladewater Transport (2)	100	Gregg, TX	Raw NGL transport terminal	3.9	0.3
Chattanooga Terminal	100	Hamilton, TN	Propane terminal	9.1	0.9
Sparta Terminal	100	Sparta, NJ	Propane terminal	16.0	0.2
Hattiesburg Terminal (3)	50	Forrest, MS	Propane terminal	259.6	269.6
Winona Terminal	100	Flagstaff, AZ	Propane terminal	14.6	0.3
Sound Terminal (4)	100	Pierce, WA	Propane terminal	3.3	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 volumes.
(4) Operated by Logistics Assets segment.

Operational Risks and Insurance

We are subject to all risks inherent in the midstream natural gas, crude oil and petroleum logistics businesses. These risks include, but are not limited to, explosions, fires, mechanical failure, terrorist attacks, product spillage, weather, nature and inadequate maintenance of rights-of-way and could result in damage to or destruction of operating assets and other property, or could result in personal injury, loss of life or environmental pollution, as well as curtailment or suspension of operations at the affected facility. Targa maintains, on behalf of us and our subsidiaries, general public liability, property, boiler and machinery and business interruption insurance in amounts that we consider to be appropriate for such risks. Such insurance is subject to deductibles that we consider reasonable and not excessive given the current insurance market environment. The costs associated with this insurance coverage increased significantly following Hurricanes Katrina and Rita in 2005 and then again following Hurricanes Gustav and Ike and as a result of volatile conditions in the financial markets in 2008. Insurance premiums, deductibles and co-insurance requirements increased substantially, and terms were generally less favorable than terms that were obtained prior to these events.

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

Significant Customer

The following table lists the percentage of our consolidated sales with our significant customer:

	2013	2012	2011
% of consolidated revenues			
Chevron Phillips Chemical Company LLC	8%	10%	12%

We have agreements with Chevron Phillips Chemical Company LLC ("CPC"), pursuant to which we supply a significant portion of CPC's NGL feedstock needs for petrochemical plants in the Texas Gulf Coast area and a related services agreement, pursuant to which we provide storage and logistical services to CPC for feedstocks and products produced from the petrochemical plants. The services contract was renegotiated in 2008 with key components having a ten year term. In September 2009, we executed a new feedstock and storage agreement with CPC for a term of five years, and amended these agreements in 2013, with a new term through August 2019. We believe that we are well positioned to retain CPC as a customer based on our long-standing history of customer service, the criticality of the service provided, the integrated nature of facilities and the difficulty and high cost associated with replicating our assets.

No customer accounted for more than 10% of our consolidated revenues during the year ended December 31, 2013.

Competition

We face strong competition in acquiring new natural gas supplies. Competition for natural gas and crude oil supplies is primarily based on the location of gathering and processing facilities, pricing arrangements, reputation, efficiency, flexibility, reliability and access to end-use markets or liquid marketing hubs. Competitors to our gathering and processing operations include other natural gas gatherers and processors, such as major interstate and intrastate pipeline companies, master limited partnerships and oil and gas producers. Our major competitors for natural gas supplies in our current operating regions include Atlas Gas Pipeline Company, Kinder Morgan Energy Partners, L.P., WTG Gas Processing, L.P. (“WTG”), DCP Midstream Partners LP (“DCP”), Devon Energy Corp (“Devon”), Enbridge Inc, ONEOK – Rockies Midstream, L.L.C., GulfSouth Pipeline Company, LP, Hanlon Gas Processing, Ltd., J W Operating Company, Louisiana Intrastate Gas and several other interstate pipeline companies. Our competitors for crude oil gathering services in North Dakota include Arrow Midstream Holdings, LLC, Hiland Partners, LP, Great Northern Midstream LLC, Caliber Midstream Partners, LP and Bridger Pipeline LLC. Our competitors may have greater financial resources than we possess.

We also compete for NGL products to market through our Logistics and Marketing division. Our competitors include major oil and gas producers who market NGL products for their own account and for others. Additionally, we compete with several other NGL marketing companies, including Enterprise Products Partners L.P. (“EPP”), DCP, ONEOK and BP p.l.c.

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

Regulation of Operations

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

Regulation of Interstate Natural Gas Pipelines

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

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

The maximum recourse rates that may be charged by VGS for its services are established through FERC's ratemaking process. Generally, the maximum filed recourse rates for interstate pipelines are based on the cost of service, including recovery of and a return on the pipeline's investment. Key determinants in the ratemaking process are costs of providing service, allowed rate of return and volume throughput and contractual capacity commitment assumptions. VGS is permitted to discount its firm and interruptible rates without further FERC authorization down to the variable cost of performing service, provided they do not "unduly discriminate." The applicable recourse rates and terms and conditions for service are set forth in each pipeline's FERC-approved tariff. Rate design and the allocation of costs also can impact a pipeline's profitability.

Gathering Pipeline Regulation

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

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

Intrastate Pipeline Regulation

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

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

Our Louisiana intrastate pipeline, Targa Louisiana Intrastate LLC ("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 we charge for intrastate transportation are deemed just and reasonable unless challenged in a complaint. We cannot predict whether such a complaint will be filed against us in the future. Failure to comply with state regulations can result in the imposition of administrative, civil and criminal penalties.

Our intrastate NGL pipelines in Louisiana gather mixed NGLs streams that we own from processing plants in Louisiana and deliver such streams to the Gillis fractionators in Lake Charles, Louisiana, where the mixed NGLs streams are fractionated into various products. We deliver such refined petroleum products (ethane, propane, butanes and natural gasoline) out of our fractionator to and from Targa-owned storage, to other third-party facilities and to various third-party pipelines in Louisiana. These pipelines are not subject to FERC regulation or rate regulation by the DNR, but are regulated by United States Department of Transportation ("DOT") safety regulations.

Our intrastate pipelines in North Dakota are subject to the various regulations of the State of North Dakota. In addition, various federal agencies within the U.S. Department of the Interior, particularly the Bureau of Land Management, Office of Natural Resources Revenue (formerly the Minerals Management Service) and the Bureau of Indian Affairs, as well as the Three Affiliated Tribes, promulgate and enforce regulations pertaining to operations on the Fort Berthold Indian Reservation, on which we operate a significant portion of our Badlands gathering and processing assets. The Three Affiliated Tribes is a sovereign nation having the right to enforce certain laws and regulations independent from federal, state and local statutes and regulations.

Natural Gas Processing

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

Sales of Natural Gas and NGLs

The price at which we buy and sell natural gas and NGLs is currently not subject to federal rate regulation and, for the most part, is not subject to state regulation. However, with regard to our physical purchases and sales of these energy commodities and any related hedging activities that we undertake, we are required to observe anti-market manipulation laws and related regulations enforced by FERC and/or the Commodities Futures Trading Commission ("CFTC"). See "—Other Federal Laws and Regulation Affecting Our Industry—Energy Policy Act of 2005." Since May 1, 2009, we were required to report to FERC information regarding natural gas sale and purchase transactions for some of our operations depending on the volume of natural gas transacted during the prior calendar year. See "—Other Federal Laws and Regulation Affecting Our Industry—FERC Market Transparency Rules." Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third-party damage claims by, among others, market participants, sellers, royalty owners and taxing authorities.

Other State and Local Regulation of Operations

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

Interstate Common Carrier Liquids Pipeline Regulation

Targa NGL Pipeline Company LLC ("Targa NGL") has interstate NGL pipelines that are considered common carrier pipelines subject to regulation by FERC under the Interstate Commerce Act (the "ICA"). More specifically, Targa NGL owns a regulated twelve-inch diameter pipeline that runs between Lake Charles, Louisiana and Mont Belvieu, Texas. This pipeline can move mixed NGLs and purity NGL products. Targa NGL also owns an eight-inch diameter pipeline and a twenty-inch diameter pipeline, each of which run between Mont Belvieu, Texas and Galena Park, Texas. The eight-inch and the twenty-inch pipelines are also regulated and are part of an extensive mixed NGL and purity NGL pipeline receipt and delivery system that provides services to domestic and foreign import and export customers. The ICA requires that we maintain tariffs on file with FERC for each of these pipelines. Those tariffs set forth the rates we charge for providing transportation services as well as the rules and regulations governing these services. The ICA requires, among other things, that rates on interstate common carrier pipelines be "just and reasonable" and non-discriminatory. All shippers on these pipelines are our subsidiaries.

The crude oil pipeline system that is part of the Badlands assets has qualified for a temporary waiver of applicable FERC regulatory requirements under the ICA based on current circumstances. Such waivers are subject to revocation, however, 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, we would likely be required to file a tariff with FERC, provide a cost justification for the transportation charge, and provide service to all potential shippers without undue discrimination. Such a change in the jurisdictional status of transportation on this pipeline could adversely affect our results of operations.

Other Federal Laws and Regulations Affecting Our Industry

Domenici-Barton Energy Policy Act of 2005 ("EP Act of 2005")

The EP Act of 2005 is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans, and significant changes to the statutory policy that affects all segments of the energy industry. Among other matters, the EP Act of 2005 amends the NGA to add an anti-market manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC, and furthermore provides FERC with additional civil penalty authority. The EP Act of 2005 provides FERC with the power to assess civil penalties of up to $1 million per day for violations of the NGA and $1 million per violation per day for violations of the NGPA. The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce, including VGS. In 2006, FERC issued Order No. 670 to implement the anti-market manipulation provision of the EP Act of 2005. Order No. 670 does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of gas pipelines and storage companies that provide interstate services, as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction, which includes the annual reporting requirements under a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing (Order No. 704), and the quarterly reporting requirement under Order No. 735. The anti-market manipulation rule and enhanced civil penalty authority reflect an expansion of FERC's NGA enforcement authority.

FERC Market Transparency Rules

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

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

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

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

Environmental and Operational Health and Safety Matters

General

Our operations are subject to stringent and complex federal, regional, state and local laws and regulations governing the discharge of materials into the environment, worker health and safety, or otherwise relating to environmental protection. As with the industry generally, compliance with current and anticipated environmental laws and regulations increases our overall cost of business, including our capital costs to construct, maintain and upgrade equipment and facilities. 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 we can handle or dispose of our 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 our 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 sanctions including penalties, the imposition of removal or remedial obligations and the issuance of injunctions limiting or prohibiting our activities.

We have implemented programs and policies designed to keep our 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 our operations and financial position. We may be unable to pass on such increased compliance costs to our customers. Moreover, accidental releases or spills may occur in the course of our operations and we cannot assure you that we 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 we are 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 us, there is no assurance that the current regulatory standards will not become more onerous in the future, resulting in more significant costs to maintain compliance or increased exposure to significant liabilities, which could diminish our ability to make distributions to our unitholders. For example, following the collapse of a cavern wall in a salt dome being developed by a third party and the resulting creation of a sinkhole near the community of Bayou Corne in Assumption Parish, Louisiana, the Louisiana Department of Natural Resources issued a proposed rulemaking in late 2013 that, if adopted, would impose more stringent requirements in the operation of Class III injection wells and hydrocarbon storage wells in salt dome caverns including, among other things, placing strict distance limitations on the location of solution-mined caverns in relation to the outer boundaries of a salt stock within a salt dome. As proposed, the rulemaking, if adopted, would require us to abandon the operation of at least one storage well. We are continuing to assess the effect that this proposed rulemaking might have on our operations in the state.

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

Hazardous Substances and Waste

The Comprehensive Environmental Response, Compensation, and Liability Act, 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. We generate materials in the course of our operations that are regulated as “hazardous substances” under CERCLA or similar state statutes and, as a result, may be jointly and severally liable under CERCLA or such statutes for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment.

We also generate 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 our operations, we generate petroleum product wastes and ordinary industrial wastes such as paint wastes, waste solvents and waste compressor oils that are regulated as hazardous wastes. 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 our operations, being designated as “hazardous wastes” and therefore subject to more rigorous and costly disposal requirements. Any such changes in the laws and regulations could have a material adverse effect on our capital expenditures and operating expenses as well as those of the oil and gas industry in general.

We currently own or lease and have in the past owned or leased properties that for many years have been used for midstream natural gas and NGL activities and refined petroleum product and crude oil storage and terminaling activities. Although we have 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 us or on or under the other locations where these hydrocarbons or other substances and wastes have been taken for treatment or disposal. In addition, certain of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other substances and wastes was not under our control. These properties and any hydrocarbons, substances and wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes 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 our 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 us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions. The need to obtain permits has the potential to delay the development of oil and natural gas related projects. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. For example, on August 16, 2012, the EPA published final rules under the Clean Air Act that subject oil and natural gas production, processing, transmission and storage operations to regulation under the New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants federal programs. These final rules, among other things, revise existing requirements for volatile organic compound emissions from equipment leaks at onshore natural gas processing plants by lowering the leak definition for valves from 10,000 parts per million to 500 parts per million and requires monitoring of connectors, pumps, pressure relief devices and open-ended lines. n addition, these rules establish requirements regarding emissions from: (i) wet seal and reciprocating compressors at gathering systems, boosting facilities, and onshore natural gas processing plants; (ii) specified pneumatic controllers at gathering systems, boosting facilities, and onshore natural gas processing plants; and (iii) specified storage vessels at gathering systems, boosting facilities, and onshore natural gas processing plants. Compliance with these requirements could increase our operational costs for upstream and midstream activities, which could be significant.

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, establish GHG emission limits from motor vehicles as well as establish Prevention of Significant Deterioration (“PSD”) construction and Title V operating permit reviews for certain large stationary sources that are potential major sources of GHG emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet “best available control technology” standards that will be established by the states or, in some cases, by the EPA on a case-by-case basis. In October 2013, the U.S. Supreme Court agreed to hear a lawsuit challenging whether the EPA permissibly determined that the regulation of GHG emissions from new motor vehicles triggered permitting requirements under the Clean Air Act for stationary sources that emit GHGs, with a decision expected in 2014. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified onshore and offshore production sources, specified onshore and offshore production facilities and onshore processing, transmission and storage facilities in the United States on an annual basis. We are monitoring GHG emissions from our operations in accordance with the GHG emissions reporting rule and believe that our monitoring and reporting activities are in substantial compliance with applicable reporting obligations.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce emissions of GHGs in recent years. 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 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 our equipment and operations could require us to incur significant added costs to reduce emissions of GHGs or could adversely affect demand for the natural gas and NGLs we gather and process or fractionate. Moreover, if Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on operations and reduce demand for refined products, which could adversely affect the services we provide. Finally, some scientists have concluded that increasing concentrations of GHGs in the Earth’s atmosphere may produce climate change that could have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events; if such effects were to occur, they could have an adverse effect on our 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. 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 administrative, 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 our plants, and our pipelines. Under the OPA, owners and operators of facilities that handle, store, or transport oil are required to develop and implement oil spill response plans, and establish and maintain evidence of financial responsibility sufficient to cover liabilities related to an oil spill for which such parties could be statutorily responsible. We believe that we are in substantial compliance with the CWA, the OPA and analogous state laws.

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 the EPA has asserted limited regulatory authority over hydraulic fracturing, and has indicated it may seek to further expand its regulation of hydraulic fracturing. Also, the Bureau of Land Management has proposed regulations applicable to hydraulic fracturing conducted on federal and Indian oil and gas leases. 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. 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, the EPA and the U.S. Department of Energy. These studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing. While we do not conduct hydraulic fracturing, if new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where our oil and natural gas exploration and production customers operate, those customers could incur potentially significant added costs to comply with such requirements and experience delays or curtailment in the pursuit of exploration, development or production activities, which could reduce demand for our gathering, processing and fractionation services.

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 our facilities may be located in areas that are designated as habitat for endangered or threatened species, we believe that we are in substantial compliance with the ESA. If endangered species are located in areas of the underlying properties where we wish to conduct development activities, such work could be prohibited or delayed or expensive mitigation may be required. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service is required to make a determination on the listing of numerous species as endangered or threatened under the ESA before the completion of the agency's 2017 fiscal year. The designation of previously unprotected species as threatened or endangered in areas where we or our oil and natural gas exploration and production customers operate could cause us or our customers to incur increased costs arising from species protection measures and could result in delays or limitations in our customers' performance of operations, which could reduce demand for our midstream services.

Employee Health and Safety

We are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act, 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 our operations and that this information be provided to employees, state and local government authorities and citizens. We and the entities in which we own an interest are also subject to OSHA Process Safety Management regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. The regulations apply to any process that (1) involves a listed chemical in a quantity at or above the threshold quantity specified in the regulation for that chemical, or (2) involves certain flammable gases or flammable liquids present on site in one location in a quantity of 10,000 pounds or more. Flammable liquids stored in atmospheric tanks below their normal boiling point without the benefit of chilling or refrigeration are exempt. We have an internal program of inspection designed to monitor and enforce compliance with worker safety requirements. We believe that we are in substantial compliance with all applicable laws and regulations relating to worker health and safety.

Pipeline Safety

Many of our natural gas, NGL and crude pipelines are subject to regulation by the Pipeline and Hazardous Materials Safety Administration ("PHMSA") of the DOT 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 as well as crude oil, NGL and condensate pipeline facilities. Pursuant to these acts, PHMSA has promulgated regulations governing pipeline wall thickness, 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 established a series of rules requiring pipeline operators to develop and implement integrity management programs for gas transmission and hazardous liquid 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 our 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.

Most recently, 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 act 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 rules or standards relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation, testing to confirm that the material strength of certain pipelines are above 30% of specified minimum yield strength, 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 rules 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 or all of which tasks could result in our incurring increased operating costs that could be significant and 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. We currently estimate an annual average cost of $2.3 million for years 2014 through 2016 to perform necessary integrity management program testing on our pipelines required by existing PHMSA and state regulations. This estimate does not include the costs, if any, of any repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program, which costs could be substantial. However, we do not expect that any such costs would be material to our financial condition or results of operations.

We, or the entities in which we own an interest, inspect our pipelines regularly in compliance with state and federal maintenance requirements. Nonetheless, the adoption of new or amended regulations by PHMSA or the states that result in more stringent or costly pipeline integrity management or safety standards could have a significant adverse effect on us and similarly situated midstream operators. For 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. PHMSA continues to evaluate the public comments received with respect to more stringent integrity management programs and recently, pursuant to one of the requirements in the 2011 Pipeline Safety Act, published a proposed rulemaking on August 1, 2013, seeking comments on whether an expansion of high consequence areas would mitigate the need for class location requirements that have been used in the past primarily to differentiate risk along a pipeline.

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 in the recent past, expanded the scope of their regulatory inspections to include certain in-plant equipment and pipelines found within NGL fractionation facilities and associated storage facilities, in order to assess compliance of such equipment and pipelines with hazardous liquid 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 legal challenges are unsuccessful, midstream operators of NGL fractionation facilities and associated storage facilities subject to such inspection 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

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

Employees

We do not have any employees. To carry out our operations, Targa employs 1,277 people who support primarily our operations. None of those employees are covered by collective bargaining agreements. Targa considers its employee relations to be good.

Financial Information by Reportable Segment

See "Segment Information" included under Note 21 of the "Consolidated Financial Statements" for a presentation of financial results by reportable segment and see "Management's Discussion and Analysis of Financial Condition and Results of Operations–Results of Operations–By Segment" for a discussion of our financial results by segment.

Available Information

We make certain filings with the Securities and Exchange Commission ("SEC"), including our Annual Report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments and exhibits to those reports. We make such filings available free of charge through our website, *http://www.targaresources.com*, as soon as reasonably practicable after they are filed with the SEC. The filings are also available through the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549 or by calling 1-800-SEC-0330. Also, these filings are available on the internet at *http://www.sec.gov*. Our press releases and recent analyst presentations are also available on our website.

Item 1A. Risk Factors.

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

Risks Related to Our Business

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

We have a substantial amount of indebtedness. As of December 31, 2013 we had $395.0 million of borrowings outstanding, $86.8 million of letters of credit outstanding and $718.2 million of additional borrowing capacity available under the "TRP Revolver". In addition, we had $2,258.6 million outstanding under our senior unsecured notes, excluding $28.0 million in unamortized discounts. We also had $279.7 million of outstanding under our accounts receivable securitization facility (the "Securitization Facility"). Our $1.2 billion TRP Revolver allows us to request increases in commitments up to an additional $300 million. For the years ended December 31, 2013, 2012 and 2011, our consolidated interest expense was $131.0 million, $116.8 million and $107.7 million, respectively.

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

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

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

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

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

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

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

Increases in interest rates could adversely affect our business.

We have significant exposure to increases in interest rates. As of December 31, 2013, our total indebtedness was $2,933.3 million, excluding $28.0 million in unamortized discounts, of which $2,258.6 million was at fixed interest rates and $674.7 million was at variable interest rates. A one percentage point increase in the interest rate on our variable interest rate debt would have increased our consolidated annual interest expense by approximately $6.7 million. As a result of this significant amount of variable interest rate debt, our financial condition could be adversely affected by increases in interest rates.

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

We may be able to incur substantial additional indebtedness in the future. As of December 31, 2013, we had $395.0 million of borrowings outstanding, $86.8 million of letters of credit outstanding and $718.2 million of additional borrowing capacity available under the TRP Revolver. In addition, we had $279.7 million of borrowings outstanding under our Securitization Facility. We may be able to incur an additional $300 million of debt under the TRP Revolver if we request and are able to obtain commitments from lenders for such additional amount. Although the TRP Revolver contains restrictions on the incurrence of additional indebtedness, these restrictions are subject to a number of significant qualifications and exceptions, and any indebtedness incurred in compliance with these restrictions could be substantial. If we incur additional debt, the risks associated with our substantial leverage would increase.

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

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

- incur or guarantee additional indebtedness or issue preferred stock;
- pay distributions on our equity securities or redeem, repurchase or retire our equity securities or subordinated indebtedness;
- make investments and certain acquisitions;
- create restrictions on the payment of distributions to our equity holders;
- sell or transfer assets, including equity securities of our subsidiaries;
- engage in affiliate transactions,
- consolidate or merge;
- incur liens;
- prepay, redeem and repurchase certain debt, other than loans under the TRP Revolver;
- enter into sale and lease-back transactions or take-or-pay contracts; and
- change business activities conducted by us.

In addition, the TRP Revolver requires us to satisfy and maintain specified financial ratios and other financial condition tests. Our ability to meet those financial ratios and tests can be affected by events beyond our control, and we cannot assure you that we will meet those ratios and tests.

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

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

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

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

Our primary natural gas gathering and processing arrangements that expose us to commodity price risk are our percent-of-proceeds arrangements. For the years ended December 31, 2013 and 2012, our percent-of-proceeds arrangements accounted for approximately 48% and 43%, respectively, of our gathered natural gas volume. Under these arrangements, we generally process natural gas from producers and remit to the producers an agreed percentage of the proceeds from the sale of residue gas and NGL products at market prices or a percentage of residue gas and NGL products at the tailgate of our processing facilities. In some percent-of-proceeds arrangements, we remit to the producer a percentage of an index-based price for residue gas and NGL products, less agreed adjustments, rather than remitting a portion of the actual sales proceeds. Under these types of arrangements, our revenues and cash flows increase or decrease, whichever is applicable, as the prices of natural gas, NGLs and crude oil fluctuate. Please see “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Quantitative and Qualitative Disclosures about Market Risk.”

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

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

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

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

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

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

- operating a significantly larger combined organization and adding new or expanded operations;
- difficulties in the assimilation of the assets and operations of the acquired businesses or growth projects, especially if the assets acquired are in a new business segment and/or geographic area;
- the risk that crude oil and natural gas reserves expected to support the acquired assets may not be of the anticipated magnitude or may not be developed as anticipated;
- the failure to realize expected volumes, revenues, profitability or growth;
- the failure to realize any expected synergies and cost savings;
- coordinating geographically disparate organizations, systems and facilities;
- the assumption of environmental and other unknown liabilities;

- limitations on rights to indemnity from the seller in an acquisition or the contractors and suppliers in growth projects;
- failure to attain or maintain compliance with environmental and other governmental regulations;
- inaccurate assumptions about the overall costs of equity or debt;
- the diversion of management's and employees' attention from other business concerns; and
- customer or key employee losses at the acquired businesses or to a competitor.

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

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

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

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

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

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

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

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

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

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

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

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

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

We have entered into derivative transactions related to only a portion of our equity volumes. As a result, we will continue to have direct commodity price risk to the unhedged portion. Our actual future volumes may be significantly higher or lower than we estimated at the time we entered into the derivative transactions for that period. If the actual amount is higher than we estimated, we will have greater commodity price risk than we intended. If the actual amount is lower than the amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale of the underlying physical commodity. The percentages of our expected equity volumes that are covered by our hedges decrease over time. To the extent we hedge our commodity price risk; we may forego the benefits we would otherwise experience if commodity prices were to change in our favor. The derivative instruments we utilize for these hedges are based on posted market prices, which may be higher or lower than the actual natural gas, NGL and condensate prices that we realize in our operations. These pricing differentials may be substantial and could materially impact the prices we ultimately realize. In addition, market and economic conditions may adversely affect our hedge counterparties' ability to meet their obligations. Given volatility in the financial and commodity markets, we may experience defaults by our hedge counterparties in the future. As a result of these and other factors, our hedging activities may not be as effective as we intend in reducing the variability of our cash flows, and in certain circumstances may actually increase the variability of our cash flows. Please see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Quantitative and Qualitative Disclosures about Market Risk."

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

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

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

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

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

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

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

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

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

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

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

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

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

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

We have significant relationships with CPC as a customer for our marketing and refinery services. In some cases, these agreements are subject to renegotiation and termination rights.

For the years ended December 31, 2013 and 2012, approximately 8% and 10%, respectively, of our consolidated revenues were derived from transactions with CPC. Under many of our CPC contracts where we purchase or market NGLs on CPC's behalf, CPC may elect to terminate the contracts or renegotiate the price terms. To the extent CPC reduces the volumes of NGLs that it purchases from us or reduces the volumes of NGLs that we market on its behalf, or to the extent the economic terms of such contracts are changed, our revenues and our cash flow from operating activities could decline.

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

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

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

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

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

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

The weather in the areas in which we operate can cause disruptions and in some cases suspension of our operations. For example, unseasonably wet weather, extended periods of below freezing weather, or hurricanes may cause disruptions or suspensions of our operations, which could adversely affect our operating results. Potential climate changes may have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events and could have an adverse effect on our operations.

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

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

- damage to pipelines and plants, related equipment and surrounding properties caused by hurricanes, tornadoes, floods, fires and other natural disasters, explosions and acts of terrorism;

- inadvertent damage from third parties, including from motor vehicles and construction, farm or utility equipment;

- damage that is the result of our negligence or any of our employees' negligence;

- leaks of natural gas, NGLs, crude oil and other hydrocarbons or losses of natural gas or NGLs as a result of the malfunction of equipment or facilities;

- spills or other unauthorized releases of natural gas, NGLs, crude oil, other hydrocarbons or waste materials that contaminate the environment, including soils, surface water and groundwater, and otherwise adversely impact natural resources; and

- other hazards that could also result in personal injury, loss of life, pollution and/or suspension of operations.

These risks could result in substantial losses due to personal injury, loss of life, severe damage to and destruction of property and equipment, and pollution or other environmental damage, and may result in curtailment or suspension of our related operations. A natural disaster or other hazard affecting the areas in which we operate could have a material adverse effect on our operations. For example, in 2005 Hurricanes Katrina and Rita damaged gathering systems, processing facilities, NGL fractionators and pipelines along the Gulf Coast, including certain of our facilities, and curtailed or suspended the operations of various energy companies with assets in the region. The Louisiana and Texas Gulf Coast was similarly impacted in September 2008 as a result of Hurricanes Gustav and Ike. We are not fully insured against all risks inherent to our business. Additionally, while we are insured for pollution resulting from environmental accidents that occur on a sudden and accidental basis, we may not be insured against all environmental accidents that might occur, some of which may result in toxic tort claims. If a significant accident or event occurs that is not fully insured, if we fail to recover all anticipated insurance proceeds for significant accidents or events for which we are insured, or if we fail to rebuild facilities damaged by such accidents or events, our operations and financial condition could be adversely affected. In addition, we may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. As a result of market conditions, premiums and deductibles for certain of our insurance policies have increased substantially, and could escalate further. For example, following Hurricanes Katrina and Rita, insurance premiums, deductibles and co-insurance requirements increased substantially, and terms were generally less favorable than terms that could be obtained prior to such hurricanes. Insurance market conditions worsened as a result of the losses sustained from Hurricanes Gustav and Ike in September 2008. As a result, we experienced further increases in deductibles and premiums, and further reductions in coverage and limits, with some coverage unavailable at any cost.

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

Pursuant to the authority under the NGPSA and HLPSA, as amended by the PSI Act, the PIPES Act and the 2011 Pipeline Safety Act, PHMSA has established a series of rules requiring pipeline operators to develop and implement integrity management programs for gas transmission and hazardous liquid 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. 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 intrastate gathering and transmission lines. We currently estimate an average annual cost of $2.3 million between 2014 and 2016 to implement pipeline integrity management program testing along certain segments of our natural gas and NGL pipelines. This estimate does not include the costs, if any, of any repair, remediation, preventative or mitigating actions that may be determined to be necessary as a result of the testing program, which costs could be substantial. At this time, we cannot predict the ultimate cost of compliance with applicable pipeline integrity management regulations, as the cost will vary significantly depending on the number and extent of any repairs found to be necessary as a result of the pipeline integrity testing. We will continue our pipeline integrity testing programs to assess and maintain the integrity of our pipelines. The results of these tests could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines.

Moreover, changes to pipeline safety laws by Congress and regulations by PHMSA that result in more stringent or costly safety standards could have a significant adverse effect on us and similarly situated midstream operators. For instance, in August 2011, PHMSA published an advance notice of proposed rulemaking in which the agency sought public comment on a number of changes to regulations governing the safety of gas transmission pipelines and gathering lines, including, for example, revisions to the definitions of “high consequence areas” and “gathering lines” and strengthening integrity management requirements as they apply to existing regulated operators and to currently exempt operators should certain exemptions be removed. PHMSA continues to evaluate the public comments received with respect to more stringent integrity management programs and recently, pursuant to one of the requirements in the 2011 Pipeline Safety Act, published a proposed rulemaking on August 1, 2013, seeking comments on whether an expansion of high consequence areas would mitigate the need for class location requirements that have been used in the past primarily to differentiate risk along a pipeline.

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

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

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

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

Failure to comply with existing or new environmental laws or regulations or an accidental release of hazardous substances, hydrocarbons or wastes into the environment may cause us to incur significant costs and liabilities.

Our operations are subject to stringent federal, regional, state and local environmental laws and regulations governing the discharge of pollutants into the environment or otherwise relating to environmental protection. These laws and regulations may impose numerous obligations that are applicable to our operations, including acquisition of a permit before conducting regulated activities; restrictions on the types, quantities and concentration of materials that can be released into the environment; limitation or prohibition of construction and operating activities in environmentally sensitive areas such as wetlands, urban areas, wilderness regions and other protected areas; requiring capital expenditures to comply with pollution control requirements and imposition of substantial liabilities for pollution resulting from our operations. Numerous governmental authorities, such as the EPA and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, which can often require difficult and costly actions. Failure to comply with these laws and regulations or any newly adopted laws or regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties or other sanctions, the imposition of remedial obligations and the issuance of orders enjoining future operations or imposing additional compliance requirements on such 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 disposed or otherwise released, even under circumstances where the substances, hydrocarbons or waste have been released by a predecessor operator. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by noise, odor or the release of hazardous substances, hydrocarbons or waste products into the environment.

There is inherent risk of incurring environmental costs and liabilities in connection with our operations due to our handling of natural gas, NGLs, crude oil and other petroleum products, because of air emissions and product-related discharges arising out of our operations, and as a result of historical industry operations and waste disposal practices. For example, an accidental release from one of our facilities could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury, natural resource and property damages and fines or penalties for related violations of environmental laws or regulations. Moreover, stricter laws, regulations or enforcement policies could significantly increase our operational or compliance costs and the cost of any remediation that may become necessary. Additionally, environmental groups have, from time to time, advocated increased regulation on the issuance of drilling permits for new oil or gas wells in areas where we operate, including the Barnett Shale area. 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 our natural gas customers' operating and compliance costs as well as reduce the rate of production of natural gas or crude oil from operators with whom we have a business relationship, which could have a material adverse effect on our results of operations and cash flows.

Increased regulation of hydraulic fracturing could result in reductions or delays in drilling and completing new oil and natural gas wells, which could adversely impact our revenues by decreasing the volumes of natural gas, NGLs or crude oil through our facilities and reducing the utilization of our assets.

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 the EPA has asserted limited regulatory authority over hydraulic fracturing, and has indicated it might seek to further expand its regulation of hydraulic fracturing. Also, the Bureau of Land Management has proposed regulations applicable to hydraulic fracturing conducted on federal and Indian oil and gas leases. 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. In addition, local governments may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. If new or more stringent federal, state or local legal restrictions related to the hydraulic fracturing process are adopted in areas where our oil and natural gas exploration and production customers operate, those customers could incur potentially significant added costs to comply with such requirements and experience delays or curtailment in the pursuit of exploration, development or production activities, which could reduce demand for our gathering, processing and fractionation services. 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, the EPA and the U.S. Department of Energy. 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 our customers, and thus reduce demand for our midstream services.

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

With the exception of our interest in VGS, our operations are generally exempt from FERC regulation under the NGA, but FERC regulation still affects our non-FERC jurisdictional businesses and the markets for products derived from these businesses, including certain FERC reporting and posting requirements in a given year. We believe that the natural gas pipelines in its gathering systems meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of substantial, ongoing litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress. In addition, the courts have determined that certain pipelines that would otherwise be subject to the ICA are exempt from regulation by FERC under the ICA as proprietary lines. The classification of a line as a proprietary line is a fact-based determination subject to FERC and court review. Accordingly, the classification and regulation of some of our gathering facilities and transportation pipelines may be subject to change based on future determinations by FERC, the courts or Congress.

The crude oil pipeline system that is part of the Badlands assets has qualified for a temporary waiver of applicable FERC regulatory requirements under the ICA based on current circumstances. Such waivers are subject to revocation, however, and should the pipeline's circumstances change, FERC could, either at the request of other entities or on its own initiative, assert that some or all of the transportation on this pipeline system is within its jurisdiction. In the event that FERC were to determine that this pipeline system no longer qualified for a waiver, we would likely be required to file a tariff with FERC, provide a cost justification for the transportation charge, and provide service to all potential shippers without undue discrimination. Such a change in the jurisdictional status of transportation on this pipeline could adversely affect our results of operations.

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

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

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

Under the Energy Policy Act of 2005, FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1 million per day for each violation and disgorgement of profits associated with any violation. While our systems other than VGS have not been regulated by FERC as a natural gas company under the NGA, FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional facilities to FERC annual reporting and daily scheduled flow and capacity posting requirements. Additional rules and legislation pertaining to those and other matters may be considered or adopted by FERC from time to time. Failure to comply with those regulations in the future could subject us to civil penalty liability. For more information regarding regulation of our operations, see "Item 1. Business—Regulation of Operations."

The adoption of climate change legislation or regulations restricting emissions of GHGs could result in increased operating costs and reduced demand for the products and services we provide.

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 certain large stationary sources, 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 reporting of GHG emissions from specified onshore and offshore production facilities and onshore processing, transmission and storage facilities in the United States on an annual basis, which include certain of our operations. While Congress has from time to time considered adopting legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs. The adoption of any legislation or regulations that requires reporting of GHGs or otherwise restricts emissions of GHGs from our equipment and operations could require us to incur significant added costs to reduce emissions of GHGs or could adversely affect demand for the natural gas and NGLs we gather and process or fractionate. Moreover, if Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on operations and reduce demand for refined products, which could adversely affect the services we provide.

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

The 2011 Pipeline Safety Act is the most recent federal legislation to amend the NGPSA and HLPSA pipeline safety laws, requiring increased safety measures for gas and hazardous liquids transportation pipelines. Among other things, the 2011 Pipeline Safety Act directs the Secretary of Transportation to promulgate rules or standards relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation, testing to confirm that the material strength of certain pipelines is above 30% of specified minimum yield strength, 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 rules thereunder or any issuance or reinterpretation of guidance by PHMSA or any state agencies with respect thereto could require us to install new or modified safety controls, pursue additional capital projects or conduct maintenance programs on an accelerated basis, any or all of which tasks could result in our incurring increased operating costs that could be significant and have a material adverse effect on our results of operations or financial position. For example, PHMSA and one or more state regulators, including the RRC, have in the recent past, expanded the scope of their regulatory inspections to include certain in-plant equipment and pipelines found within NGL fractionation facilities and associated storage facilities, in order to assess compliance of such equipment and pipelines with hazardous liquid 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 legal challenges are unsuccessful, midstream operators of NGL fractionation facilities and associated storage facilities subject to such inspection may be required to make operational changes or modifications at their facilities to meet standards beyond current OSHA PSM and EPA RMP requirements, which changes or modifications may result in additional capital costs, possible operational delays and increased costs of operation that, in some instances, may be significant.

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

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

In October 2011, the CFTC issued regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. The initial position limits rule was vacated by the United States District Court for the District of Columbia in September 2012. However, in November 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time.

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing and the associated rules also will require us, in connection with covered derivative activities, to comply with clearing and trade-execution requirements or take steps to qualify for an exemption to such requirements. Although we expect to qualify for the end-user exception from the mandatory clearing requirements for swaps entered to hedge our commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. In addition, for uncleared swaps, the CFTC or federal banking regulators may require end-users to enter into credit support documentation and/or post initial and variation margin. Posting of collateral could impact liquidity and reduce cash available to us for capital expenditures, therefore reducing our ability to execute hedges to reduce risk and protect cash flows. The proposed margin rules are not yet final, and therefore the impact of those provisions to us is uncertain at this time.

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

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

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

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

Our interstate common carrier liquids 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 we maintain tariffs on file with FERC for each of these pipelines. Those tariffs set forth the rates we charge for providing transportation services as well as the rules and regulations governing these services. The ICA requires, among other things, that rates on interstate common carrier pipelines be “just and reasonable” and nondiscriminatory. All shippers on these pipelines are our subsidiaries.

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

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

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

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

Risks Inherent in an Investment in Us

Cash distributions are not guaranteed and may fluctuate with our performance and the establishment of financial reserves.

Because distributions on the common units are dependent on the amount of cash we generate, distributions may fluctuate based on our performance. The actual amount of cash that is available to be distributed each quarter will depend on numerous factors, some of which are beyond our control and the control of our general partner. Cash distributions are dependent primarily on cash flow, including cash flow from financial reserves and working capital borrowings, and not solely on profitability, which is affected by non-cash items. Therefore, cash distributions might be made during periods when we record losses and might not be made during periods when we record profits.

In order to make cash distributions at our current distribution rate of $0.7475 per common unit per quarter or $2.99 per common unit per year, we will require available cash for common unit-holders of approximately $84.0 million per quarter or $336.0 million per year, based on the number of common units outstanding as of January 24, 2014. We may not have sufficient available cash from operating surplus each quarter to enable us to make cash distributions at our current distribution rate under our cash distribution policy. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the fees we charge and the margins we realize for our services;
- the prices of, levels of production of and demand for, natural gas, NGLs and crude oil;

- the volume of natural gas we gather, treat, compress, process, transport and sell and the volume of NGLs we process or fractionate and sell;
- the relationship between natural gas and NGL prices;
- cash settlements of hedging positions;
- the level of competition from other midstream energy companies;
- the level of our operating and maintenance and general and administrative costs; and
- prevailing economic conditions.

In addition, the actual amount of cash we will have available for distribution will depend on other factors, some of which are beyond our control, including:

- the level of capital expenditures we make;
- our ability to make borrowings under our credit facility to pay distributions;
- our ability to sell accounts receivable and make borrowings under our Securitization Facility;
- the cost of acquisitions;
- our debt service requirements and other liabilities;
- fluctuations in our working capital needs;
- general and administrative expenses, including expenses we incur as a result of being a public company;
- restrictions on distributions contained in our debt agreements; and
- the amount of cash reserves established by our general partner for the proper conduct of our business.

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

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

- neither our partnership agreement nor any other agreement requires Targa to pursue a business strategy that favors us. Targa's directors and officers have a fiduciary duty to make decisions in the best interests of the owners of Targa, which may be contrary to our interests; and
- our general partner is allowed to take into account the interests of parties other than us, such as Targa or its owners, in resolving conflicts of interest.

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

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

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

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

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

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

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

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

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

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

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

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

Cost reimbursements due to our general partner for services provided, which will be determined by our general partner, will be substantial and will reduce our cash available for distribution to you.

Under Delaware partnership law, our general partner has unlimited liability for our obligations, such as our debts and environmental liabilities, except for our contractual obligations that are expressly made without recourse to our general partner. To the extent our general partner incurs obligations on our behalf, we are obligated to reimburse or indemnify our general partner. If we are unable or unwilling to reimburse or indemnify our general partner, our general partner may take actions to cause us to make payments on these obligations and liabilities. Any such payments could reduce the amount of cash otherwise available for distribution to our unitholders.

Holders of our common units have limited voting rights and are not entitled to elect our general partner or its directors.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Unitholders will not elect our general partner or our general partner's board of directors and have no right to elect our general partner or our general partner's board of directors on an annual or other continuing basis. The board of directors of our general partner is chosen by Targa. Furthermore, if the unitholders are dissatisfied with the performance of our general partner, they have little ability to remove our general partner. As a result of these limitations, the price at which the common units trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

We may issue additional units without unitholder approval, which would dilute existing ownership interests.

Our partnership agreement does not limit the number of additional limited partner interests that we may issue at any time without the approval of our unitholders. The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:

- our unitholders' proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

Affiliates of our general partner may sell common units in the public markets, which sales could have an adverse impact on the trading price of the common units.

As of February 10, 2014, Targa and its affiliates beneficially held 13,344,415 common units. The sale of these units in the public markets could have an adverse impact on the price of the common units.

Our general partner may elect to cause us to issue Class B units to it in connection with a resetting of the target distribution levels related to our general partner's incentive distribution rights without the approval of the conflicts committee of our general partner or holders of our common units. This ability may result in lower distributions to holders of our common units in certain situations.

Our general partner has the right, when it has received incentive distributions at the highest level to which it is entitled (48%) for each of the prior four consecutive fiscal quarters, to reset the initial cash target distribution levels at higher levels based on the distribution at the time of the exercise of the reset election. Following a reset election by our general partner, the minimum quarterly distribution amount will be reset to an amount equal to the average cash distribution amount per common unit for the two fiscal quarters immediately preceding the reset election (such amount is referred to as the "reset minimum quarterly distribution"), and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution amount.

In connection with resetting these target distribution levels, our general partner will be entitled to receive Class B units. The Class B units will be entitled to the same cash distributions per unit as our common units and will be convertible into an equal number of common units. The number of Class B units to be issued will be equal to that number of common units whose aggregate quarterly cash distributions equaled the average of the distributions to our general partner on the incentive distribution rights in the prior two quarters. We anticipate that our general partner would exercise this reset right in order to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per common unit without such conversion; however, it is possible that our general partner could exercise this reset election at a time when it is experiencing or may be expected to experience declines in the cash distributions it receives related to its incentive distribution rights and may therefore desire to be issued our Class B units, which are entitled to receive cash distributions from us on the same priority as our common units, rather than retain the right to receive incentive distributions based on the initial target distribution levels. As a result, a reset election may cause our common unitholders to experience dilution in the amount of cash distributions that they would have otherwise received had we not issued new Class B units to our general partner in connection with resetting the target distribution levels related to our general partner's incentive distribution rights.

Increases in interest rates could adversely impact our unit price and our ability to issue additional equity to make acquisitions, for expansion capital expenditures or for other purposes.

As with other yield-oriented securities, our unit price is impacted by the level of our cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank related yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our units, and a rising interest rate environment could have an adverse impact on our unit price and our ability to issue additional equity to make acquisitions, for expansion capital expenditures or for other purposes.

Our partnership agreement restricts the voting rights of unitholders owning 20% or more of our common units.

Unitholders' voting rights are further restricted by the partnership agreement provision providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of our general partner, cannot vote on any matter. Our partnership agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management.

Control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, our partnership agreement does not restrict the ability of the owners of our general partner from transferring all or a portion of their respective ownership interest in our general partner to a third party. The new owners of our general partner would then be in a position to replace the board of directors and officers of our general partner with its own choices and thereby influence the decisions taken by the board of directors and officers.

Our general partner has a limited call right that may require you to sell your units at an undesirable time and/or price.

If at any time our general partner and its affiliates own more than 80% of our common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price not less than their then-current market price. As a result, you may be required to sell your common units at an undesirable time and/or price and may not receive any return on your investment. You may also incur a tax liability upon a sale of your units. As of December 31, 2013, our general partner and its affiliates own approximately 12.0% of our aggregate outstanding common units.

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

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

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

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

Tax Risks to Common Unitholders

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

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes. A publicly traded partnership such as us may be treated as a corporation for federal income tax purposes unless it satisfies a "qualifying income" requirement. Based on our current operations we believe that we satisfy the qualifying income requirement and will be treated as a partnership. Failing to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity. We have not requested and do not plan to request a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes.

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

At the state level, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income and franchise taxes and other forms of taxation. For example, we are subject to the Texas franchise tax at a maximum effective rate of 0.7% of our gross income apportioned to Texas in the prior year. Imposition of any such tax on us by any other state will reduce the cash available for distribution to you.

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

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our 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 we rely for our 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 an investment in our common units. Any modification to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes.

Our partnership agreement provides that if a law is enacted, or existing law is modified or interpreted in a manner, that subjects us to taxation as a corporation or otherwise subjects us 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 us.

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

Because our unitholders are treated as partners to whom we will allocate taxable income which could be different in amount than the cash we distribute, you may be required to pay federal income taxes and, in some cases, state and local income taxes on your share of our taxable income even if you receive no cash distributions from us. You may not receive cash distributions from us equal to your share of our taxable income or even equal to the actual tax liability resulting from that income.

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

If you sell your common units, you will recognize a gain or loss equal to the difference between the amount realized and your tax basis in those common units. Because distributions in excess of your allocable share of our net taxable income decrease your tax basis in your common units, the amount, if any, of such prior excess distributions with respect to the units you sell will, in effect, become taxable income to you if you sell such units at a price greater than your tax basis in those units, even if the price you receive is less than your original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder’s share of our non-recourse liabilities, if you sell your common units, you may incur a tax liability in excess of the amount of cash you receive from the sale.

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

Investment in our common units by tax-exempt entities, such as individual retirement accounts (“IRAs”), other retirement plans and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be subject to withholding taxes imposed at the highest effective tax rate applicable to such non-U.S. persons and each non-U.S. person will be required to file federal tax returns and pay tax on their share of our taxable income. If you are a tax-exempt entity or a non-U.S. person, you should consult your tax advisor before investing in our common units.

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

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

We treat each purchaser of our common units as having the same tax benefits without regard to the common units actually purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Due to a number of factors, including our inability to match transferors and transferees of our common units, we have adopted depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to you. It also could affect the timing of these tax benefits or the amount of gain from the sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to your tax returns.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. Nonetheless, we allocate certain deductions for depreciation of capital additions based upon the date the underlying property is placed in service. The use of this proration method may not be permitted under existing Treasury Regulations. The U.S. Treasury Department has issued proposed Treasury Regulations that provide a safe harbor pursuant to which a publicly traded partnership may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders. The proposed regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge our proration method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

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

Because there are no specific rules governing the federal tax consequences of loaning a partnership interest, a unitholder whose units are the subject of a securities loan may be considered to have disposed of the loaned units. In that case the unitholder may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan, and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan of their units are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between the general partner and the unitholders. The IRS may challenge this treatment, which could adversely affect the value of our common units.

When we issue additional units or engage in certain other transactions, we will determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and the general partner, which may be unfavorable to such unitholders. Moreover, under our valuation methods, subsequent purchasers of common units may have a greater portion of their Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets and allocations of income, gain, loss and deduction between the general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

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

We will be considered to have terminated our partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. Targa currently owns an approximate 11.5% limited partner interest, a 2% general partner interest and our IDRs. Therefore, a transfer of all or a portion of Targa's direct or indirect interest in us, along with transfers by other unitholders, could result in a termination of our partnership for federal income tax purposes. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest are counted only once.

Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders receiving two Schedules K-1) for one fiscal year and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership for tax purposes. If treated as a new partnership, we would be required to make new tax elections and could be subject to penalties if we are unable to determine in a timely manner that a termination occurred. The IRS has recently announced a relief procedure whereby if a publicly traded partnership that has technically terminated requests, and the IRS grants, special relief, the partnership may be permitted to provide only a single Schedule K-1 to unitholders for the tax year in which the technical termination occurs.

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

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

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

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

We are not a party to any legal proceedings other than legal proceedings arising in the ordinary course of our business. 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 Unitholder Matters and Issuer Purchases of Equity Securities.

Market Information

Our common units are listed on the New York Stock Exchange ("NYSE") under the symbol "NGLS." As of February 7 2014, there were approximately 64 unitholders of record of our common units. This number does not include unitholders whose units are held in trust by other entities. The actual number of unitholders is greater than the number of holders of record. As of February 7, 2014, there were 112,390,094 common units outstanding.

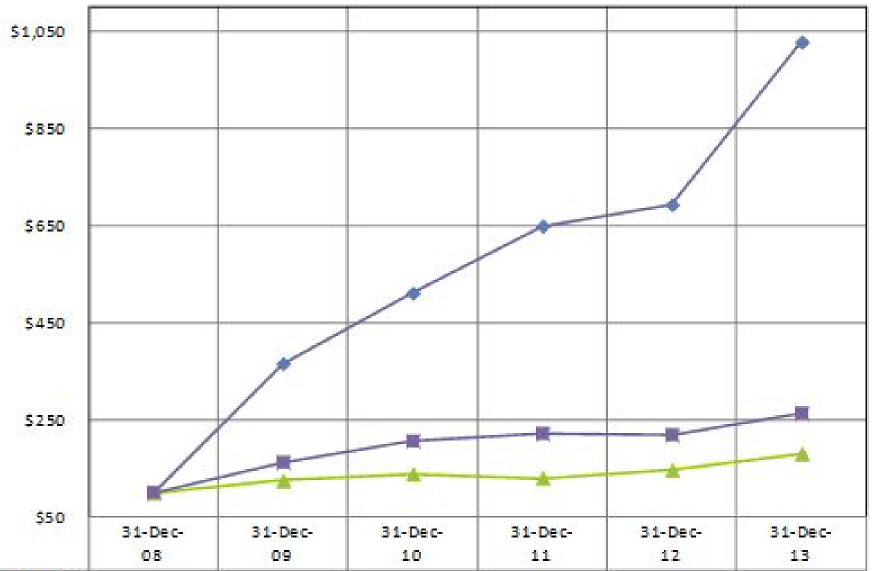
The following table sets forth the high and low sales prices of the common units as reported by the NYSE for the periods indicated:

Quarter Ended	High	Low	Distribution per Common Unit
December 31, 2013	$ 54.25	$ 48.09	$ 0.7475
September 30, 2013	54.13	47.57	0.7325
June 30, 2013	50.87	43.52	0.7150
March 31, 2013	46.25	37.59	0.6975
December 31, 2012	44.75	34.39	0.6800
September 30, 2012	43.50	35.56	0.6625
June 30, 2012	45.42	32.68	0.6425
March 31, 2012	43.48	37.47	0.6225

There is no established trading market for the 2,293,677 general partner units held only by our general partner.

Common Unit Performance Graph

The graph below compares the cumulative return to holders of Targa Resources Partners LP common units, 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 units, the NYSE Index and the MLP Index on December 31, 2008 and (ii) distributions were reinvested on the relevant payment dates. The common unit price performance included in this graph is historical and not necessarily indicative of future common unit price performance.



	31-Dec-08	31-Dec-09	31-Dec-10	31-Dec-11	31-Dec-12	31-Dec-13
Targa Resources Partners LP (NGLS)	$100.00	$365.82	$511.03	$649.24	$693.11	$1,028.92
NYSE Composite Index (NYA)	$100.00	$124.80	$138.34	$129.88	$146.66	$180.65
Alerian MLP Index (AMZ)	$100.00	$161.89	$206.22	$221.19	$218.44	$263.09

Distributions of Available Cash

General

Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all of our available cash to unitholders of record on the applicable record date, as determined by our general partner.

Definition of Available Cash

The term “available cash,” for any quarter, means the sum of all cash and cash equivalents on hand at the end of that quarter, and all additional cash and cash equivalents on hand immediately prior to the date of the distribution of available cash resulting from borrowings for working capital purposes subsequent to the end of that quarter, less the amount of any cash reserves established by our general partner to:

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

Minimum Quarterly Distribution

We intend to make cash distributions to the holders of common units on a quarterly basis in an amount equal to at least the minimum quarterly distribution of $0.3375 per unit, or $1.35 per unit on an annualized basis, to the extent we have sufficient cash from our operations after establishment of cash reserves and payment of fees and expenses, including payments to our general partner. However, there is no guarantee that we will pay the minimum quarterly distribution on the units in any quarter. Even if our cash distribution policy is not modified or revoked, the amount of distributions paid under our policy and the decision to make any distribution is determined by our general partner, taking into consideration the terms of our partnership agreement. The board of directors of our general partner has broad discretion to establish cash reserves that it determines are necessary or appropriate to properly conduct our business. These can include cash reserves for future capital and maintenance expenditures, reserves to stabilize distributions of cash to our unitholders, reserves to reduce debt or, as necessary, reserves to comply with the terms of any of our agreements or obligations. We will be prohibited from making any distributions to unitholders if it would cause an event of default or if an event of default exists under our credit agreement or indentures.

General Partner Interest

Our general partner is currently entitled to 2% of all quarterly distributions that we make prior to our liquidation. As of February 10, 2014 our general partner interest is represented by 2,293,677 general partner units. Our general partner has the right, but not the obligation, to contribute a proportional amount of capital to us to maintain its current general partner interest. The general partner's 2% interest in these distributions will be reduced if we issue additional units in the future and our general partner does not contribute a proportional amount of capital to us to maintain its 2% general partner interest.

Incentive Distribution Rights

Our general partner also currently holds incentive distribution rights that entitle it to receive up to a maximum of 50% of the cash we distribute in excess of $0.50625 per unit per quarter. The maximum distribution of 50% includes distributions paid to our general partner on its general partner interest and assumes that our general partner maintains its general partner interest at 2%. The maximum distribution of 50% does not include any distributions that our general partner may receive on limited partner units that it owns.

The historical distributions paid by us are shown in "Item 7.–Management's Discussion and Analysis of Financial Condition and Results of Operations--Distributions to our Unitholders."

Recent Sales of Unregistered Equity Securities

None.

Repurchase of Equity by Targa Resources Partners LP or Affiliated Purchasers

None.

Item 6. Selected Financial Data.

The following table presents selected historical consolidated financial and operating data of Targa Resources Partners LP for the periods ended, and as of, the dates indicated. We derived this information from our historic "Consolidated Financial Statements" and accompanying notes. The financial data for 2010 and 2009 has been retrospectively adjusted for periods affected by common control accounting under which asset conveyances from Targa during 2009 and 2010 were accounted for as if they had occurred on October 31, 2005, the earliest date of Targa common control. The information in the table below should be read together with, and is qualified in its entirety by reference to, those financial statements and notes of this Annual Report.

	2013	2012	2011	2010	2009
	(In millions, except per unit amounts)				
Statement of operations data:					
Revenues	$ 6,556.2	$ 5,883.6	$ 6,987.1	$ 5,467.0	$ 4,510.2
Income from operations	377.2	342.9	354.9	217.4	194.9
Net income	258.6	203.2	245.5	134.0	7.2
Net income (loss) attributable to Targa Resources Partners LP	233.5	174.6	204.5	109.1	(12.1)
Net income per limited partner unit - basic and diluted	1.19	1.20	1.98	0.92	0.86
Balance sheet data (at end of period):					
Total assets	5,971.4	5,025.7	3,658.0	3,186.4	3,152.7
Long-term allocated debt	-	-	-	-	151.8
Long-term affiliate debt	-	-	-	-	764.8
Long-term debt	2,905.3	2,393.3	1,477.7	1,445.4	908.4
Total owners' equity	2,218.4	1,860.1	1,361.7	1,049.1	728.3
Other:					
Distributions declared per unit	2.89	2.61	2.31	2.13	2.07

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our historical financial statements and notes included in Part IV of this Annual Report

Overview

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

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

Our midstream natural gas and NGL services footprint was established through several acquisitions from Targa, totaling $3.1 billion, that occurred from 2007 through 2010. In these transactions we 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, LSNG treating facilities, pipeline transportation and distribution assets, propane storage and truck terminals primarily located near Houston, Texas and in Lake Charles, Louisiana.

Our Operations

We are a leading United States provider of midstream natural gas and NGL services, with a growing presence in crude oil gathering and petroleum terminaling.

We are engaged in the business of:

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

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

Our Gathering and Processing division includes assets used in the gathering of natural gas produced from oil and gas wells and processing this raw natural gas into merchantable natural gas by extracting NGLs and removing impurities; and assets used for crude oil gathering and terminaling. The Field Gathering and Processing segment's assets are located in North Texas, the Permian Basin of West Texas, 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.

Our Logistics and Marketing division is also referred to as our Downstream Business. Our Downstream Business includes all the activities necessary to convert mixed NGLs into NGL products and provides certain value added services such as the storing, terminaling, distributing and marketing of NGLs and refined petroleum products. It also includes certain natural gas supply and marketing activities in support of our other operations, as well as transporting natural gas and NGLs.

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

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

Other contains the results of our commodity hedging activities included in operating margin.

2013 Developments

Badlands Expansion Program

On January 1, 2013, we assumed operational control of the Badlands assets in the Williston Basin of North Dakota and commenced integration activities. The Badlands operational results are included as part of the Field Gathering and Processing segment.

During 2013, we invested approximately $250 million to expand the gathering and processing capabilities of Badlands. We added an additional 20 MMcf/d natural gas processing plant, and increased our crude gathering and natural gas gathering and processing operations substantially with the addition of pipelines and associated oil and gas facilities. During 2014 we anticipate that we will invest another $180 million for further expansion of its gathering and processing assets.

The acquisition agreement also provided for a contingent payment of $50 million conditioned on achieving stipulated crude gathering volumes by mid-2014. Management does not believe that those thresholds will be achieved during the contingency period. At December 31, 2012, based on a probability-based model measuring the likelihood of meeting the thresholds, we recorded a $15.3 million accrued liability representing the fair value of this contingent consideration. During 2013, the contingent consideration was re-estimated to be $0, resulting in the elimination of the contingent liability.

Cedar Bayou Fractionators Train 4

In August 2013, we commissioned an additional fractionator, Train 4, at CBF. This expansion added 100 MBbl/d of fractionation capacity at CBF. The gross cost of Train 4 was approximately $385 million (our net cost was approximately $345 million).

International Export Project

In September 2013, we commissioned Phase I of our international export expansion project, which includes facilities both at our Mont Belvieu facility and at our Galena Park Marine Terminal near Houston, Texas. Phase I of this project expanded our export capability to approximately 3.5 to 4 MMBbl per month of propane and/or butane. Included in our Phase I expansion is the capability to export international grade low ethane propane. With the completion of Phase I, we also added capabilities to load VLGC vessels in addition to the small and medium-sized export vessels that we load for export. Construction is underway to further expand our propane and butane international export capacity by approximately 2 MMBbl per month, with an expected completion of Phase II in the third quarter of 2014. We expect that the total cost of both phases of our international export project to be approximately $480 million.

North Texas Longhorn Plant

We started construction of a new 200 MMcf/d cryogenic processing plant for North Texas to meet increasing production and continued producer activity, with an anticipated completion in the second quarter of 2014. We expect to invest an estimated $150 million for the plant and associated projects.

SAOU High Plains Plant

We started construction of a new 200 MMcf/d cryogenic processing plant and related gathering and compression facilities for SAOU to meet increasing production and continued producer activity on the eastern side of the Permian Basin, with an anticipated completion date in mid-2014. We expect to invest an estimated $225 million for the plant and associated projects.

Accounts Receivable Securitization Facility

In January 2013, we entered into a Securitization Facility that provides up to $200 million of borrowing capacity at commercial paper or LIBOR market index rates plus a margin through January 2014. Under this Securitization Facility, one of our consolidated subsidiaries (Targa Liquids Marketing and Trade LLC or "TLMT") sells or contributes 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 this 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 or us. Any excess receivables are eligible to satisfy the claims of creditors of TLMT or us.

In December 2013, we entered into an amendment to our Securitization Facility to increase the borrowing capacity to $300 million and extend the termination date to December 12, 2014. As of December 31, 2013, total funding under this Securitization Facility was $279.7 million.

Other Financing Activities

In 2012, we 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 $300 million of debt or equity securities (the "2012 Shelf"). In August 2012, we entered into an Equity Distribution Agreement (the "2012 EDA") with Citigroup Global Markets Inc. ("Citigroup") pursuant to which we may sell, at its option, up to an aggregate of $100 million of its common units through Citigroup, as sales agent, under the 2012 Shelf. During 2012, there were no sales of common units pursuant to this program. During 2013, we issued 2,420,046 common units under the 2012 EDA, receiving net proceeds of $94.8 million. Targa contributed $2.0 million to maintain its 2% general partner interest.

In March 2013, we entered into a second EDA under the 2012 Shelf ("March 2013 EDA") with Citigroup, Deutsche Bank Securities Inc. ("Deutsche Bank"), Raymond James & Associates, Inc. ("Raymond James") and UBS Securities LLC ("UBS"), as our sales agents, pursuant to which we may sell, at our option, up to an aggregate of $200 million of its debt or equity securities. During 2013, we issued 4,204,751 common units under the March 2013 EDA, receiving net proceeds of $197.5 million. Targa contributed $4.1 million to maintain its 2% general partner interest. The 2012 Shelf expires in August 2015.

In April 2013, we filed with the SEC a universal shelf registration statement (the "April 2013 Shelf"), which provides us with the ability to offer and sell an unlimited amount of debt and equity securities, subject to market conditions and our capital needs. The April 2013 Shelf expires in April 2016. There was no activity under the April 2013 Shelf during the year ended December 31, 2013.

In May 2013, we privately placed $625.0 million in aggregate principal amount of 4¼% Senior Notes due 2023 (the "4¼% Notes"). The 4¼% Notes resulted in approximately $618.1 million of net proceeds, which were used to reduce borrowings under the TRP Revolver and for general partnership purposes.

In June 2013, we redeemed $100 million of the outstanding 6⅜% Senior Notes due 2022 (the "6⅜% Notes") at a redemption price of 106.375% plus accrued interest through the redemption date. The redemption resulted in a $7.4 million loss, including the write-off of unamortized debt issue costs.

In July 2013, we redeemed the outstanding balance of the 11¼% Senior Notes due 2017 (the "11¼% Notes") at a price of 105.625% plus accrued interest through July 15, 2013. The redemption resulted in a $7.4 million loss, including the write-off of unamortized debt issue costs.

In July 2013, we filed with the SEC a universal shelf registration statement (the “July 2013 Shelf”) that allows us to issue up to an aggregate of $800 million of debt or equity securities. The July 2013 Shelf expires in August 2016.

In August 2013, we entered into an Equity Distribution Agreement under our July 2013 Shelf (the “August 2013 EDA”) with Citigroup, Deutsche Bank, Morgan Stanley & Co. LLC, Raymond James, RBC Capital Markets, LLC, UBS and Wells Fargo Securities, LLC, as our sales agents, pursuant to which we may sell, at our option, up to an aggregate of $400 million of our common units. During the year ended December 31, 2013, we issued 4,529,641 common units under the August 2013 EDA, receiving net proceeds of $225.6 million, which was used to reduce borrowings under the TRP Revolver and for general partnership purposes. Targa contributed $4.7 million to us to maintain its 2% general partner interest. Based upon market conditions and our capital needs, at our option, we can sell additional common units up to an aggregate amount of $172.0 million under this agreement.

During the year ended December 31, 2013, pursuant to both the 2012 Shelf and 2013 Shelf, we issued a total of 11,154,438 common units representing total net proceeds of $517.9 million, which were used to reduce borrowings under the TRP Revolver and for general partnership purposes. Targa contributed $10.8 million to maintain its 2% general partner interest during this period.

Recent Accounting Pronouncements

In January 2013, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) No. 2013-01, *Balance Sheet (Topic 210): Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities*, which clarifies that ASU No. 2011-11, *Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities*, applies to financial instruments or derivative transactions accounted for under Accounting Standards Codification (“ASC”) Topic 815. We currently present our derivative assets and liabilities gross on our statement of financial position. The amendments require disclosure of both gross and net amounts of derivative assets and liabilities that are subject to master netting arrangements with counterparties. We have provided additional disclosures regarding the gross and net amounts of derivative assets and liabilities in Note 13 of the “Consolidated Financial Statements.”

In February 2013, the FASB issued ASU No. 2013-02, *Comprehensive Income (Topic 220): Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income*. The amendment, required to be applied prospectively for reporting periods beginning after December 15, 2012, requires entities to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line item of net income. Our financial statement presentation complies with this standards update.

Factors That Significantly Affect Our Results

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

Commodity Prices

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

Average Quarterly & Annual Prices	Natural Gas $/MMBtu (1)	Illustrative Targa NGL $/gal (2)	Crude Oil $/Bbl (3)
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**
2011			
4th Quarter	$ 3.54	$ 1.37	$ 91.88
3rd Quarter	4.20	1.37	89.54
2nd Quarter	4.32	1.36	102.34
1st Quarter	4.11	1.23	94.60
2011 Average	**4.04**	**1.33**	**94.59**

(1) Natural gas prices are based on average quarterly and annual prices from Henry Hub I-FERC commercial index prices.
(2) NGL prices are based on quarterly and annual averages of prices from Mont Belvieu 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 and annual averages of daily prices from West Texas Intermediate commercial index prices as measured on the NYMEX.

Contract Terms, Contract Mix and the Impact of Commodity Prices

Because of the potential for significant volatility of natural gas and NGL prices, the contract mix of our Gathering and Processing division, other than fee-based contracts in Badlands and certain other gathering and processing services, can have a material impact on our profitability, especially those contracts that create direct exposure to changes in energy prices by paying us for gathering and processing services with a portion of the commodities handled ("equity volumes").

Contract terms in the Gathering and Processing division are based upon a variety of factors, including natural gas and crude quality, geographic location, competitive commodities and the pricing environment at the time the contract is executed, and customer requirements. Our gathering and processing contract mix and, accordingly, our exposure to crude, natural gas and NGL prices may change as a result of producer preferences, competition and changes in production as wells decline at different rates or are added, our expansion into regions where different types of contracts are more common and other market factors. For example, our Badlands crude and natural gas contracts are essentially 100% fee-based.

The contract terms and contract mix of our Downstream Business can also have a significant impact on our results of operations. During periods of low relative demand for available fractionation capacity, rates were low and frac-or-pay contracts were not readily available. The current demand for fractionation services has grown resulting in increases in fractionation fees and contract term. In addition, reservation fees are required. Increased demand for export services also supports fee-based contracts. Contracts in the Logistics Assets segment are primarily fee-based arrangements while the Marketing and Distribution segment includes both fee-based and percent-of-proceeds contracts.

Impact of Our Commodity Price Hedging Activities

In an effort to reduce the variability of our cash flows, we have hedged the commodity price associated with a portion of our expected natural gas equity volumes through 2016 and our NGL and condensate equity volumes through 2014 by entering into derivative financial instruments including swaps. With these arrangements, we have attempted to mitigate some of our exposure to commodity price movements with respect to our forecasted volumes for these periods. We actively manage the Downstream Business product inventory and other working capital levels to reduce exposure to changing NGL prices. For additional information regarding our hedging activities, see “Item 7A. Quantitative and Qualitative Disclosures About Market Risk— Commodity Price Risk.”

Operating Expenses

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

General and Administrative Expenses

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

General Trends and Outlook

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

Demand for Our Services

Fluctuations in energy prices can affect production rates and investments by third parties in the development of oil and natural gas reserves. Generally, drilling and production activity will increase as energy prices increase. We believe that the current strength of oil, condensate and NGL prices as compared to natural gas prices has caused producers in and around our gathering and processing areas of operation to focus their drilling programs on regions rich in liquid forms of hydrocarbons. This focus is reflected in increased drilling permits and higher rig counts in these areas, and we expect these activities to lead to higher natural gas and crude oil volumes in the Field Gathering and Processing segment over the next several years. While we expect demand for NGL products to remain strong, a reduction in demand for NGL products, or a significant increase in NGL product supply relative to this demand, could impact our business. Increases in demand for international grade propane, along with expansion in the petrochemical industry, which relies on ethane as a feedstock, point towards sustained demand for our terminaling and storage services in the Downstream Business. Producer activity in areas rich in oil, condensate and NGLs is currently generating increased demand for our fractionation services and for related fee-based services provided by our Downstream Business. While we expect development activity to remain robust with respect to oil and liquids-rich gas development and production, currently depressed natural gas prices have resulted in reduced activity levels surrounding comparatively dry natural gas reserves, whether conventional or unconventional.

Commodity Prices

There has been and we believe there will continue to be significant volatility in commodity prices and in the relationships among NGL, crude oil and natural gas prices. In addition, the volatility and uncertainty of natural gas, crude oil and NGL prices impact drilling, completion and other investment decisions by producers and ultimately supply to our systems.

Our operating income generally improves in an environment of higher natural gas, NGL and condensate prices, primarily as a result of our percent-of-proceeds contracts. Our processing profitability is largely dependent upon pricing, the supply of and market demand for natural gas, NGLs and condensate, which are beyond our control and have been volatile. In a declining commodity price environment, without taking into account our hedges, we will realize a reduction in cash flows under our percent-of-proceeds contracts proportionate to average price declines. We have attempted to mitigate our exposure to commodity price movements by entering into hedging arrangements. For additional information regarding our hedging activities, see “Item 7A. Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk.”

Volatile Capital Markets

We are dependent on our ability 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 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 execute growth plans. Prolonged periods of low commodity prices or volatile capital markets may impact our 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 our 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 “Risk Factors—Increased regulation of hydraulic fracturing could result in reductions or delays in drilling and completing new oil and natural gas wells, which could adversely impact our revenues by decreasing the volumes of natural gas, NGLs or crude oil through our facilities and reducing the utilization of our assets.” Similarly, the forthcoming rules and regulations of the CFTC may limit our ability or increase the cost to use derivatives, which could create more volatility and less predictability in our results of operations. Please read “Risk Factors—The recent adoption of derivatives legislation by the United States Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other types of risks associated with our business.”

Distributions to our Unitholders

We intend to make cash distributions to our unitholders and our general partner of at least the minimum quarterly distribution rate of $0.3375 per common unit per quarter ($1.35 per common unit on an annualized basis). As of December 31, 2013, such annual minimum amounts would have been approximately $153.3 million. In every quarter since the fourth quarter of 2007, we have paid quarterly distributions greater than the minimum quarterly distribution rate.

For the year ended December 31, 2013 compared to 2012, total distributions paid increased by $112.0 million. For the year ended December 31, 2012 compared to 2011, total distributions increased by $60.1 million. The following table shows the distributions for the years presented:

		Distributions				
		Limited Partners	General Partner			Distributions per Limited Partner Unit
Three Months Ended	Date Paid or to be Paid	Common	Incentive	2%	Total	
		(In millions, except per unit amounts)				
2013						
December 31, 2013	February 14, 2014	$ 84.0	$ 29.5	$ 2.3	$ 115.8	$ 0.7475
September 30, 2013	November 14, 2013	79.4	26.9	2.2	108.5	0.7325
June 30, 2013	August 14, 2013	75.8	24.6	2.0	102.4	0.7150
March 31, 2013	May 15, 2013	71.7	22.1	1.9	95.7	0.6975
2012						
December 31, 2012	February 14, 2013	$ 69.0	$ 20.1	$ 1.8	$ 90.9	$ 0.6800
September 30, 2012	November 14, 2012	59.1	16.1	1.5	76.7	0.6625
June 30, 2012	August 14, 2012	57.3	14.4	1.5	73.2	0.6425
March 31, 2012	May 15, 2012	55.5	12.7	1.4	69.6	0.6225
2011						
December 31, 2011	February 14, 2012	$ 53.7	$ 11.0	$ 1.3	$ 66.0	$ 0.6025
September 30, 2011	November 14, 2011	49.4	8.8	1.2	59.4	0.5825
June 30, 2011	August 12, 2011	48.3	7.8	1.2	57.3	0.5700
March 31, 2011	May 13, 2011	47.3	6.8	1.1	55.2	0.5575

How We Evaluate Our Operations

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

Our profitability is also impacted by fee-based revenues. Our growth strategy, based on expansion of existing facilities as well as third-party acquisitions of businesses and assets, has been increasing the percentage of our revenues that are fee-based. Fixed fees for services such as fractionation, storage, terminaling and crude oil gathering are not directly tied to changes in market prices for commodities.

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

Throughput Volumes, Facility Efficiencies and Fuel Consumption

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

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

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

Operating Expenses

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

Capital Expenditures

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

Gross Margin

We define gross margin as revenues less purchases. It is impacted by volumes and commodity prices as well as by our contract mix and commodity hedging program. We define Gathering and Processing gross margin as total operating revenues from (1) the sale of natural gas, condensate and NGLs (2) natural gas and crude oil gathering and service fee revenues and (3) settlement gains and losses on commodity hedges, less product purchases, which consist primarily of producer payments and other natural gas purchases. Logistics Assets gross margin consists primarily of service fee revenue. Gross margin for Marketing and Distribution equals total revenue from service fees, NGL and natural gas sales, less cost of sales, which consists primarily of NGL and natural gas purchases, transportation costs and changes in inventory valuation. The gross margin impacts of cash flow hedge settlements are reported in Other.

Operating Margin

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

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

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;

- our operating performance and return on capital as compared to other companies in the midstream energy sector, without regard to financing or capital structure; and

- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

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

Management compensates for the limitations of gross margin and operating margin as analytical tools by reviewing the comparable GAAP measure, understanding the differences between the measures and incorporating these insights into its decision-making processes.

Adjusted EBITDA

We define Adjusted EBITDA as net income attributable to Targa Resources Partners LP before: interest; income taxes; depreciation and amortization; 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 and the non-controlling interest portion of depreciation and amortization expenses. Adjusted EBITDA is used as a supplemental financial measure by us and by external users of our financial statements such as investors, commercial banks and others. The economic substance behind our use of Adjusted EBITDA is to measure the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and make distributions to our investors.

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

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

Distributable Cash Flow

We define distributable cash flow as net income attributable to Targa Resources Partners LP plus depreciation and amortization, 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 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 us and by external users of our financial statements, such as investors, commercial banks and research analysts, to compare basic cash flows generated by us (prior to the establishment of any retained cash reserves by the board of directors of our general partner) to the cash distributions we expect to pay our unitholders. Using this metric, management and external users of our financial statements can quickly compute the coverage ratio of estimated cash flows to cash distributions. Distributable cash flow is also an important financial measure for our unitholders since it serves as an indicator of our success in providing a cash return on investment. Specifically, this financial measure indicates to investors whether or not we are generating cash flow at a level that can sustain or support an increase in our quarterly distribution rates. Distributable cash flow is also a quantitative standard used throughout the investment community with respect to publicly-traded partnerships and limited liability companies because the value of a unit of such an entity is generally determined by the unit's yield (which in turn is based on the amount of cash distributions the entity pays to a 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 our results as reported under GAAP. Because distributable cash flow excludes some, but not all, items that affect net income and is defined differently by different companies in our industry, our definition of distributable cash flow may not be comparable to similarly titled measures of other companies, thereby diminishing its utility.

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

Non-GAAP Financial Measures

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

	2013	2012	2011
		(In millions)	
Reconciliation of Targa Resources Partners LP gross margin and operating margin to net income:			
Gross margin	$ 1,177.7	$ 1,004.7	$ 948.1
Operating expenses	(376.2)	(313.0)	(287.0)
Operating margin	801.5	691.7	661.1
Depreciation and amortization expenses	(271.6)	(197.3)	(178.2)
General and administrative expenses	(143.1)	(131.6)	(127.8)
Interest expense, net	(131.0)	(116.8)	(107.7)
Income tax expense	(2.9)	(4.2)	(4.3)
Loss on sale or disposition of assets	(3.9)	(15.6)	(0.2)
Loss on debt redemptions and amendments	(14.7)	(12.8)	-
Change in contingent consideration	15.3	-	-
Other, net	9.0	(10.2)	2.6
Targa Resources Partners LP net income	$ 258.6	$ 203.2	$ 245.5

	2013	2012	2011
		(In millions)	
Reconciliation of net cash provided by Targa Resources Partners LP operating activities to Adjusted EBITDA:			
Net cash provided by operating activities	$ 411.4	$ 465.4	$ 400.9
Net income attributable to noncontrolling interests	(25.1)	(28.6)	(41.0)
Interest expense, net (1)	115.5	99.2	95.3
Loss on debt redemptions and amendments	(14.7)	(12.8)	-
Change in contingent consideration	(15.3)	-	-
Current income tax expense	2.0	2.5	3.5
Other (2)	(5.0)	(6.4)	7.9
Changes in operating assets and liabilities which used (provided) cash:			
Accounts receivable and other assets	230.3	(96.1)	150.3
Accounts payable and other liabilities	(69.9)	91.7	(126.1)
Targa Resources Partners LP Adjusted EBITDA	$ 629.2	$ 514.9	$ 490.8

(1) Net of amortization of debt issuance costs, discount and premium included in interest expense of $15.5 million, $17.6 million and $12.4 million for 2013, 2012 and 2011.
(2) Includes equity earnings from unconsolidated investments – net of distributions, accretion expense associated with asset retirement obligations, amortization of stock-based compensation and gain on sale or disposal of assets.

	2013	2012	2011
		(In millions)	
Reconciliation of Net Income attributable to Targa Resources Partners LP to Adjusted EBITDA:			
Net income attributable to Targa Resources Partners LP	$ 233.5	$ 174.6	$ 204.5
Interest expense, net	131.0	116.8	107.7
Income tax expense	2.9	4.2	4.3
Depreciation and amortization expenses	271.6	197.3	178.2
Loss on sale or disposition of assets	3.9	15.6	-
Loss on debt redemptions and amendments	14.7	12.8	-
Change in contingent consideration	(15.3)	-	-
Risk management activities	(0.5)	5.4	7.2
Noncontrolling interests adjustment (1)	(12.6)	(11.8)	(11.1)
Targa Resources Partners LP Adjusted EBITDA	$ 629.2	$ 514.9	$ 490.8

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

	2013	2012	2011
		(In millions)	
Reconciliation of Net Income attributable to Targa Resources Partners LP to Distributable Cash flow:			
Net income attributable to Targa Resources Partners LP	$ 233.5	$ 174.6	$ 204.5
Depreciation and amortization expenses	271.6	197.3	178.2
Deferred income tax expense	0.9	1.7	0.8
Amortization in interest expense	15.5	17.6	12.4
Loss on debt redemptions and amendments	14.7	12.8	-
Change in contingent consideration	(15.3)	-	-
Loss on sale or disposition of assets	3.9	15.6	-
Risk management activities	(0.5)	5.4	7.2
Maintenance capital expenditures	(79.9)	(67.6)	(81.8)
Other (1)	(4.1)	(3.5)	15.4
Targa Resources Partners LP distributable cash flow	$ 440.3	$ 353.9	$ 336.7

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

Results of Operations

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

	2013	2012	2011	2013 vs. 2012		2012 vs. 2011	
	(In millions, except operating statistics and price amounts)						
Revenues	$ 6,556.2	$ 5,883.6	$ 6,987.1	$ 672.6	11%	$ (1,103.5)	(16%)
Product purchases	5,378.5	4,878.9	6,039.0	499.6	10%	(1,160.1)	(19%)
Gross margin (1)	1,177.7	1,004.7	948.1	173.0	17%	56.6	6%
Operating expenses	376.2	313.0	287.0	63.2	20%	26.0	9%
Operating margin (2)	801.5	691.7	661.1	109.8	16%	30.6	5%
Depreciation and amortization expenses	271.6	197.3	178.2	74.3	38%	19.1	11%
General and administrative expenses	143.1	131.6	127.8	11.5	9%	3.8	3%
Other operating expense	9.6	19.9	0.2	(10.3)	(52%)	19.7	NM
Income from operations	377.2	342.9	354.9	34.3	10%	(12.0)	(3%)
Interest expense, net	(131.0)	(116.8)	(107.7)	(14.2)	12%	(9.1)	(8%)
Equity earnings	14.8	1.9	8.8	12.9	NM	(6.9)	(78%)
Loss on debt redemptions and amendments	(14.7)	(12.8)	-	(1.9)	15%	(12.8)	-
Loss on mark-to-market derivative instruments	-	-	(5.0)	-	-	5.0	100%
Other	15.2	(7.8)	(1.2)	23.0	NM	(6.6)	NM
Income tax expense	(2.9)	(4.2)	(4.3)	1.3	(31%)	0.1	2%
Net income	258.6	203.2	245.5	55.4	27%	(42.3)	(17%)
Less: Net income attributable to noncontrolling interests	25.1	28.6	41.0	(3.5)	(12%)	(12.4)	(30%)
Net income attributable to Targa Resources Partners LP	$ 233.5	$ 174.6	$ 204.5	$ 58.9	34%	$ (29.9)	(15%)
Financial and operating data:							
Financial data:							
Adjusted EBITDA (3)	$ 629.2	$ 514.9	$ 490.8	$ 114.3	22%	$ 24.1	5%
Distributable cash flow (4)	440.3	353.9	336.7	86.4	24%	17.2	5%
Capital expenditures	1,034.5	1,612.9	490.0	(578.4)	(36%)	1,122.9	229%
Operating data:							
Crude oil gathered, MBbl/d	46.9	-	-	46.9	-	-	-
Plant natural gas inlet, MMcf/d (5)(6)	2,110.2	2,098.3	2,162.1	11.9	1%	(63.8)	(3%)
Gross NGL production, MBbl/d	136.8	128.7	123.9	8.1	6%	4.8	4%
Export volumes, MBbl/d (7)	66.6	31.6	17.2	35.0	111%	14.4	84%
Natural gas sales, BBtu/d (6)	928.2	927.6	779.3	0.6	0%	148.3	19%
NGL sales, MBbl/d	316.6	284.5	269.6	32.1	11%	14.9	6%
Condensate sales, MBbl/d	3.5	3.5	3.0	-	0%	0.5	17%

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

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

(3) Adjusted EBITDA is net income attributable to Targa Resources LP before: interest, income taxes, depreciation and amortization, gains or losses on debt repurchases and debt redemptions, early debt extinguishments and asset disposals, non-cash risk management activities related to derivative instruments and changes in the fair value of the Badlands acquisition contingent consideration and the non-controlling interest portion of depreciation and amortization expenses. This is a non-GAAP financial measure and is discussed under "Management's Discussion and Analysis of Financial Condition and Results of Operations – How We Evaluate Our Operations" and "Non-GAAP Financial Measures."

(4) Distributable cash flow is 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 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 is a non-GAAP financial measure and is discussed under "Management's Discussion and Analysis of Financial Condition and Results of Operations – How We Evaluate Our Operations" and "Non-GAAP Financial Measures."

(5) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant, other than in Badlands, where it represents total wellhead gathered volume.
(6) Plant natural gas inlet volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.
(7) Export volumes represent the quantity of NGL products delivered to third party customers at our Galena Park Marine terminal that are destined for international markets.

2013 Compared to 2012

Revenues, including the impact of hedging, increased due to the impact of higher commodity volumes ($446.9 million), higher realized prices on natural gas, condensate, and petroleum products ($261.2 million) and higher fee-based and other revenues ($227.8 million), offset by lower realized prices on NGLs ($263.2 million).

Higher consolidated gross margin in 2013 includes the contribution of our Badlands acquisition. Other favorable gross margin factors were increased volumes from system expansions and higher gas prices in our Field Gathering and Processing segment and higher fractionation fees and increased export activities in our Logistics and Marketing segments. This significant growth in our 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 expansion.

General and administrative expenses increased, reflecting increased compensation related costs to support our expanding business operations.

Other operating expense in 2013 includes the Versado joint venture cost of repairs less amounts covered by insurance ($4.0 million) related to a fire at the Saunders plant. Other operating expense in 2012 reflects a $15.4 million loss due to a write-off of our investment in the Yscloskey joint venture processing plant in Southeastern Louisiana. 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 our Coastal Straddle plants.

The increase in interest expense primarily reflects higher borrowings ($36.2 million), partially offset by the impact of lower effective interest rates ($7.7 million) and increases in capitalized interest attributable to our major expansion projects ($14.4 million).

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

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 11¼% Notes and the redemption of $100 million of the Partnership's 6⅜% Notes.

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

Net income attributable to noncontrolling interests declined during 2013, as the impact of lower earnings at our Versado and VESCO joint ventures more than offset the impact of higher earnings at CBF.

2012 Compared to 2011

Revenues, including the impacts of hedging, decreased due to the impact of lower realized prices on commodities ($1,962.9 million), partially offset by higher commodity sales volumes ($769.6 million) and higher fee-based and other revenues ($89.8 million).

The increase in gross margin reflects lower revenues more than offset by lower product purchases. 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 operating expenses reflects expansion and acquisition activities. See "—Results of Operations—By Reportable Segment" for additional discussion regarding changes in operating expenses.

The increase in depreciation and amortization expenses is attributable to the impact of new assets placed in service as well as assets associated with business acquisitions.

General and administrative expenses increased due to higher compensation and benefits.

Other operating expense in 2012 relates to the Yscloskey plant closure and Hurricane Isaac clean-up and repair costs as discussed above.

The increase in interest expense primarily reflects higher borrowings ($22.3 million), which was offset by the impact of lower effective interest rates ($3.0 million) and increases in capitalized interest that was attributable to our major expansion projects ($10.2 million).

Lower equity earnings from our non-operated GCF equity investment resulted from the planned shutdown of operations associated with 43 MBbl/d capacity expansion project. GCF operations were also affected by start-up issues associated with the expansion.

Losses on a debt redemption and amendment during 2012 are largely attributable to premiums and write-off of debt issue costs in connection with the redemption of the Partnership's 8¼% Senior Notes due 2016 (the "8¼% Notes") and the amendment to the TRP Revolver. See Note 10 of the "Consolidated Financial Statements" of this Annual Report for additional details.

The mark-to-market loss in 2011 was attributable to interest rate swaps that were de-designated as hedging instruments during the second quarter of that year. Consequently, we discontinued hedge accounting on those swaps, and all subsequent changes in fair value settlements were recorded as mark-to-market losses until September 2011 when we terminated all of our interest rate swaps.

The increase in other expenses is attributable to fees and expenses related to completing the Badlands acquisition.

The decrease in net income attributable to noncontrolling interests reflects the impact of the weaker price environment on our Versado and VESCO joint ventures, as well as the disruption of operations at VESCO due to Hurricane Isaac. These factors were partially offset by increased net income at CBF.

Results of Operations—By Reportable Segment

Our operating margins by reportable segment are:

	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Total
			(In millions)			
2013	$ 270.5	$ 85.4	$ 282.3	$ 141.9	$ 21.4	$ 801.5
2012	231.2	115.1	188.3	116.0	41.1	691.7
2011	287.9	174.3	123.1	113.4	(37.6)	661.1

Gathering and Processing Segments

Field Gathering and Processing

	2013	2012	2011	2013 vs. 2012		2012 vs. 2011	
	($ in millions, except operating statistics and price amounts)						
Gross margin	$ 435.7	$ 357.4	$ 403.6	$ 78.3	22%	$ (46.2)	(11%)
Operating expenses	165.2	126.2	115.7	39.0	31%	10.5	9%
Operating margin	$ 270.5	$ 231.2	$ 287.9	$ 39.3	17%	$ (56.7)	(20%)
Operating statistics (1):							
Plant natural gas inlet, MMcf/d (2),(3)							
Sand Hills	155.8	145.2	134.2	10.6	7%	11.0	8%
SAOU	154.1	124.8	111.0	29.3	23%	13.8	12%
North Texas System	292.4	244.5	203.5	47.9	20%	41.0	20%
Versado	156.4	167.4	162.8	(11.0)	(7%)	4.6	3%
Badlands (4)	21.4	-	-	21.4	-	-	-
	780.1	681.9	611.5	98.2	14%	70.4	12%
Gross NGL production, MBbl/d (3)							
Sand Hills	17.5	16.9	15.7	0.6	4%	1.2	8%
SAOU	22.5	19.2	17.4	3.3	17%	1.8	10%
North Texas System	31.1	26.8	22.9	4.3	16%	3.9	17%
Versado	18.9	19.7	18.2	(0.8)	(4%)	1.5	8%
Badlands	1.9	-	-	1.9	-	-	-
	91.9	82.6	74.2	9.3	11%	8.4	11%
Crude oil gathered, MBbl/d	46.9	-	-	46.9	-	-	-
Natural gas sales, BBtu/d (3)	376.3	325.0	285.5	51.3	16%	39.5	14%
NGL sales, MBbl/d	71.4	68.5	59.8	2.9	4%	8.7	15%
Condensate sales, MBbl/d	3.2	3.2	2.8	-	0%	0.4	14%
Average realized prices (5):							
Natural gas, $/MMBtu	3.44	2.60	3.80	0.84	32%	(1.20)	(32%)
NGL, $/gal	0.76	0.87	1.23	(0.11)	(13%)	(0.36)	(29%)
Condensate, $/Bbl	92.89	88.49	91.55	4.40	5%	(3.06)	(3%)

(1) Segment operating statistics include the effect of intersegment amounts, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume during the year and the denominator is the number of calendar days during the year.
(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) Badlands natural gas inlet represents the total wellhead gathered volume.
(5) Average realized prices exclude the impact of hedging settlements presented in Other.

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.

2012 Compared to 2011

The decrease in gross margin was primarily due to lower commodity sales prices, partially offset by higher throughput volumes. The increase in plant inlet volumes was largely attributable to new well connects, particularly North Texas, Sand Hills and SAOU, partially offset by pipeline curtailments and operational issues.

The increase in operating expenses was primarily due to additional compression related expenses due to system expansions and higher system maintenance and repair costs.

Coastal Gathering and Processing

	2013	2012	2011	2013 vs. 2012		2012 vs. 2011	
	($ in millions, except operating statistics and price amounts)						
Gross margin	$ 132.3	$ 162.2	$ 221.6	$ (29.9)	(18%)	$ (59.4)	(27%)
Operating expenses	46.9	47.1	47.3	(0.2)	0%	(0.2)	0%
Operating margin	$ 85.4	$ 115.1	$ 174.3	$ (29.7)	(26%)	$ (59.2)	(34%)
Operating statistics (1):							
Plant natural gas inlet, MMcf/d (2),(3)							
LOU (4)	350.9	260.6	175.7	90.3	35%	84.9	48%
VESCO	515.5	479.6	498.5	35.9	7%	(18.9)	(4%)
Other Coastal Straddles	463.7	676.2	876.4	(212.5)	(31%)	(200.2)	(23%)
	1,330.1	1,416.4	1,550.6	(86.3)	(6%)	(134.2)	(9%)
Gross NGL production, MBbl/d (3)							
LOU	10.2	8.6	7.4	1.6	19%	1.2	16%
VESCO	21.5	22.1	25.9	(0.6)	(3%)	(3.8)	(15%)
Other Coastal Straddles	13.2	15.4	16.5	(2.2)	(14%)	(1.1)	(7%)
	44.9	46.1	49.8	(1.2)	(3%)	(3.7)	(7%)
Natural gas sales, BBtu/d (3)	296.0	298.5	268.4	(2.5)	(1%)	30.1	11%
NGL sales, MBbl/d	41.8	42.5	43.5	(0.7)	(2%)	(1.0)	(2%)
Condensate sales, MBbl/d	0.4	0.3	0.3	0.1	19%	-	0%
Average realized prices:							
Natural gas, $/MMBtu	3.73	2.78	4.02	0.95	34%	(1.24)	(31%)
NGL, $/gal	0.83	0.96	1.31	(0.13)	(14%)	(0.35)	(27%)
Condensate, $/Bbl	104.38	103.57	105.10	0.81	1%	(1.53)	(1%)

(1) Segment operating statistics include intersegment amounts, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume during the year and the denominator is the number of calendar days during the year.
(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 Big Lake processing plant acquired in July 2012.

2013 Compared to 2012

The decrease in gross margin was primarily due to lower NGL prices, less favorable frac spread 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 2012 volumes also reflect the shutdown of Coastal Straddle plant operations during 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.

2012 Compared to 2011

The decrease in gross margin was primarily due to lower commodity sales prices, less favorable frac spread and lower throughput volumes. The decrease in plant inlet volumes was largely attributable to the decline in offshore and off-system supply volumes and planned operational outages at VESCO in the second quarter of 2012, as well as the impact of Hurricane Isaac in the third quarter of 2012 and the post-Isaac shutdown of the Yscloskey plant. The volume decreases were partially offset by increased LOU supply volumes, the July 2012 acquisition of the Big Lake plant and gas purchased for processing at VESCO and Lowry. NGL production and sales at LOU increased on higher throughput volumes, partially offset by lower average system liquids content of the natural gas. Natural gas sales volumes increased due to an increase in demand from industrial customers.

Operating expenses were relatively flat as higher system maintenance and repair costs at VESCO were offset by operating cost reductions attributable to the Yscloskey and Calumet plant shutdowns in 2012.

Logistics and Marketing Segments

Logistics Assets

	2013	2012	2011	2013 vs. 2012		2012 vs. 2011	
	($ in millions, except operating statistics)						
Gross margin	$ 408.2	$ 286.0	$ 221.1	$ 122.2	43%	$ 64.9	29%
Operating expenses	125.9	97.7	98.0	28.2	29%	(0.3)	0%
Operating margin	$ 282.3	$ 188.3	$ 123.1	$ 94.0	50%	$ 65.2	53%
Operating statistics MBbl/d (1):							
Fractionation volumes	287.6	299.2	268.4	(11.6)	(4%)	30.8	11%
LSNG treating volumes	20.1	22.4	15.3	(2.3)	(10%)	7.1	46%
Benzene treating volumes	17.5	19.0	-	(1.5)	(8%)	19.0	-

(1) For all volume statistics presented, the numerator is the total volume during the year and the denominator is the number of calendar days during the year.

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 fuel prices which pass through to operating expenses. 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.

The increase in operating expenses primarily reflects increased power and fuel prices (which have a corresponding impact on fractionating and treating fee revenues); expenses related to the start-up and operations of Train 4 at CBF and increased maintenance costs, partially offset by higher system product gains.

2012 Compared to 2011

The increase in gross margin was primarily due to increased export and storage fee revenue, higher treating volumes, increased petroleum logistics activities and higher fractionation volumes. Export and storage fees increased due to higher export shipments. Treating fees increased due to the operational startup of the benzene treating and de-pentanizer units in the first quarter of 2012 and increased hydrotreating fees associated with increased volumes in 2012. Terminaling gross margin for 2012 improved as a result of the impact of the October 2011 Sound Terminal acquisition. Higher fractionation volumes and fees were primarily attributable to the CBF Train 3 expansion, which came on line in mid-year 2011, partially offset by the impact of lower fuel prices which pass through to expenses.

Operating expenses were essentially flat as favorable system product gains and lower fuel costs (which have a corresponding impact on fractionation revenues) were offset by higher operating costs due to greater hydrotreating, benzene and de-pentanizer unit run-times, higher maintenance activities and the impact of a full twelve months in 2012 of operating costs associated with petroleum logistics operations acquired in April and October of 2011.

Marketing and Distribution

	2013	2012	2011	2013 vs. 2012		2012 vs. 2011	
	(In millions, except operating statistics and price amounts)						
Gross margin	$ 185.2	$ 154.1	$ 156.4	$ 31.1	20%	$ (2.3)	(1%)
Operating expenses	43.3	38.1	43.0	5.2	14%	(4.9)	(11%)
Operating margin	$ 141.9	$ 116.0	$ 113.4	$ 25.9	22%	$ 2.6	2%
Operating statistics (1):							
NGL sales, MBbl/d	318.4	289.8	272.5	28.6	10%	17.3	6%
Average realized prices:							
NGL realized price, $/gal	0.93	0.98	1.34	(0.05)	(5%)	(0.36)	(27%)

(1) Segment operating statistics include intersegment amounts, which have been eliminated from the consolidated presentation. For all volume statistics presented, the numerator is the total volume sold during the year and the denominator is the number of calendar days during the year.

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 of 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.

2012 Compared to 2011

Gross margin decreased primarily due to a much weaker price environment and lower barge activity in 2012, partially offset by increased LPG export activity, increased trucking activity, favorable short-term wholesale propane marketing opportunities and higher NGL and natural gas sales volumes.

Operating expenses decreased due to lower barge activity, partially offset by increased truck operating costs.

Other

	2013	2012	2011	2013 vs. 2012	2012 vs. 2011
			($ in millions)		
Gross margin	$ 21.4	$ 41.1	$ (37.6)	$ (19.7)	$ 78.7
Operating margin	$ 21.4	$ 41.1	$ (37.6)	$ (19.7)	$ 78.7

Other contains the financial effects of our hedging program on operating margin. It typically represents the cash settlements on our derivative contracts. Other also includes deferred gains or losses on previously terminated or de-designated hedge contracts that are reclassified to revenues upon the occurrence of the underlying physical transactions.

The primary purpose of our commodity risk management activities is to manage our exposure to commodity price risk and reduce volatility in our operating cash flow due to fluctuations in commodity prices. We have hedged the commodity price associated with a portion of our expected (i) natural gas equity volumes in Field Gathering and Processing operations and (ii) NGL and condensate equity volumes predominately in Field Gathering and Processing as well as in the LOU portion of the Coastal Gathering and Processing Operations that result from its percent-of-proceeds or liquids processing arrangements by entering into derivative instruments.

The following table provides a breakdown of our hedge revenue by product:

	2013	2012	2011	2013 vs. 2012	2012 vs. 2011
			($ in millions)		
Natural gas	$ 11.2	$ 33.8	$ 21.2	$ (22.6)	$ 12.6
NGL	12.8	9.1	(53.1)	3.7	62.2
Crude oil	(2.6)	(1.8)	(5.7)	(0.8)	3.9
	$ 21.4	$ 41.1	$ (37.6)	$ (19.7)	$ 78.7

Because we are essentially forward-selling a portion of our plant equity volumes, these hedge positions will move favorably in periods of falling prices and unfavorably in periods of rising prices.

Liquidity and Capital Resources

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

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

As of January 31, 2014, our liquidity consisted of the following:

	January 31, 2014
	(In millions)
Cash on hand	$ 133.4
Total availability under the TRP Revolver	1,200.0
Total availability under the Securitization Facility	270.5
	1,603.9
Less: Outstanding borrowings under the TRP Revolver	(365.0)
Outstanding borrowings under the Securitization Facility	(270.5)
Outstanding letters of credit under the TRP Revolver	(95.3)
Total liquidity	$ 873.1

In addition to amounts in the table above, the TRP Revolver allows us to request an additional $300.0 million in commitment increases. We may also issue additional equity or debt securities under our outstanding shelf registration statements to assist us in meeting future liquidity and capital spending requirements (see Notes 10 and 11 of the "Consolidated Financial Statements").

The April 2013 Shelf provides us with the ability to offer and sell an unlimited amount of debt and equity securities, subject to market conditions and our capital needs. The April 2013 Shelf expires in April 2016. As of February 10, 2014, there had been no activity under the April 2013 Shelf.

The July 2013 Shelf allows us to issue up to an aggregate of $800 million of debt or equity securities. The July 2013 Shelf expires in August 2016. As of February 10, 2014, we have the ability to sell additional debt or equity securities up to an aggregate amount of $515.3 million under the July 2013 Shelf.

A portion of our capital resources may be utilized in the form of letters of credit to satisfy certain counterparty credit requirements. While our credit ratings have improved over time, these letters of credit reflect our non-investment grade status, as assigned to us by Moody's Investors Service, Inc. and Standard & Poor's Corporation and counterparties' views of our financial condition and ability to satisfy our performance obligations, as well as commodity prices and other factors. As of December 31, 2013, we had $86.8 million in letters of credit outstanding.

Risk Management

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

Crude oil, NGL and natural gas prices are also volatile. In an effort to reduce the variability of our cash flows, we have entered into derivative instruments to hedge the commodity price associated with a portion of our expected natural gas equity volumes through 2016 and our NGL and condensate equity volumes through 2014. See "Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk." The current market conditions may also impact our ability to enter into future commodity derivative contracts.

Our risk management position has moved from a net asset position of $22.2 million at December 31, 2012 to a net liability position of $4.3 million at December 31, 2013. Aggregate forward prices for commodities are above the fixed prices we currently expect to receive on those derivative contracts, creating this net liability position. We account for derivatives that mitigate commodity price risk as cash flow hedges. Changes in fair value are deferred in other comprehensive income ("OCI") until the underlying hedged transactions settle.

Working Capital

Working capital is the amount by which current assets exceed current liabilities. On a consolidated basis at the end of any given month, accounts receivable and payable tied to commodity sales and purchases are relatively balanced with receivables from NGL customers offset by plant settlements payable to producers. The factors that typically cause overall variability in our reported total working capital are: (1) our cash position; (2) liquids inventory levels and valuation, which we closely manage; (3) changes in the fair value of the current portion of derivative contracts; and (4) major structural changes in our asset base or business operations, such as acquisitions or divestitures and certain organic growth projects.

For 2013, our working capital increased $88.0 million, primarily due to the international export project which requires higher levels of accounts receivable and inventory, partially offset by an increase in accounts payable related to third party propane purchases. Other changes included decreases in affiliate payables due to the timing of reimbursements between Targa and us, decreases in the cash balance, and decreases in current liabilities due to the reversal of the Badlands contingent liability, partially offset by increased gas plant producer settlement payables due to higher commodity prices and higher volumes. Our net risk management working capital position also decreased due to changes in the forward prices of commodities.

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

Cash Flow

The following table and discussion summarize our consolidated cash flows provided by or used in operating activities, investing activities and financing activities:

	2013	2012	2011	2013 vs. 2012	2012 vs. 2011
			(In millions)		
Net cash provided by (used in):					
Operating activities	$ 411.4	$ 465.4	$ 400.9	$ (54.0)	$ 64.5
Investing activities	(1,026.3)	(1,593.8)	(506.1)	567.5	(1,087.7)
Financing activities	604.4	1,140.8	84.5	(536.4)	1,056.3

Cash Flow from Operating Activities

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

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

	2013	2012	2011	2013 vs. 2012	2012 vs. 2011
			(In millions)		
Cash flows from operating activities:					
Cash received from customers	$ 6,388.3	$ 5,948.9	$ 6,916.0	$ 439.4	$ (967.1)
Cash received from (paid to) derivative counterparties	20.9	47.3	(56.6)	(26.4)	103.9
Cash outlays for:					
Product purchases	(5,364.8)	(4,972.9)	(5,960.1)	(391.9)	987.2
Operating expenses	(377.3)	(339.6)	(286.1)	(37.7)	(53.5)
General and administrative expenses	(145.3)	(117.8)	(124.1)	(27.5)	6.3
Cash distributions from equity investment (1)	12.0	1.8	8.3	10.2	(6.5)
Interest paid, net of amounts capitalized (2)	(119.1)	(92.5)	(92.7)	(26.6)	0.2
Income taxes paid	(2.3)	(2.2)	(2.5)	(0.1)	0.3
Other cash receipts (payments)	(1.0)	(7.6)	(1.3)	6.6	(6.3)
Net cash provided by operating activities	$ 411.4	$ 465.4	$ 400.9	$ (54.0)	$ 64.5

(1) Excludes $0.5 million included in investing activities for 2012 related to distributions from GCF that exceeded cumulative equity earnings. We did not have distributions that exceeded cumulative equity earnings for 2013 and 2011

(2) Net of capitalized interest paid of $28.0 million, $13.6 million and $3.4 million included in investing activities for 2013, 2012 and 2011.

Higher natural gas prices, higher plant throughput volumes and increased export activities contributed to increased cash collections in 2013 compared to 2012, as well as higher cash payments to producers and for commodity products. The change in cash received related to derivatives reflects higher aggregate commodity prices paid to counterparties compared to the aggregate fixed price we received on those derivative contracts. The decrease in other cash payments during 2013 was mainly attributable to the fees related to the Badlands acquisition paid in 2012.

Lower aggregate commodity prices were the primary factor in the changes in cash from customers, cash from derivative contracts, and cash paid for purchases in 2012 compared to 2011. In 2012, our derivative settlements were a net cash inflow, as opposed to a net outflow for 2011. The change in cash received from derivative counterparties reflects lower commodity prices compared to the higher fixed price we received on those derivative contracts. The increase in cash payments in other cash receipts (payments) during 2012 was mainly attributable to the fees related to the Badlands acquisition.

Cash Flow from Investing Activities

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), 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.

The increase in net cash used in investing activities for 2012 compared to 2011 was primarily due to an increase in outlays for business acquisitions of $839.7 million and current capital expansion projects of $289.0 million, partially offset by lower maintenance capital expenditures of $5.8 million.

Cash Flow from Financing Activities

The decrease in net cash provided by financing activities for 2013 compared to 2012 was primarily due to a reduction in net borrowing under the TRP Revolver ($347.0 million), lower long-term 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 of $279.7 million.

The increase in net cash provided by financing activities for 2012 compared to 2011 was primarily due to increased long-term debt borrowings of $874.3 million and proceeds from our issuance of common units of $250.4 million, partially offset by an increase in distributions to owners of $47.1 million.

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Our primary financing activities during the periods are summarized in the following tables.

2013	Financing Activity	Source (Use) (In millions)	Use of proceeds
May	Issuance of the 4¼% Notes in May 2013	$ 618.1	Redeem borrowings under 11¼% Notes; reduce outstanding borrowings under TRP Revolver and for general Partnership purposes
June	Redemption of $100.0 million face - 6⅜% Notes	(106.4)	
July	Redemption of $72.7 million face - 11¼% Note	(76.8)	
Various	Net repayments under TRP Revolver	(225.0)	
Various	Sale of common units - 2012 and 2013 EDAs	517.9	Redeem borrowings under 6⅜% Notes, reduce outstanding borrowings under TRP Revolver and general Partnership purposes
Various	General partner contributions to maintain 2% interest	10.8	Reduce outstanding borrowings under the TRP Revolver and for general Partnership purposes
Various	Net borrowings under the Securitization Facility	279.7	

2012	Financing Activity	Source (Use) (In millions)	Use of proceeds
January	Sale of common units in a public offering	$ 164.9	Reduce outstanding borrowings under the TRP Revolver and for general Partnership purposes
January	Issuance of the 6⅜% Notes	400.0	
October	Issuance of the 5¼% Senior Notes due 2023	400.0	Redeem remaining 8¼% Senior Notes and reduce borrowings under the TRP Revolver
November/ December	Sale of common units in a public offering	378.6	Partially fund the Badlands acquisition
December	Issuance of additional 5¼% Senior Notes due 2023	200.0	Partially fund the Badlands acquisition
Various	Net borrowings under TRP Revolver	122.0	Reduce outstanding borrowings under the TRP Revolver and for general Partnership purposes
Various	General partner contributions to maintain 2% interest	11.4	

2011	Financing Activity	Source (Use) (In millions)	Use of proceeds
January/ February	Sale of common units in a public offering	$ 298.0	Reduce outstanding borrowings under the TRP Revolver and for general Partnership purposes
February	Issuance of 6⅞% Notes	318.8	
February	Exchanged $158.6 million principal amount of our 6⅞% Notes for $158.6 million principal amount of our 11¼% Notes	158.6	Reduce outstanding borrowings under the 11¼% Notes
Various	General partner contributions to maintain 2% interest	6.3	Reduce outstanding borrowings under the TRP Revolver and for general Partnership purposes

Distributions to our Unitholders

We distribute all available cash from our operating surplus. As a result, we expect that we will rely upon external financing sources, including debt and common unit issuances, to fund our acquisition and expansion capital expenditures. See Notes 10 and 11 of the “Consolidated Financial Statements” included in this Annual Report.

We intend to make cash distributions to our unitholders and our general partner at least at the minimum quarterly distribution rate of $0.3375 per common unit per quarter ($1.35 per common unit on an annualized basis). As of December 31, 2013, such annual minimum amount would have been approximately $153.3 million. In every quarter since the fourth quarter of 2007, we have paid quarterly distributions greater than the minimum quarterly distribution rate. The quarterly distribution per limited partner unit to be paid in February 2014 for the fourth quarter of 2013 is $0.7475 per limited partner unit.

The following table details the distributions declared and/or paid during 2013, 2012 and 2011:

		Distributions				Distributions per Limited Partner Unit
		Limited Partners	General Partner			
Three Months Ended	Date Paid or to be Paid	Common	Incentive	2%	Total	
		(In millions, except per unit amounts)				
2013						
December 31, 2013	February 14, 2014	$ 84.0	$ 29.5	$ 2.3	$ 115.8	$ 0.7475
September 30, 2013	November 14, 2013	79.4	26.9	2.2	108.5	0.7325
June 30, 2013	August 14, 2013	75.8	24.6	2.0	102.4	0.7150
March 31, 2013	May 15, 2013	71.7	22.1	1.9	95.7	0.6975
2012						
December 31, 2012	February 14, 2013	$ 69.0	$ 20.1	$ 1.8	$ 90.9	$ 0.6800
September 30, 2012	November 14, 2012	59.1	16.1	1.5	76.7	0.6625
June 30, 2012	August 14, 2012	57.3	14.4	1.5	73.2	0.6425
March 31, 2012	May 15, 2012	55.5	12.7	1.4	69.6	0.6225
2011						
December 31, 2011	February 14, 2012	$ 53.7	$ 11.0	$ 1.3	$ 66.0	$ 0.6025
September 30, 2011	November 14, 2011	49.4	8.8	1.2	59.4	0.5825
June 30, 2011	August 12, 2011	48.3	7.8	1.2	57.3	0.5700
March 31, 2011	May 13, 2011	47.3	6.8	1.1	55.2	0.5575

Capital Requirements

Our 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 our existing assets, including the replacement of system components and equipment, which are worn, obsolete or completing their useful life and expenditures to remain in compliance with environmental laws and regulations.

	2013	2012	2011
Capital expenditures :		(In millions)	
Business acquisitions, net of cash acquired	$ -	$ 996.2	$ 156.5
Expansion (1)	954.6	540.7	251.7
Maintenance	79.9	76.0	81.8
Gross additions	1,034.5	1,612.9	490.0
Transfers from materials and supplies to property, plant and equipment	(20.5)	-	-
Change in capital project payables and accruals	(0.4)	(34.4)	(4.8)
Cash outlays for capital projects	$ 1,013.6	$ 1,578.5	$ 485.2

(1) Excludes our investment in GCF of \$16.8 million and \$21.2 million for 2012 and 2011, which is accounted for as an equity investment. We did not have additional investment in GCF for 2013. Cash calls for expansion 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.”

We estimate that our total growth capital expenditures for 2014 will be approximately \$650 million on a gross basis, and maintenance capital expenditures net to our interest will be approximately \$90 million. Given our objective of growth through acquisitions, expansions of existing assets and other internal growth projects, we anticipate that over time we will invest significant amounts of capital to grow and acquire assets. Future expansion capital expenditures may vary significantly based on investment opportunities. We expect to fund future capital expenditures with funds generated from our operations, borrowings under the TRP Revolver and the Securitization Facility and proceeds from issuances of additional equity and debt offerings. Major organic growth projects for 2014 include:

- *International Exports.* We have commenced construction of Phase II of our international export expansion project at our Mont Belvieu facility and the Galena Park Marine Terminal. Phase II will further expand our propane and butane international export capacity by approximately 2 MMBbl per month, with an expected completion during the third quarter of 2014. We expect that the total cost of both phases of our international export project to be approximately \$480 million.

- *Badlands expansion program.* During 2014, we anticipate that we will invest another $180 million for further expansion of our gathering and processing assets in North Dakota.

- *North Texas Longhorn plant.* We have started construction of a new 200 MMcf/d cryogenic processing plant for North Texas to meet increasing production and continued producer activity, with an anticipated completion in mid-2014. We expect to invest an estimated $180 million for the plant and associated projects.

- *SAOU High Plains plant.* We have started construction of a new 200 MMcf/d cryogenic processing plant and related gathering and compression facilities for SAOU to meet increasing production and continued producer activity on the eastern side of the Permian Basin, with an anticipated completion date in mid-2014. We expect to invest an estimated $225 million for the plant and associated projects.

Additionally, we expect to have other growth capital expenditures in 2014 related to the continued build out of our gathering and processing systems and logistics capabilities.

Credit Facilities and Long-Term Debt

The following table summarizes our debt obligation as of December 31, 2013 (in millions):

Partnership Obligations		
Senior secured revolving credit facility, due October 2017	$	395.0
Senior unsecured notes, 7⅞% fixed rate, due July 2018		250.0
Senior unsecured notes, 6⅞% fixed rate, due July 2021		483.6
Unamortized discount		(28.0)
Senior unsecured notes, 6⅜% 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
Accounts receivable Securitization Facility, due January 2014		279.7
Total long-term debt	$	2,905.3

Compliance with Debt Covenants

As of December 31, 2013, we were in compliance with the covenants contained in our various debt agreements.

Revolving Credit Agreement

In October 2012, we entered into a Second Amended and Restated Credit Agreement that amends and replaces our existing variable rate Senior Secured Credit Facility due July 2015 (the “Previous Revolver”) to provide for the TRP Revolver due October 3, 2017. The TRP Revolver increased available commitments to $1.2 billion from $1.1 billion and allows us to request up to an additional $300.0 million in commitment increases.

For 2013, we had gross borrowings under our TRP Revolver of $1,613.0 million, and repayments totaling $1,838.0 million, for a net decrease for the year ended December 31, 2013 of $225.0 million. The TRP Revolver balance at December 31, 2013 was $395.0 million.

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

We are required to pay a commitment fee equal to an applicable rate ranging from 0.3% to 0.5% 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%.

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

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

Senior Unsecured Notes

In February 2011, we exchanged $158.6 million principal amount of our 6⅞% Senior Notes due 2021 (the “6⅞% Notes”) plus payments of $28.6 million including $0.9 million of accrued interest for $158.6 million aggregate principal amount of our 11¼% Notes. The holders of the exchanged Notes are subject to the provisions of the 6⅞% Notes described below. The debt covenants related to the remaining $72.7 million of face value of the 11¼% Notes were removed. This exchange was accounted for as a debt modification whereby the financial effects of the exchange will be recognized over the term of the new debt issue.

In January 2012, we privately placed $400.0 million in aggregate principal amount of our 6⅜% Notes. The 6⅜% Notes resulted in approximately $395.5 million of net proceeds, which were used to reduce the borrowings under the TRP Revolver and for general partnership purposes.

In October 2012, $400.0 million in aggregate principal amount of our 5¼% Notes were issued 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 our 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.

In November 2012, we redeemed the outstanding 8¼% Notes at a redemption price of 104.125% plus accrued interest through the redemption date. The redemption resulted in an $11.1 million loss, including the write off of unamortized debt issue costs.

In May 2013, we privately placed $625.0 million in aggregate principal amount of the 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 redeemed $100 million of the outstanding 6⅜% Notes at a redemption price of 106.375% plus accrued interest through the redemption date. The redemption resulted in a $7.4 million loss, including the write-off of unamortized debt issue costs.

In July 2013, we redeemed the outstanding 11¼% Notes at a price of 105.625% plus accrued interest through the redemption date. The redemption resulted in a $7.4 million loss, including the write-off of unamortized debt issue costs.

The terms of our senior unsecured notes outstanding as of December 31, 2013 were as follows:

Note Issue	Issue Date	Per Annum Interest Rate	Due Date	Dates Interest Paid
"7⅞% Notes"	August 2010	7⅞%	October 15, 2018	April & October 15th
"6⅞% Notes"	February 2011	6⅞%	February 1, 2021	February & August 1st
"6⅜% Notes"	January 2012	6⅜%	August 1, 2022	February & August 1st
"5¼% Notes"	Oct / Dec 2012	5¼%	May 1, 2023	May & November 1st
"4¼% Notes"	May 2013	4¼%	November 15, 2023	May & November 15th

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

Our senior unsecured notes and associated indenture agreements restrict our ability to make distributions to unitholders in the event of default (as defined in the indentures). The indentures also restrict our ability and the ability of certain of our subsidiaries to: (i) incur additional debt or enter into sale and leaseback transactions; (ii) pay certain distributions on or repurchase equity interests (only if such distributions do not meet specified conditions); (iii) make certain investments; (iv) incur liens; (v) enter into transactions with affiliates; (vi) merge or consolidate with another company; and (vii) transfer and sell assets. These covenants are subject to a number of important exceptions and qualifications. If at any time when the notes are rated investment grade by both Moody’s Investors Service, Inc. and Standard & Poor’s Corporation and no Default or Event of Default (each as defined in the indentures) has occurred and is continuing, many of such covenants will terminate and we will cease to be subject to such covenants.

Accounts Receivable Securitization Facility

In January 2013, we entered into a Securitization Facility that provides up to $200 million of borrowing capacity at commercial paper or LIBOR market index rates plus a margin through January 2014. Under this Securitization Facility, one of our consolidated subsidiaries (TLMT) sells or contributes receivables, without recourse, to another of our consolidated subsidiaries (TRLLC), a special purpose consolidated subsidiary created for the sole purpose of this 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 or us. Any excess receivables are eligible to satisfy the claims of creditors of TLMT or us.

In December 2013, we entered into an amendment to our Securitization Facility to increase the borrowing capacity to $300 million and extend the termination date to December 12, 2014. As of December 31, 2013, total funding under this Securitization Facility was $279.7 million.

Off-Balance Sheet Arrangements

We currently have no off-balance sheet arrangements as defined by the SEC. See “Contractual Obligations” below and “Commitments and Contingencies” included under Note 16 of our “Consolidated Financial Statements” for a discussion of our commitments and contingencies.

Contractual Obligations

The following is a summary of certain contractual obligations over the next several years, including the disclosures related to debt and lease obligations, contained in Notes 10 and 16 of the "Consolidated Financial Statements" of this Annual Report.

	Payments Due By Period				
Contractual Obligations	**Total**	**Less Than 1 Year**	**1-3 Years**	**3-5 Years**	**More Than 5 Years**
	(In millions, except volumetric information)				
Debt obligations (1)	$ 2,933.3	$ 279.7	$ -	$ 645.0	$ 2,008.6
Interest on debt obligations (2)	937.3	106.3	227.0	252.0	352.0
Operating leases (3)	42.3	8.0	15.2	10.7	8.4
Pipeline capacity and throughput agreements (4), (8)	152.3	19.1	34.8	32.8	65.6
Land site lease and right-of-way (5)	7.9	1.7	3.2	3.0	-
Commodities (6), (8)	495.0	495.0	-	-	-
Purchase commitments (7), (8)	240.9	236.8	4.1	-	-
	$ 4,809.0	$ 1,146.6	$ 284.3	$ 943.5	$ 2,434.6
Commodity volumetric commitments:					
Natural Gas (MMBtu)	40.9	40.9	-	-	-
NGL and petroleum products (millions of gallons)	235.6	235.6	-	-	-

(1) Represents scheduled future maturities of consolidated debt obligations for the periods indicated.
(2) Represents interest expense on debt obligations based on both fixed debt interest rates and prevailing December 31, 2013 rates for floating debt.
(3) Includes minimum payments on lease obligations for office space, railcars and tractors.
(4) Consists of pipeline capacity payments for firm transportation and throughput and deficiency agreements.
(5) Land site lease and right-of-way provides for surface and underground access for gathering, processing and distribution assets that are located on property not owned by us. These agreements expire at various dates through 2099.
(6) Includes natural gas and NGL purchase commitments.
(7) Includes commitments for capital expenditures and operating expenses.
(8) A purchase obligation mean an agreement to purchase goods or services that is enforceable, legally binding and specifies all significant terms including: fixed, minimum or variable price provisions; and the approximate timing of the transaction.

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with GAAP requires our management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from these estimates. The policies and estimates discussed below are considered by management to be critical to an understanding of our financial statements because their application requires the most significant judgments from management in estimating matters for financial reporting that are inherently uncertain. See the description of our accounting policies in the notes to the financial statements for additional information about our critical accounting policies and estimates.

Property, Plant and Equipment and Intangibles

In general, depreciation and amortization is the systematic and rational allocation of an asset's cost, less its residual value (if any), to the period it benefits. Our property, plant and equipment are depreciated using the straight-line method over the estimated useful lives of the assets. Our estimate of depreciation incorporates assumptions regarding the useful economic lives and residual values of our assets. Amortization expense attributable to intangible assets is recorded in a manner that closely resembles the expected pattern in which we benefit from services provided to customers. At the time we place our assets in service, we believe such assumptions are reasonable; however, circumstances may develop that would cause us to change these assumptions, which would change our depreciation/amortization amounts prospectively. Examples of such circumstances include:

- changes in energy prices;
- changes in competition;

- changes in laws and regulations that limit the estimated economic life of an asset;
- changes in technology that render an asset obsolete;
- changes in expected salvage values; and
- changes in the forecast life of applicable resources basins.

We evaluate long-lived assets, including related intangibles, of identifiable business activities for impairment when events or changes in circumstances indicate, in management's judgment, that the carrying value of such assets may not be recoverable. There have been no material changes impacting long-lived assets.

Revenue Recognition

Our operating revenues are primarily derived from the following activities:

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

We recognize revenues when all of the following criteria are met: (1) persuasive evidence of an exchange arrangement exists, if applicable; (2) delivery has occurred or services have been rendered; (3) the price is fixed or determinable and (4) collectability is reasonably assured.

Price Risk Management (Hedging)

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

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

One of the primary factors that can affect our operating results each period is the price assumptions used to value our derivative financial instruments, which are reflected at their fair values in the balance sheet. The relationship between the derivative financial instruments and the hedged item must be highly effective in achieving the offset of changes in cash flows attributable to the hedged risk both at the inception of the derivative financial instrument and on an ongoing basis. Hedge accounting is discontinued prospectively when a derivative financial instrument becomes ineffective. Gains and losses deferred in other comprehensive income related to cash flow hedges for which hedge accounting has been discontinued remain deferred until the forecasted transaction occurs. If it is probable that a hedged forecasted transaction will not occur, deferred gains or losses on the derivative financial instrument are reclassified to earnings immediately.

The estimated fair value of our derivative financial instruments was a net liability of $4.3 million as of December 31, 2013, net of an adjustment for credit risk. The credit risk adjustment is based on the default probabilities by year as indicated by the counterparties' credit default swap transactions. These default probabilities have been applied to the unadjusted fair values of the derivative financial instruments to arrive at the credit risk adjustment, which is immaterial for all periods covered by this Annual Report. We have an active credit management process which is focused on controlling loss exposure to bankruptcies or other liquidity issues of counterparties. If a financial instrument counterparty were to declare bankruptcy, we would be exposed to the loss of fair value of the financial instrument transaction with that counterparty, less any liability from our master netting arrangements. Ignoring our adjustment for credit risk, if a bankruptcy by a financial instrument counterparty impacted 10% of the fair value of our commodity-based financial instruments that are in an asset position, we estimate that our operating income would decrease by $0.3 million in the year of the bankruptcy.

Use of Estimates

When preparing financial statements in conformity with GAAP, management must make estimates and assumptions based on information available at the time. These estimates and assumptions affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosures of contingent assets and liabilities as of the date of the financial statements. Estimates and judgments are based on information available at the time such estimates and judgments are made. Adjustments made with respect to the use of these estimates and judgments often relate to information not previously available. Uncertainties with respect to such estimates and judgments are inherent in the preparation of financial statements. Estimates and judgments are used in, among other things, (1) estimating unbilled revenues, product purchases and operating and general and administrative costs, (2) developing fair value assumptions, including estimates of future cash flows and discount rates, (3) analyzing long-lived assets for possible impairment, (4) estimating the useful lives of assets and (5) determining amounts to accrue for contingencies, guarantees and indemnifications. Actual results, therefore, could differ materially from estimated amounts.

Recent Accounting Pronouncements

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

Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

Our principal market risks are our exposure to changes in commodity prices, particularly to the prices of natural gas, NGLs and crude oil, changes in interest rates, as well as nonperformance by our customers. We do not use risk-sensitive instruments for trading purposes.

Commodity Price Risk

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

The primary purpose of our commodity risk management activities is to hedge some of the exposure to commodity price risk and reduce volatility in our operating cash flow due to fluctuations in commodity prices. In an effort to reduce the variability of our cash flows, as of December 31, 2013, we have hedged the commodity prices associated with a portion of our expected (i) natural gas equity volumes in Field Gathering and Processing Operations and (ii) NGL and condensate equity volumes predominately in Field Gathering and Processing Operations as well as in the LOU portion of the Coastal Gathering and Processing Operations, that results from percent-of-proceeds processing arrangements by entering into derivative instruments. We hedge a higher percentage of our expected equity volumes in the current year compared to future years, in which we hedge incrementally lower percentages of expected equity volumes. With swaps, we typically receive an agreed fixed price for a specified notional quantity of natural gas or NGLs and we pay the hedge counterparty a floating price for that same quantity based upon published index prices. Since we receive from our customers substantially the same floating index price from the sale of the underlying physical commodity, these transactions are designed to effectively lock-in the agreed fixed price in advance for the volumes hedged. In order to avoid having a greater volume hedged than our actual equity volumes, we typically limit our use of swaps to hedge the prices of less than our expected natural gas and NGL equity volumes. We utilize purchased puts (or floors) and calls (or caps) to hedge additional expected equity commodity volumes without creating volumetric risk. We may buy calls in connection with swap positions to create a price floor with upside. We intend to continue to manage our exposure to commodity prices in the future by entering into derivative transactions using swaps, collars, purchased puts (or floors) or other derivative instruments as market conditions permit.

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

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

For all periods presented, we have entered into hedging arrangements for a portion of our forecasted equity volumes. During the year ended December 31, 2013, 2012 and 2011, our operating revenues increased (decreased) by net hedge adjustments on commodity derivative contracts of $21.4 million, $41.1 million and ($37.6) million.

As of December 31, 2013, we had the following derivative instruments, which are designated as hedging instruments, that will settle during the years ending below:

Natural Gas

Instrument Type	Index	Price $/MMBtu	MMBtu/d 2014	MMBtu/d 2015	MMBtu/d 2016	Fair Value
						(In millions)
Swap	IF-WAHA	3.88	29,780			$ (1.9)
Swap	IF-WAHA	3.97		18,736		(0.1)
Swap	IF-WAHA	4.02			14,436	0.3
Total Swaps			29,780	18,736	14,436	
Swap	IF-PB	3.80	11,966			(0.9)
Swap	IF-PB	4.02		11,076		0.2
Swap	IF-PB	4.22			7,608	0.6
Total Swaps			11,966	11,076	7,608	
Swap	IF-NGPL MC	3.58	6,304			(0.9)
Swap	IF-NGPL MC	3.84		4,739		0.1
Swap	IF-NGPL MC	3.93			3,456	0.4
Total Swaps			6,304	4,739	3,456	
Total			48,050	34,551	25,500	
						$ (2.2)

NGL

Instrument Type	Index	Price $/Gal	Bbl/d 2014	Fair Value
				(In millions)
Swap	OPIS-MB	1.31	1,125	$ 1.5
Total			1,125	
				$ 1.5

Condensate

Instrument Type	Index	Price $/Bbl	Bbl/d 2014	Fair Value
				(In millions)
Swap	NY-WTI	91.86	2,450	$ (3.3)
Total			2,450	
				$ (3.3)

These contracts may expose us to the risk of financial loss in certain circumstances. Generally, our hedging arrangements provide us protection on the hedged volumes if prices decline below the prices at which these hedges are set. If prices rise above the prices at which we have hedged, we will receive less revenue on the hedged volumes than we would receive in the absence of hedges (other than with respect to purchased calls).

We account for the fair value of our financial assets and liabilities using a three-tier fair value hierarchy, which prioritizes the significant inputs used in measuring fair value. These tiers include: Level 1, defined as observable inputs such as quoted prices in active markets; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs in which little or no market data exists, therefore requiring an entity to develop its own assumptions. We determine the value of our derivative contracts utilizing a discounted cash flow model for swaps and a standard option-pricing model for options based on inputs that are readily available in public markets. For the contracts that have inputs from quoted prices, the classification of these instruments is Level 2 within the fair value hierarchy. For those contracts which we are unable to obtain quoted prices for at least 90% of the full term of the commodity swap and options, the valuations are classified as Level 3 within the fair value hierarchy. See Note 14 to the "Consolidated Financial Statements" in this Annual Report for more information regarding classifications within the fair value hierarchy.

Interest Rate Risk

We are exposed to the risk of changes in interest rates, primarily as a result of variable rate borrowings under the TRP Revolver and the Securitization Facility. As of December 31, 2013, we do not have any interest rate hedges. However, we may in the future enter into interest rate hedges intended to mitigate the impact of changes in interest rates on cash flows. To the extent that interest rates increase, interest expense for the TRP Revolver and the Securitization Facility will also increase. As of December 31, 2013, we had $674.7 million in variable rate borrowings under the TRP Revolver and the Securitization Facility. A hypothetical change of 100 basis points in the interest rate of our variable rate debt would impact our annual interest expense before any amounts capitalized by $6.7 million.

Counterparty Credit Risk

We are subject to risk of losses resulting from nonpayment or nonperformance by our counterparties. The credit exposure related to commodity derivative instruments is represented by the fair value of the asset position (i.e. the fair value of expected future receipts) at the reporting date. Should the creditworthiness of one or more of the counterparties decline, our ability to mitigate nonperformance risk is limited to a counterparty agreeing to either a voluntary termination and subsequent cash settlement or a novation of the derivative contract to a third party. In the event of a counterparty default, we may sustain a loss and our cash receipts could be negatively impacted.

As of December 31, 2013 affiliates of Bank of America Merrill Lynch (“BAML”), Natixis Securities Americas LLC (“Natixis”) and Barclays PLC (“Barclays”) accounted for 37%, 26% and 24% of our counterparty credit exposure related to commodity derivative instruments. BAML, Natixis and Barclays are major financial institutions that possess investment grade credit ratings based upon minimum credit ratings assigned by Moody’s Investors Service, Inc. and Standard & Poor’s Corporation.

Customer Credit Risk

We extend credit to customers and other parties in the normal course of business. We have established various procedures to manage our credit exposure, including initial credit approvals, credit limits and terms, letters of credit and rights of offset. We also use prepayments and guarantees to limit credit risk to ensure that our established credit criteria are met.

We have an active credit management process, which is focused on controlling loss exposure to bankruptcies or other liquidity issues of counterparties. If an assessment of uncollectible accounts resulted in a 1% reduction of our third-party accounts receivable, annual operating income would decrease by $6.6 million in the year of the assessment.

Item 8. Financial Statements and Supplementary Data.

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

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

None.

Item 9A. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

Management, under the supervision of and with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the design and effectiveness of our disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act") as of the end of the period covered in this Annual Report. Based on such evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of December 31, 2013, our disclosure controls and procedures were designed at the reasonable assurance level and, as of the end of the period covered in this Annual Report, our disclosure controls and procedures are effective at the reasonable assurance level to provide that information required to be disclosed in our reports filed or submitted under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC and (ii) accumulated and communicated to management, including our principal executive officer and principal financial officer, as appropriate, to allow for timely decisions regarding required disclosure.

Internal Control Over Financial Reporting

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

Management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Management, including the Chief Executive Officer and Chief Financial Officer, conducted an evaluation of the effectiveness of the internal control over financial reporting based on the report entitled "Internal Control — Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission in 1992. Based on the results of this evaluation, management concluded that the internal control over financial reporting was effective as of December 31, 2013, as stated in its report included in our "Consolidated Financial Statements" on page F-2 of this Annual Report, which is incorporated herein by reference.

(b) Changes in Internal Control Over Financial Reporting

During the three months ended December 31, 2013, there were no changes in our internal control over financial reporting that have materially affected or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information.

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

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

Management of Targa Resources Partners LP

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

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

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

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

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

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

Directors, Executive Officers and Other Officers

Our general partner's directors hold office until the earlier of their death, resignation, removal or disqualification or until their successors have been elected and qualified. Officers serve at the discretion of the Board. There are not family relationships among any of our general partner's directors or executive officers. The following table shows information regarding the current directors, executive officers and certain significant employees of Targa Resources GP LLC as of February 10, 2014:

Name	Age	Position With Targa Resources GP LLC
Rene R. Joyce	66	Executive Chairman of the Board and Director
Joe Bob Perkins	53	Chief Executive Officer and Director
James W. Whalen	72	Advisor to Chairman and CEO and Director
Michael A. Heim	65	President and Chief Operating Officer
Jeffrey J. McParland	59	President-Finance and Administration
Roy E. Johnson	69	Executive Vice President
Paul W. Chung	53	Executive Vice President, General Counsel and Secretary
Matthew J. Meloy	36	Senior Vice President, Chief Financial Officer and Treasurer
John R. Sparger	60	Senior Vice President and Chief Accounting Officer
In Seon Hwang	37	Director
Robert B. Evans	65	Director
Barry R. Pearl	64	Director
William D. Sullivan	57	Director
Ruth I. Dreessen	57	Director

Rene R. Joyce has served as Executive Chairman of the Board of our general partner, Targa and TRI since January 1, 2012 and as a director of Targa since its formation on October 27, 2005 and of our general partner since October 2006. Mr. Joyce previously served as Chief Executive Officer of Targa between October 27, 2005 and December 31, 2011, our general partner between October 2006 and December 31, 2011 and TRI between February 2004 and December 31, 2011. He also served as director of TRI between 2004 and December 31, 2011 and was a consultant for the TRI predecessor company during 2003. He is also a member of the supervisory directors of Core Laboratories N.V. Mr. Joyce served as a consultant in the energy industry from 2000 through 2003 providing advice to various energy companies and investors regarding their operations, acquisitions and dispositions. Mr. Joyce served as President of onshore pipeline operations of Coral Energy, LLC, a subsidiary of Shell Oil Company ("Shell") from 1998 through 1999 and President of energy services of Coral Energy Holding, L.P. ("Coral"), a subsidiary of Shell which was the gas and power marketing joint venture between Shell and Tejas Gas Corporation ("Tejas"), during 1999. Mr. Joyce served as President of various operating subsidiaries of Tejas, a natural gas pipeline company, from 1990 until 1998 when Tejas was acquired by Shell. As the founding Chief Executive Officer of TRI, Mr. Joyce brings deep experience in the midstream business, expansive knowledge of the oil and gas industry, as well as relationships with chief executives and other senior management at peer companies, customers and other oil and natural gas companies throughout the world. His experience and industry knowledge, complemented by an engineering and legal educational background, enable Mr. Joyce to provide the board with executive counsel on the full range of business, technical, and professional matters.

Joe Bob Perkins has served as Chief Executive Officer and director of our general partner, Targa and TRI since January 1, 2012. Mr. Perkins previously served as President of Targa between the date of its formation on October 27, 2005 and December 31, 2011, of our general partner between October 2006 and December 31, 2011 and of TRI between February 2004 and December 31, 2011. He was a consultant for the TRI predecessor company during 2003. Mr. Perkins was an independent consultant in the energy industry from 2002 through 2003 and was an active partner in an outdoor advertising firm during a portion of such time period. Mr. Perkins served as President and Chief Operating Officer for the Wholesale Businesses, Wholesale Group and Power Generation Group of Reliant Resources, Inc. and its parent/predecessor companies, from 1998 to 2002 and Vice President, Corporate Planning and Development, of Houston Industries from 1996 to 1998. He served as Vice President, Business Development, of Coral from 1995 to 1996 and as Director, Business Development, of Tejas from 1994 to 1995. Prior to 1994, Mr. Perkins held various positions with the consulting firm of McKinsey & Company and with an exploration and production company. Mr. Perkins' intimate knowledge of all facets of Targa, derived from his service as President from its founding through 2011 and his current service as Chief Executive Officer and director, coupled with his broad experience in the oil and gas industry, and specifically in the midstream sector, his engineering and business educational background and his experience with the investment community enable Mr. Perkins to provide a valuable and unique perspective to the board on a range of business and management matters.

James W. Whalen has served as Advisor to Chairman and CEO of our general partner, Targa and TRI since January 1, 2012 and as a director of Targa since its formation on October 27, 2005, of our general partner since February 2007 and of TRI between 2004 and December 2010. Mr. Whalen previously served as Executive Chairman of the Board of Targa and TRI between October 25, 2010 and December 31, 2011 and of our general partner between December 15, 2010 and December 31, 2011. He also served as President-Finance and Administration of Targa and TRI between January 2006 and October 2010 and our general partner between October 2006 and December 2010 and for various Targa subsidiaries since November 2005. Between October 2002 and October 2005, Mr. Whalen served as the Senior Vice President and Chief Financial Officer of Parker Drilling Company. Between January 2002 and October 2002, he was the Chief Financial Officer of Diversified Diagnostic Products, Inc. He served as Chief Commercial Officer of Coral from February 1998 through January 2000. Previously, he served as Chief Financial Officer for Tejas from 1992 to 1998. Mr. Whalen brings a breadth and depth of experience as an executive, board member, and audit committee member across several different companies and in energy and other industry areas. His valuable management and financial expertise includes an understanding of the accounting and financial matters that the Partnership and industry address on a regular basis.

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

Jeffrey J. McParland has served as President — Finance and Administration of our general partner since December 15, 2010 and of Targa and TRI since October 25, 2010. He has also served as a director of TRI since December 16, 2010. Mr. McParland served as Executive Vice President and Chief Financial Officer of Targa between October 27, 2005 and October 25, 2010 and of TRI between April 2004 and October 25, 2010 and was a consultant for the TRI predecessor company during 2003. He served as Executive Vice President and Chief Financial Officer of our general partner between October 2006 and December 15, 2010 and served as a director of our general partner from October 2006 to February 2007. Mr. McParland served as Treasurer of Targa from October 27, 2005 until May 2007, of our general partner from October 2006 until May 2007 and of TRI from April 2004 until May 2007. Mr. McParland served as Secretary of TRI between February 2004 and May 2004, at which time he was elected as Assistant Secretary. Mr. McParland served as Senior Vice President, Finance of Dynegy Inc., a company engaged in power generation, the midstream natural gas business and energy marketing, from 2000 to 2002. In this position, he was responsible for corporate finance and treasury operations activities. He served as Senior Vice President, Chief Financial Officer and Treasurer of PG&E Gas Transmission, a midstream natural gas and regulated natural gas pipeline company, from 1999 to 2000. Prior to 1999, he worked in various engineering and finance positions with companies in the power generation and engineering and construction industries.

Roy E. Johnson has served as Executive Vice President of our general partner since October 2006, Targa since its formation on October 27, 2005, and of TRI since April 2004 and was a consultant for the TRI predecessor company during 2003. Mr. Johnson also served as a consultant in the energy industry from 2000 through 2003 providing advice to various energy companies and investors regarding their operations, acquisitions and dispositions. He served as Vice President, Business Development and President of the International Group of Tejas from 1995 to 2000. In these positions, he was responsible for acquisitions, pipeline expansion and development projects in North and South America. Mr. Johnson served as President of Louisiana Resources Company, a company engaged in intrastate natural gas transmission, from 1992 to 1995. Prior to 1992, Mr. Johnson held various positions with a number of different companies in the upstream and downstream energy industry.

Paul W. Chung has served as Executive Vice President, General Counsel and Secretary of our general partner since October 2006, Targa since its formation on October 27, 2005, and of TRI since May 2004. Mr. Chung served as Executive Vice President and General Counsel of Coral from 1999 to April 2004; Shell Trading North America Company, a subsidiary of Shell, from 2001 to April 2004; and Coral Energy, LLC from 1999 to 2001. In these positions, he was responsible for all legal and regulatory affairs. He served as Vice President and Assistant General Counsel of Tejas from 1996 to 1999. Prior to 1996, Mr. Chung held a number of legal positions with different companies, including the law firm of Vinson & Elkins L.L.P.

Matthew J. Meloy has served as Senior Vice President, Chief Financial Officer and Treasurer of our general partner since December 15, 2010 and of Targa and TRI since October 25, 2010. Mr. Meloy served as Vice President — Finance and Treasurer of Targa and TRI between April 2008 and October 2010, and as Director, Corporate Development of Targa and TRI between March 2006 and March 2008 and of our general partner between March 2006 and March 2008. He has served as Vice President — Finance and Treasurer of our general partner between April 2008 and December 15, 2010. Mr. Meloy was with The Royal Bank of Scotland in the structured finance group, focusing on the energy sector from October 2003 to March 2006, most recently serving as Assistant Vice President.

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

In Seon Hwang has served as a director of our general partner since February 2011, of Targa between May 2006 and February 2013 and of TRI between May 2006 and December 2010. Mr. Hwang is a Member and Managing Director of Warburg Pincus LLC and a general partner of Warburg Pincus & Co., where he has been employed since 2004, and became a partner of Warburg Pincus & Co. in 2009. Prior to joining Warburg Pincus, Mr. Hwang worked at GSC Partners, a distressed investment firm, from 2002 until 2004, the M&A group at Goldman Sachs from 1998 to 2000, and the Boston Consulting Group from 1997 to 1998. He is also a director of CASA Exploration, Competitive Power Ventures, Gulf Coast Energy Resources, LLC, Omega Energia Renovavel S.A. and Venari Resources LLC and serves on the investment committee of Sheridan Production Partners LLC. Mr. Hwang has significant experience with energy companies and investments and broad familiarity with the industry and related transactions and capital markets activity, which enhance his contributions to the board of directors.

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

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

William D. Sullivan has served as a director of our general partner since February 2007. Mr. Sullivan is a director of SM Energy Company, where he serves as a non-executive Chairman of the Board. Mr. Sullivan is also a director of Legacy Reserves GP, LLC, Tetra Technologies, Inc. and Compressco Partners GP, LLC. Between 1981 and August 2003, Mr. Sullivan was employed in various capacities by Anadarko Petroleum Corporation, including serving as Executive Vice President, Exploration and Production between August 2001 and August 2003. Since Mr. Sullivan's departure from Anadarko Petroleum Corporation in August 2003, he has served on various private energy company boards. Mr. Sullivan's extensive experience in the exploration and production sector enhances the knowledge of our general partner's board of directors in this particular area of the oil and gas industry. As a former exploration and production operating officer with responsibilities over significant gas gathering, compression and processing operations, his experience is valuable to the board's understanding of one of our most important customer types and contributes to other matters routinely facing us.

Ruth I. Dreessen has served as a director of our general partner since February 6, 2013. Ms. Dreessen is a Managing Director of Huntsman-Lion Capital, LLC (and its predecessor, Lion Chemical Capital, LLC) where she has been employed since October 2010. Ms. Dreessen is also a director of Gevo, Inc. and Versar, Inc. Ms Dreessen served as the Executive Vice President and Chief Financial Officer of TPC Group, Inc. from November 2005 to May 2010. Before joining TPC Group, she served as Senior Vice President, Chief Financial Officer and Director of Westlake Chemical Corp. from 2003 to 2005. Ms. Dreessen spent 21 years at JP Morgan Securities and predecessor companies ultimately as a Managing Director of chemicals investment banking, focused on leveraged and private equity transactions in chemicals and related industries. Ms. Dreessen's successful track record in investment banking with a focus in the chemical industry enhances the knowledge of the board in these areas. Her extensive experience as a financial executive brings financial and capital markets experience to the board.

Reimbursement of Expenses of Our General Partner

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

Corporate Governance

Code of Business Conduct and Ethics

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

Available Information

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

Corporate Governance Guidelines

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

Executive Sessions of Non-Management Directors

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

Interested parties may communicate directly with our non-management directors by writing to: Non-Management Directors, Targa Resources Partners LP, 1000 Louisiana, Suite 4300, Houston, Texas 77002.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Securities Exchange Act of 1934 requires our directors, executive officers and 10% unitholders to file with the SEC reports of ownership and changes in ownership of our equity securities. Based solely upon a review of the copies of the Form 3, 4 and 5 reports furnished to us and certifications from our directors and executive officers, we believe that during 2013, all of our directors, executive officers and beneficial owners of more than 10% of our common units complied with Section 16(a) filing requirements applicable to them.

Item 11.Executive Compensation.

Compensation Discussion and Analysis

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

Overview

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

For 2013, our general partner's "named executive officers," identified in the Summary Compensation Table, were:

- Rene R. Joyce – Executive Chairman of the Board;
- Joe Bob Perkins – Chief Executive Officer;
- James W. Whalen – Advisor to Chairman and CEO;
- Michael A. Heim – President and Chief Operating Officer; and
- Matthew J. Meloy – Senior Vice President, Chief Financial Officer and Treasurer.

Our general partner's named executive officers also serve as executive officers of Targa, which is the parent of our general partner. The compensation information described in this CD&A and contained in the tables that follow reflects all compensation received by our general partner's named executive officers for the services they provide to us and for the services they provide to Targa and our general partner for the years covered.

All decisions regarding this compensation are made by the compensation committee of Targa's board of directors (the "Compensation Committee"), except that long-term equity incentive awards recommended by the Compensation Committee under the Targa Resources Partners Long-Term Incentive Plan are approved by the board of directors of our general partner who oversees that plan. The named executive officers devote their time as needed to the conduct of our business and affairs and the conduct of Targa and our general partner's business and affairs. During 2013, we reimbursed Targa and its affiliates for the compensation of our general partner's named executive officers pursuant to the Partnership Agreement and, until its expiration in April 2013, the terms, and subject to the limitations, of the Omnibus Agreement. See "Certain Relationships and Related Transactions, and Director Independence—Partnership Agreement" for additional information regarding our reimbursement obligations for 2013.

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

Targa held its first advisory say on pay vote regarding executive compensation at its 2011 Annual Meeting. At that meeting, more than 99% of the votes cast by Targa's shareholders approved the compensation paid to its named executive officers as described in the CD&A and the other related compensation tables and disclosures contained in its Proxy Statement filed with the SEC on April 4, 2011. Targa's board of directors and the Compensation Committee reviewed the results of this vote and concluded that with this level of support, no changes to the compensation design and philosophy needed to be considered as a result of the vote. In accordance with the preference expressed by Targa's shareholders to conduct an advisory vote on executive compensation every three years, the next advisory vote will occur as part of Targa's 2014 Annual Meeting. We are generally not subject to the advisory say on pay vote requirements under the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010.

The following CD&A is presented from the perspective of the Compensation Committee and discusses our general partner's named executive officers in their roles as officers of Targa. The elements of compensation and the Compensation Committee's decisions with respect to determination on payments are not subject to approval by the board of directors of our general partner or the board of directors of Targa (the "Targa Board"). Certain members of the board of directors of our general partner are members of the Targa Board. Messrs. Pearl, Evans, Hwang and Sullivan and Ms. Dreessen, each a director of our general partner, were observers at Compensation Committee meetings in 2013. As used in this CD&A (other than in this "Overview"), references to "our," "we," "us," the "Company," and similar terms refer to Targa, references to the "Board" or "Board of Directors" refers to the Targa Board, and references to the Partnership refer to us, Targa Resources Partners LP.

Summary of Key Strategic Results

Our main source of cash flow is from our general and limited partner interests and our incentive distribution rights in the Partnership. As described in "Management's Discussion and Analysis of Financial Conditions and Results of Operations" in our Annual Report on Form 10-K, our 2013 strategic and operational accomplishments, our 2013 financial results and the 2013 financial results of the Partnership demonstrate the significant increases in both our business scale and diversity and in our results of operations in comparison to 2012. In summary, some of our and the Partnership's more significant financial, operational and strategic highlights in 2013 included:

- On balance, excellent execution across our businesses, including strong financial performance, with the Partnership's EBITDA for 2013 22% higher than 2012 and slightly above the mid-range of public guidance;

- Excellent execution on announced expansion projects, with over $1 billion of capital expenditures for growth projects that were placed in service during 2013 and completed on or ahead of schedule and on or below budget, and with projects scheduled for completion in 2014 on track;

- Continued development of our potential future expansion project portfolio, with over $1.5 billion of identified growth projects;

- Tremendous effort and solid growth of our recently acquired Bakken shale midstream business; and

- A continued strong track record and performance regarding safety, with several industry safety recognitions in 2013, and compliance in all aspects of our business, including environmental and regulatory compliance.

See "—Components of Executive Compensation Program for Fiscal 2013—Annual Cash Incentive Bonus" for further discussion of these summary highlights.

Summary of 2013 and 2014 Compensation Decisions

While the compensation arrangements for our named executive officers during fiscal 2013 remained substantially similar to those in place during fiscal 2012, specific compensatory changes in 2013 included the following:

- Base salary raises were approved for certain named executive officers, ranging from 5% to 18%. Messrs. Joyce and Whalen did not receive base salary increases for 2013 at their request. The Compensation Committee authorized base salary increases for the other named executive officers in order to align the total direct compensation of these individuals more closely with the total direct compensation provided to similarly situated executives at companies within our 2013 Peer Group, adjusted for company size, and to reflect professional growth and the assumption of additional responsibilities. See "—Methodology and Process—Role of Peer Group and Benchmarking" for a description of the companies that comprise the 2013 Peer Group and of the methodology employed by BDO USA, LLC, the independent compensation consultant engaged by the Compensation Committee (the "Compensation Consultant") to adjust Peer Group total direct compensation for company size.

· Mr. Perkins's target bonus percentage for 2013 under our annual incentive plan was increased from 80% of base salary to 100% of base salary in order to align his total direct compensation more closely with the total direct compensation provided to similarly situated chief executive officers at companies within our 2013 Peer Group, adjusted for company size. For similar reasons, the long-term equity incentive award opportunity for 2013 for Messrs. Perkins and Heim was also increased.

· Provisions were added to our restricted stock awards and equity settled performance unit awards to permit continued vesting of the awards following an executive's retirement from employment with us, subject to certain conditions. Additional information is provided below under "—Components of Executive Compensation Program for Fiscal 2013—Long-Term Equity Incentive Awards—Equity-Settled Performance Unit Awards."

Consistent with, and in recognition of, our achievements in 2013 described above under "Summary of Key Strategic Results," in January 2014 the Compensation Committee approved 2013 annual cash incentive bonuses to our named executive officers at 175% of the target level. The Compensation Committee also approved base salary raises and increases in the target bonus percentages and long-term incentive plan opportunities for certain named executive officers for 2014 to bring the total direct compensation of our named executive officers more closely in line with the total direct compensation provided to similarly situated executives at companies within our 2014 Peer Group, adjusted for company size. See "—Changes for 2014" for additional information regarding base salary, target bonus percentage and long-term incentive plan opportunity increases effected for fiscal 2014 and for a description of our Peer Group companies for 2014.

Discussion and Analysis of Executive Compensation

Compensation Philosophy and Elements

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

- Competition Among Peers. The Compensation Committee believes our executive compensation program should enable us to attract and retain key executives by providing a total compensation program that is competitive with the market in which we compete for executive talent, which encompasses not only midstream natural gas companies but also other energy industry companies as described in "—Methodology and Process—Role of Peer Group and Benchmarking" below.

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

- Alignment with Shareholder Interests. The Compensation Committee believes our executive compensation program should ensure a balance between short-term and long-term compensation while emphasizing at-risk or variable compensation as a valuable means of supporting our strategic goals and aligning the interests of our named executive officers with those of our shareholders.

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

Consistent with this philosophy and the compensation objectives, our 2013 executive compensation program was comprised of the following elements of compensation:

Compensation Element	Description	Role in Total Compensation
Base Salary	Competitive fixed cash compensation based on individual's role, experience, qualifications and performance	· A core element of competitive total compensation, important in attracting and retaining key executives
Annual Cash Incentive Bonus	Variable cash payouts tied to achievement of annual financial, operational and strategic business priorities and determined in the sole discretion of the Compensation Committee	· Aligns named executive officers with annual strategic, operational and financial results · Recognizes individual and performance-based contributions to annual results · Supplements base salary to help attract and retain executives
Long-Term Equity Incentive Awards	Restricted stock awards granted under our Stock Incentive Plan Equity-settled performance unit awards granted under the Partnership's Long-Term Incentive Plan	· Aligns named executive officers with sustained long-term value creation · Creates opportunity for a meaningful and sustained ownership stake · Combined with salary and annual bonus, provides a competitive target total direct compensation opportunity substantially contingent on our performance relative to our LTIP Peer Group
Benefits	401(k) plan, health and welfare benefits	· Our named executive officers are eligible to participate in benefits provided to other Company employees · Contributes toward financial security for various life events (*e.g.*, disability or death) · Generally competitive with companies in the midstream sector
Post-Termination Compensation	"Double trigger" cash change in control payments	· Helps mitigate possible disincentives to pursue value-added merger or acquisition transactions if employment prospects are uncertain · Provides assistance with transition if post-transaction employment is not offered
Perquisites	None, other than minimal parking subsidies	· Compensation Committee's policy is not to pay for perquisites for any of our named executive officers, other than minimal parking subsidies

Fiscal 2013 Total Direct Compensation

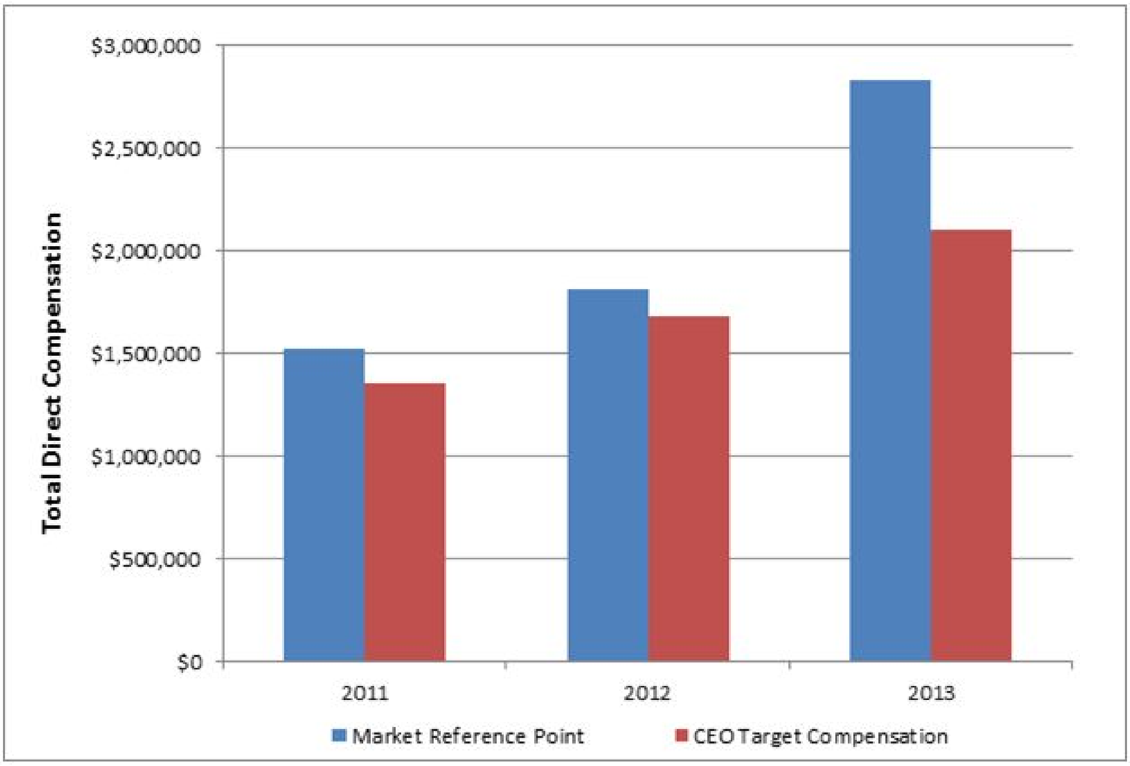
We review the mix of base salary, annual cash incentive bonuses and long-term equity incentive awards (*i.e.*, total direct compensation) each year for the Company and for our Peer Group. We view the various components of total direct compensation as related but distinct and emphasize pay for performance,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

The approximate allocation of target total direct compensation for our named executive officers in fiscal 2013 is presented below. This reflects (i) the salary rates in effect as of December 31, 2013, (ii) target annual cash incentive bonuses for services performed in fiscal 2013, and (iii) the grant date fair value of long-term equity incentive awards granted during fiscal 2013.

Fiscal 2013 Target Total Direct Compensation

	Rene J. Joyce	Joe Bob Perkins	James W. Whalen	Michael A. Heim	Matthew J. Meloy
Base Salary	26%	25%	31%	27%	38%
Annual Cash Incentive Bonus	26%	25%	25%	22%	19%
Long-Term Equity Incentive Awards	48%	50%	44%	51%	43%
Total	100%	100%	100%	100%	100%

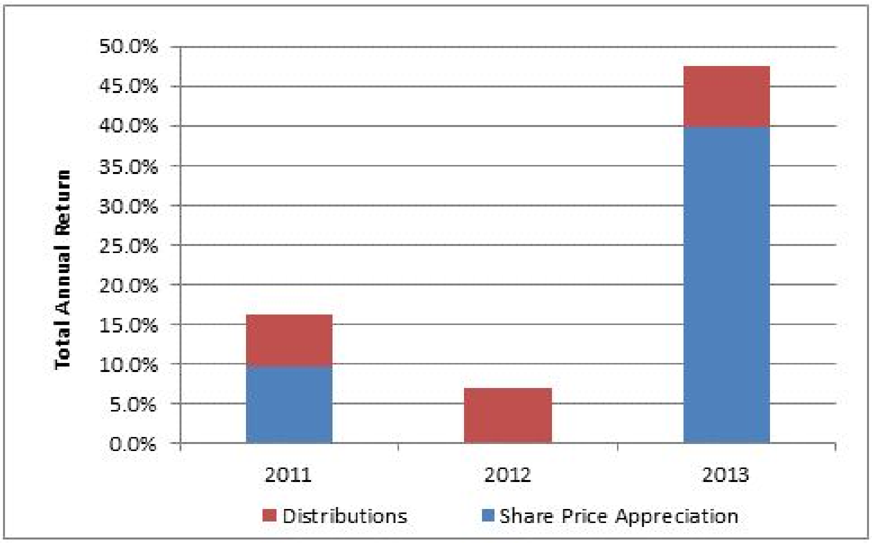
In the last three calendar years, the target total direct compensation (salary plus target bonus plus grant value of annual equity awards) available to our Chief Executive Officer has been set by the Compensation Committee at a level that is approximately 75% of the market total compensation level. Market compensation level is determined by the Compensation Consultant using a regression analysis for our Peer Group that adjusts for company size and that predicts total direct compensation as correlated to market capitalization and total assets. The following chart illustrates the relationship between the target total direct compensation available to our Chief Executive Officer and the market level developed by our Compensation Consultant for the last three years. The compensation shown for the Chief Executive Officer in 2011 relates to the last year Mr. Joyce served in that capacity. Mr. Perkins became the Chief Executive Officer effective January 1, 2012.



Because incentive compensation (*i.e.*, target annual cash incentive bonus and grant date fair value of long-term equity incentive awards) comprised 75% of our Chief Executive Officer's total compensation opportunity for 2013, the amount of compensation he ultimately realizes from these awards may be more or less than the target amount as determined in particular by our Compensation Committee's evaluation of our performance, the total unitholder return on the Partnership's common units on both an absolute basis and relative to peer companies and the total shareholder return on our common stock.

Annual Total Unit Holder Return

In the last three calendar years, we have delivered annual total returns to our unit holders of 47.5% (for 2013), 7.1% (for 2012) and 16.4% (for 2011).



Methodology and Process

Role of Compensation Consultant in Setting Compensation

The Compensation Committee retained BDO USA, LLP as its independent Compensation Consultant to advise the Compensation Committee on matters related to executive and non-management director compensation for 2013. During 2012 and 2013, the Compensation Committee received advice from the Compensation Consultant with respect to the development and structure of our 2013 executive compensation program. The Compensation Committee has concluded that we do not have any conflicts of interest with the Compensation Consultant.

Role of Peer Group and Benchmarking

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

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

To reflect the market in which we compete for executive talent, the Peer Group considered by the Compensation Committee in consultation with senior management for compensation comparison purposes each year includes companies in three comparator groups: (1) midstream master limited partnerships ("MLPs"), (2) exploration and production companies ("E&Ps"), and (3) energy utilities. Our analysis places greater weight on the compensation data reported by other publicly-traded midstream MLPs. E&Ps and utilities selected for the Peer Group, in the Compensation Committee's opinion, provide relevant reference points because they have similar or related operations, compete in the same or similar markets, face similar regulatory challenges and require similar skills, knowledge and experience of their executive officers as we require of our executive officers.

Because many companies in the Peer Group may be larger than we are as measured by market capitalization and total assets, with the assistance of the Compensation Consultant, compensation data for the Peer Group companies is analyzed using multiple regression analysis to develop a prediction of the total compensation that Peer Group companies of comparable size to us would offer similarly-situated executives. The regressed data is analyzed separately for each of the three comparator groups and is then weighted as follows to develop a reference point for assessing our total executive pay opportunity relative to market practice: (1) MLPs (given a 70% weighting), (2) E&Ps (given a 15% weighting) and (3) utility companies (given a 15% weighting). For 2013, the "Peer Group" companies (for purposes of determining 2013 compensation levels) were:

- *MLP peer companies*: Atlas Pipeline Partners, L.P., Copano Energy, L.L.C., Crosstex Energy, L.P., DCP Midstream Partners, LP, Enbridge Energy Partners L.P., Energy Transfer Partners, L.P., Enterprise Products Partners L.P., Magellan Midstream Partners, L.P., MarkWest Energy Partners, L.P., NuStar Energy L.P., ONEOK Partners, L.P., Plains All American Pipeline, L.P., Regency Energy Partners LP and Williams Partners L.P.

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

- *Utility peer companies*: CenterPoint Energy, Inc., Dominion Resources Services, Inc., Enbridge Inc., EQT Corporation, National Fuel Gas Company, NiSource Inc., ONEOK, Inc., Questar Corporation, Sempra Energy, Spectra Energy Company, TransCanada Corporation and The Williams Companies Inc.

Based upon the recommendation of our Compensation Consultant, we made the following changes to the 2012 Peer Group to create the 2013 Peer Group: (i) removed two companies, Petrohawk Energy Corp. and Southern Union Co., which are no longer publicly traded, and (ii) added Plains All American Pipeline, L.P.

Senior management and the Compensation Committee review our compensation-setting practices and Peer Group companies on at least an annual basis. See "Changes for 2014" for a description of the changes that were made to the Peer Group for 2014 compensation purposes.

Role of Senior Management in Establishing Compensation for Named Executive Officers

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

The Chairman of the Compensation Committee reviews and discusses the proposal with senior management and the Compensation Consultant and may discuss it with the other members of the Compensation Committee, other members of the Board of Directors, the full Board of Directors and/or the full board of directors of the general partner. The Chairman of the Compensation Committee may request that senior management provide him with additional information or reconsider or revise the proposal. The resulting recommendation is then submitted to the full Compensation Committee for consideration, which typically invites other members of the Board of Directors and the directors of the general partner, and also meets separately with the Compensation Consultant. The final compensation decisions are reported to the Board of Directors.

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

Components of Executive Compensation Program for Fiscal 2013

Base Salary

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

For 2013, the Compensation Committee authorized increases in base salary for certain of our named executive officers, effective March 1, 2013, as set forth in the following table. Salaries were increased to better align total direct compensation opportunities with the target total direct compensation provided to similarly situated executives at companies within our 2013 Peer Group, adjusted for company size and, in the case of Messrs. Perkins and Meloy, to reflect increased responsibilities within the organization. Messrs. Joyce and Whalen did not receive a base salary increase for 2013 at their request.

	Prior Salary	Base Salary Effective March 1, 2013	Percent Increase
Rene R. Joyce	$ 560,000	$ 560,000	0%
Joe Bob Perkins	480,000	525,000	9%
James W. Whalen	480,000	480,000	0%
Michael A. Heim	460,000	485,000	5%
Matthew J. Meloy	275,000	325,000	18%

Annual Cash Incentive Bonus

For 2013, our named executive officers were eligible to receive annual cash incentive bonuses under the 2013 Annual Incentive Plan (the "2013 Bonus Plan"), which was approved by the Compensation Committee in January 2013. The funding of the cash bonus pool and the payment of individual cash bonuses to executive management, including our named executive officers, are subject to the sole discretion of the Compensation Committee and will generally be determined near or following the end of the year to which the bonus relates.

The target amount of the cash bonus pool for all employees is equal to the sum of the target bonus amounts for all participants in the 2013 Bonus Plan. Each participant's target bonus amount is equal to the product of the participant's base salary (at the rate in effect as of the last day of the year to which the bonus relates) and the participant's target bonus percentage, which may generally range from 6% to 100%. For purposes of the 2013 Bonus Plan, the percentage of base salary that was set as the "target" amount for each named executive officer's bonus was as follows:

	Target Bonus Percentage (as a % of Base Salary)	Target Bonus Amount
Rene R. Joyce	100%	$ 560,000
Joe Bob Perkins	100%	525,000
James W. Whalen	80%	384,000
Michael A. Heim	80%	388,000
Matthew J. Meloy	50%	162,500

For 2013, Mr. Perkins's target bonus percentage was increased from 80% to 100% to align his total direct compensation more closely with the total direct compensation provided to similarly situated chief executive officers at companies within our Peer Group, adjusted for company size. The target bonus percentages for the other named executive officers did not change from the level in effect in 2012.

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

The Compensation Committee, after consultation with the Chief Executive Officer, established the following overall threshold, target and maximum levels for the 2013 Bonus Plan: (i) 50% of the target amount of the cash bonus pool would be funded in the event that the Compensation Committee determined that our business priorities had been met for the year at a threshold level; (ii) 100% of the target amount of the cash bonus pool would be funded in the event that the Compensation Committee determined that our business priorities had been met for the year at a target level; and (iii) 200% of the target amount of the cash bonus pool would be funded in the event that the Compensation Committee determined that our business priorities had been met for the year at a maximum level. While the established threshold, target and maximum levels provide general guidelines in determining the funding level of the cash bonus pool each year, senior management recommends a funding level to the Compensation Committee based on our achievement of specified business priorities for the year, and the Compensation Committee ultimately determines the total amount to be allocated to the cash bonus pool in its sole discretion based on its assessment of the business priorities and our overall performance for the year.

For purposes of determining the actual funding level of the cash bonus pool and the amount of individual bonus awards under the 2013 Bonus Plan, the Compensation Committee focused on the business priorities listed in the table below. These priorities are not objective in nature; they are subjective, and performance in regard to these priorities is ultimately evaluated by the Compensation Committee in its sole discretion. As such, success does not depend on achieving a particular target; rather, success is evaluated based on past norms, expectations and unanticipated obstacles or opportunities that arise. For example, hurricanes and deteriorating or changing market conditions may alter the priorities initially established by the Compensation Committee such that certain performance that would otherwise be deemed a negative may, in context, be a positive result. This subjectivity allows the Compensation Committee to account for the full industry and economic context of our actual performance and that of our personnel. The Compensation Committee considers all strategic priorities and reviews performance against the priorities and context but does not apply a formula or assign specific weightings to the strategic priorities in advance.

<table>
<tr><th>2013 Business Priority</th><th>Committee Consensus</th><th>Overall Assessment</th></tr>
<tr><td>Continue to control all operating, capital and general and administrative (“G&A”) costs</td><td>Exceeded</td><td rowspan="10">· On balance, excellent execution across our businesses, including strong financial performance, with the Partnership’s Adjusted EBITDA for 2013 22% higher than 2012 and slightly above the mid-range of public guidance:
o Excellent execution on: volume growth for Field Gathering and Processing, fractionation and exports; major project execution; expense control; distribution and dividend growth; credit, inventory, hedging and balance sheet management; and capital markets execution, including equity under the Partnership’s “At the Market” equity sales program
o Somewhat offset by lower Coastal Gathering and Processing volumes, project delays at Sound and Channelview and startup / integration challenges at Badlands

· Excellent execution on announced expansion projects including: Phase I of the low ethane propane export project; CBF Train 4 expansion, and High Plains Plant, Longhorn Plant and Phase II of the low ethane propane export project under construction; over $1 billion of capital expenditures for growth projects placed in service during 2013 that were completed on or ahead of schedule and on or below budget; projects scheduled for completion in 2014 on track

· Continued development of our potential future expansion project portfolio, with over $1.5 billion of identified growth projects, including: CBF Train 5; condensate splitter; potential pipeline and/or processing plant projects in the Permian Basin; and additional processing in Badlands

· Tremendous effort and solid growth of Badlands operations in the Bakken in challenging environment: including producer deals and connections, progress on growth projects and strong year-end volume ramp

· Strong track record and performance regarding safety and compliance in all aspects of our business, including environmental and regulatory compliance; continued industry recognition through safety awards

· Expansion construction programs in 2013 involved over 2000 contractor full time equivalents at our facilities with no significant safety incidents</td></tr>
<tr><td>Continue priority emphasis and strong performance relative to a safe workplace</td><td>Exceeded</td></tr>
<tr><td>Reinforce business philosophy and mindset that promotes compliance with all aspects of our business including environmental and regulatory compliance</td><td>Achieved</td></tr>
<tr><td>Continue to tightly manage credit, inventory, interest rate and commodity price exposures</td><td>Achieved</td></tr>
<tr><td>Execute on major capital and development projects, such as finalizing negotiations, completing projects on time and on budget, and optimizing economics and capital funding</td><td>Exceeded</td></tr>
<tr><td>Pursue selected growth opportunities, including new gathering and processing build-outs, fee-based capital expenditure projects and potential purchases of strategic assets</td><td>Exceeded</td></tr>
<tr><td>Pursue commercial and financial approaches to achieve maximum value and manage risks</td><td>Exceeded</td></tr>
<tr><td>Execute on all business dimensions, including 2013 guidance for EBITDA and distribution / dividend growth as furnished from time to time</td><td>Exceeded</td></tr>
<tr><td>Successfully integrate and commercialize the Bakken Shale midstream business including contribution to 2013 guidance</td><td>Achieved</td></tr>
<tr><td>Continue to attract and retain needed operational and professional talent</td><td>Achieved</td></tr>
</table>

After assessing the results of the 2013 business priorities as summarized above, in January 2014 the Compensation Committee, in its sole discretion, approved a cash bonus pool equal to 175% of the target level under the 2013 Bonus Plan. The Compensation Committee determined to fund the bonus pool above the target level because it considered overall performance, including organizational performance, to have substantially exceeded expectations based on its assessment of the 2013 business priorities.

This subjective assessment that performance substantially exceeded expectations was based on a qualitative evaluation rather than a mechanical, quantitative determination of results across each of the business priorities, and occurred with the background and ongoing context of (i) refinements of the 2013 business priorities by the Board of Directors and the Compensation Committee, (ii) continued discussion and active dialogue between the Board of Directors and the Compensation Committee and management about priorities and performance, including routine reports sent to the Board of Directors and the Compensation Committee, (iii) detailed monthly performance communications to the Board of Directors, (iv) presentations and discussions in subsequent Board of Directors and Compensation Committee meetings, and (v) further discussion among the Board of Directors and Compensation Committee of our performance relative to expectations near the end and following the end of 2013. The extensive business and board of director experience of the members of the Compensation Committee and of our Board of Directors provides the perspective to make this subjective assessment in a qualitative manner and to evaluate management performance overall and the performance of individual executive officers.

In connection with determining the funding level of the cash bonus pool, the Compensation Committee also determined the amount of the annual cash incentive bonus payments to be made to each named executive officer under the 2013 Bonus Plan based on an evaluation of the executive group and each officer's individual performance for the year. Because the funding level of the cash bonus pool was set at 175% of the target amount, each named executive officer was awarded a bonus amount equal to 175% of his respective target bonus amount, multiplied by a designated multiple determined by the Compensation Committee for each named executive officer based on his individual performance. The Compensation Committee determined that a performance multiplier of 1.25x should be applied to Mr. Meloy's bonus amount for the year, based on his individual performance including his role in leading the Partnership's capital market activities during 2013 and in leading our and the Partnership's overall financial strategies. All other named executive officers received a 1.0x multiplier. The dollar amounts of the annual cash incentive bonus awards received by the named executive officers under the 2013 Bonus Plan to be paid by February 28, 2014 are as follows:

	Target Bonus Amount	Individual Performance Factor	Company Performance Factor	Actual Bonus Amount
Rene R. Joyce	$ 560,000	1.0	1.75	$ 980,000
Joe Bob Perkins	525,000	1.0	1.75	918,750
James W. Whalen	384,000	1.0	1.75	672,000
Michael A. Heim	388,000	1.0	1.75	679,000
Matthew J. Meloy	162,500	1.25	1.75	355,469

Long-Term Equity Incentive Awards

In connection with our initial public offering in December 2010, we adopted the 2010 Stock Incentive Plan (the "Stock Incentive Plan") under which we may grant to the named executive officers, other key employees, consultants and directors certain equity-based awards, including restricted stock, restricted stock units, bonus stock and performance-based awards. In addition, the general partner sponsors and maintains the Targa Resources Partners Long-Term Incentive Plan (the "Long-Term Incentive Plan"), under which the general partner may grant equity-based awards related to the Partnership's common units to individuals, including the named executive officers, who provide services to the Partnership.

The Compensation Committee determines the amount of long-term equity incentive awards under the Stock Incentive Plan and recommends to the board of directors of the general partner an amount of long-term equity incentive awards under the Partnership's Long-Term Incentive Plan that it believes is appropriate as a component of total compensation for each named executive officer for a given year based on its decisions regarding each named executive officer's total compensation targets. The Long-Term Incentive Plan awards are ultimately determined and approved by the general partner's board of directors. Long-term incentive awards to our named executive officers under the Stock Incentive Plan and the Long-Term Incentive Plan are made near the beginning of each year.

For 2013, the value of the long-term equity incentive component of our named executive officers' compensation was allocated approximately (i) twenty-five (25%) to restricted stock awards under the Stock Incentive Plan and (ii) seventy-five (75%) to equity-settled performance unit awards under the Partnership's Long-Term Incentive Plan. This allocation is based on the dollar value of the awards on the date of grant. The total dollar value of long-term equity incentive awards for each named executive officer for a given year is typically equal to a specified percentage of the officer's base salary; however, the Compensation Committee may, in its discretion, award additional long-term equity incentive awards if deemed appropriate. The number of shares or units subject to each award is determined by dividing the total dollar value allocated to the award by the ten day average closing price of the shares or units for the period ending five business days prior to the date of grant. For 2013, the specified percentage of each named executive officer's base salary used for purposes of determining the amount of long-term equity incentive awards granted and the corresponding dollar values as of the date of grant are set forth in the following table:

	Percentage of Base Salary	Total Dollar Value of Long-Term Equity Incentive Awards as of the Date of Grant
Rene R. Joyce	190%	$ 1,064,000
Joe Bob Perkins	200%	$ 1,050,000
James W. Whalen	143%	$ 686,400
Michael A. Heim	190%	$ 921,500
Matthew J. Meloy	115%	$ 373,750

For Messrs. Perkins, Heim and Meloy, the base salary percentages used to determine the dollar values of the long-term equity incentive awards were increased from the percentages used in 2012 (170%, 155% and 110%, respectively) to align their total direct compensation more closely with similarly situated executives at companies within our 2013 Peer Group, adjusted for company size. The percentages for the other named executive officers were unchanged from those used in 2012.

The Compensation Committee believes that the combination of equity awards consisting of restricted stock or restricted stock units (25% of award value) and equity-settled performance units (75% of award value) granted to our named executive officers provides a balance of performance-based long-term incentives and of parent and subsidiary MLP equity. The restricted stock or restricted stock unit awards are time-based awards that capture absolute total return performance of our common stock, and the equity-settled performance unit awards reflect both the absolute total return of the Partnership's common units with variable performance based on the total return of the Partnership's units in relation to the LTIP Peer Group (defined below). Also, this mix effectively aligns the named executive officer's interests with both the interests of our stockholders and the interests of the Partnership's unitholders. The Compensation Committee allocates a larger portion of each named executive officer's long-term equity incentive compensation to equity-settled performance unit awards because these awards link executive compensation not only to the value of Partnership equity over time, but also to the relative performance of the Partnership compared to other midstream partnerships with which the Partnership competes.

Restricted Stock Awards. On January 15, 2013, our named executive officers were awarded restricted shares of our common stock under the Stock Incentive Plan in the following amounts: (i) 4,960 restricted shares to Mr. Joyce, (ii) 4,895 restricted shares to Mr. Perkins, (iii) 3,200 restricted shares to Mr. Whalen, (iv) 4,296 restricted shares to Mr. Heim, and (v) 1,742 restricted shares to Mr. Meloy. These restricted stock awards vest in full on the third anniversary of the grant date, subject to the officer's continued service. Accelerated vesting provisions applicable to these awards in the event of certain terminations of employment and/or a change in control are described in detail below under "—Potential Payments Upon Termination or Change in Control—Stock Incentive Plan." During the period the restricted shares are outstanding and unvested, we accrue any dividends paid by us in an amount equal to the dividends paid with respect to a share of common stock times the number of restricted shares awarded. At the time the restricted shares vest, the named executive officers will receive a cash payment equal to the amount of dividends accrued with respect to such named executive officer's vested shares.

On July 15, 2013, we approved amendments to our outstanding restricted stock awards granted in 2011, 2012 and 2013, including awards to our executive officers, to permit continued vesting of the awards following retirement. The amendments provide that an executive's awards will continue to vest on the third anniversary of the grant date if, from the date of the executive's retirement through the third anniversary date, the executive has either performed consulting services for us or refrained from working for one of our competitors or in a similar role for another company; however, directorships at non-competitors are permitted. These revised vesting provisions also apply to future equity awards granted following July 15, 2013, including the restricted stock unit awards described below under "—Changes for 2014—Long-Term Equity Incentive Awards." In deciding to adopt the amendments, the Compensation Committee consulted with the Compensation Consultant, who reviewed industry practices regarding vesting at or during retirement and advised the committee that a majority of companies allow awards to either vest fully or vest pro rata upon retirement, while a minority of companies require forfeiture of awards. Senior management proposed the continued vesting of awards for all employees following retirement if certain service-related conditions are met, as opposed to automatic accelerated vesting at the retirement date, so that our company would be able to benefit from employee non-compete obligations and ongoing access to cooperative former employees. The Compensation Committee agreed that the continued vesting construct was the most desirable and appropriate approach for our company and approved these changes to the vesting schedule of the restricted stock awards to further align our executives' interests with those of our shareholders and to help attract and retain key employees.

Beginning in 2014, we will award restricted stock units under the Stock Incentive Plan instead of restricted stock. See “—Changes for 2014—Long-Term Equity Incentive Awards” for additional information regarding our decision to award restricted stock units.

Equity-Settled Performance Unit Awards. Our named executive officers also receive annual awards of equity-settled performance unit awards under the Partnership’s Long-Term Incentive Plan. The vesting of these awards is dependent on the satisfaction of certain service-related conditions and the Partnership’s performance relative to the performance of a specified comparator group of publicly-traded partnerships (the “LTIP Peer Group”). The LTIP Peer Group is not composed of the same companies as the peer group companies employed for developing market reference points for executive pay because the companies in those groups are those with which we compete for executive talent. Companies in the LTIP Peer Group are principally those companies with which the Partnership competes to varying extents in the midstream sector. The performance unit awards, which are settled in Partnership common units, are designed to align the interests of the named executive officers and other key employees with those of the Partnership’s equity holders.

On January 15, 2013, our named executive officers were awarded equity-settled performance units under the Partnership’s Long-Term Incentive Plan in the following amounts: (i) 21,251 performance units to Mr. Joyce, (ii) 20,971 performance units to Mr. Perkins, (iii) 13,709 performance units to Mr. Whalen, (iv) 18,405 performance units to Mr. Heim, and (v) 7,465 performance units to Mr. Meloy.

The performance period for the 2013 performance unit awards began on June 30, 2013 and ends on June 30, 2016. Provided a named executive officer remains continuously employed throughout the performance period, his 2013 performance units will vest on June 30, 2016 and will be settled as soon as practicable following the vesting date by the issuance of Partnership common units. As with the outstanding restricted stock awards, on July 15, 2013, the Partnership approved amendments to outstanding equity-settled performance unit awards granted in 2011, 2012 and 2013, including awards to our executive officers, to permit continued vesting of the awards following retirement. The amendments provide that an executive’s awards will continue to vest on the last day of the applicable performance period if, from the date of the executive’s retirement through the last day of the performance period, the executive has either performed consulting services for us or refrained from working for one of our competitors or in a similar role for another company; however, directorships at non-competitors are permitted. The performance unit awards remain subject to applicable performance based vesting requirements during the post-retirement period. These revised vesting provisions also apply to future performance unit awards granted following July 15, 2013 but were not applicable to the 2010 awards that vested in June 2013. For a discussion of the rationale for these changes, see “—Components of Executive Compensation Program for Fiscal 2013—Long-Term Equity Incentive Awards—Restricted Stock Awards.”

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

For the 2013 performance unit awards, the LTIP Peer Group is composed of the Partnership and the following other companies (ticker noted in parenthesis):

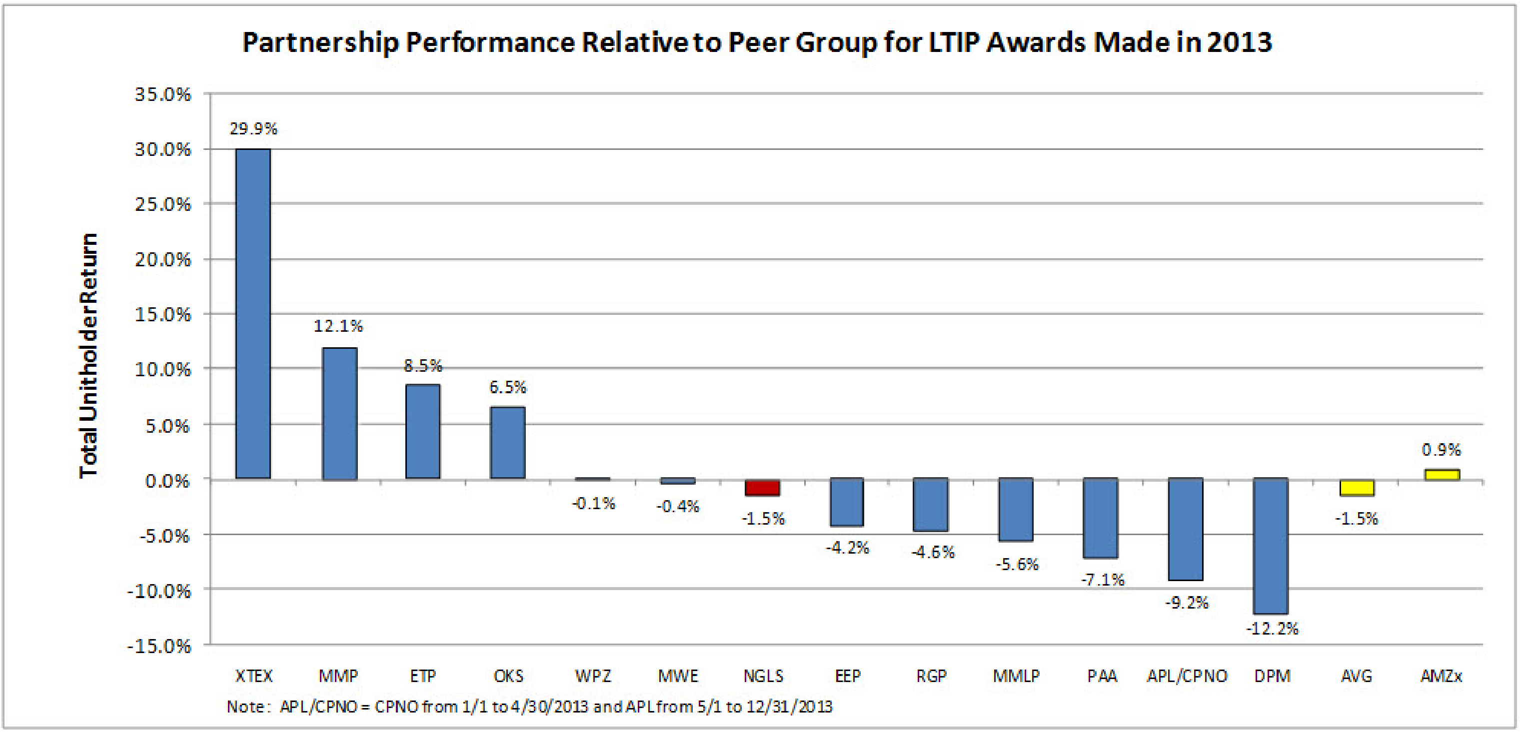
Atlas Pipeline Partners, L.P. (APL)	MarkWest Energy Partners, L.P. (MWE)
Crosstex Energy, L.P. (XTEX)	Martin Midstream Partners L.P. (MMLP)
DCP Midstream Partners, LP (DPM)	ONEOK Partners, L.P. (OKS)
Enbridge Energy Partners L.P. (EEP)	Plains All American Pipeline L.P. (PAA)
Energy Transfer Partners, L.P. (ETP)	Regency Energy Partners LP (RGP)
Magellan Midstream Partners, L.P. (MMP)	Williams Partners L.P. (WPZ)

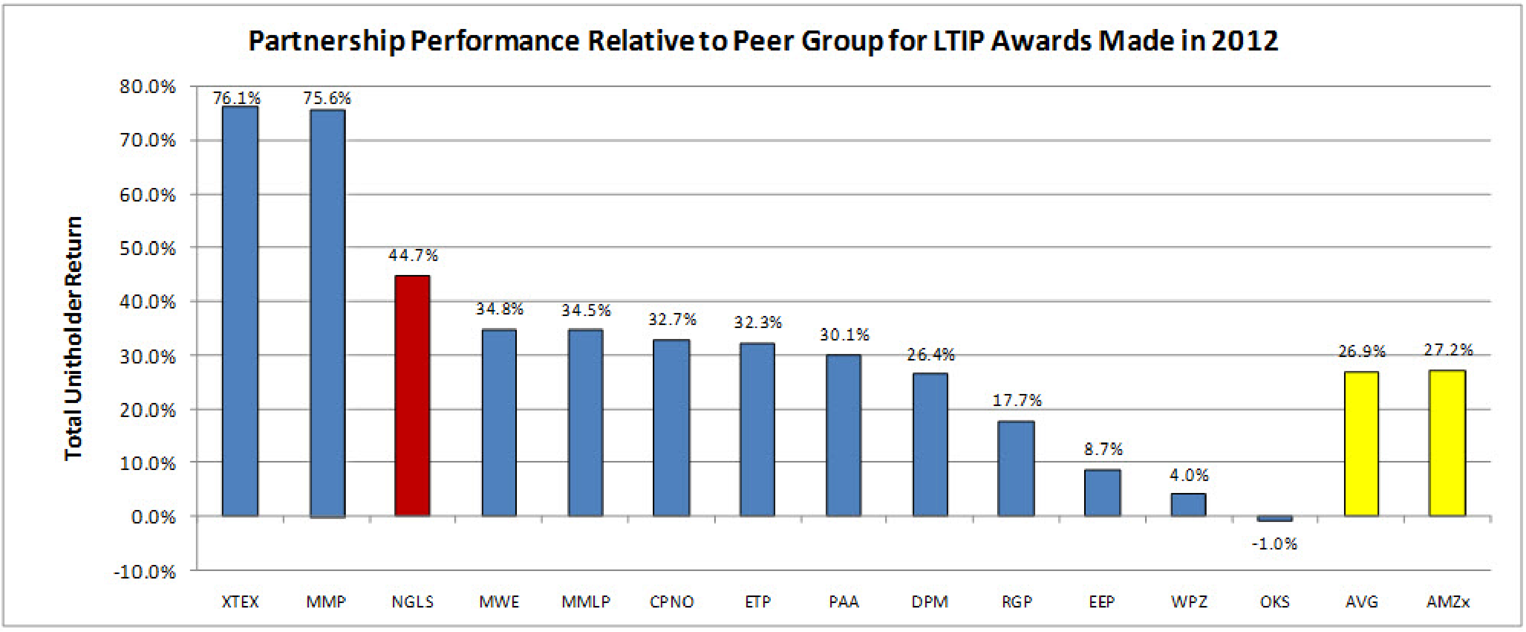
The board of directors of the general partner has the ability to modify the LTIP Peer Group in the event a company listed above ceases to be publicly traded or another significant event occurs and a company is determined to no longer be one of the Partnership's peers. Effective May 1, 2013, the Compensation Committee removed Copano Energy, L.L.C. ("Copano") from the LTIP Peer Group due to its acquisition by Kinder Morgan Energy Partners L.P. as of that date. Copano was replaced with Atlas Pipeline Partners L.P. ("Atlas"), as reflected above. For the 2010 performance unit awards that vested in June 2013, Copano's performance through May 1, 2013, including the acquisition premium, was used for the peer group performance ranking in determining vesting. For outstanding 2011 and 2012 performance unit awards, Copano will remain in the peer group through May 1, 2013, and Atlas will be substituted for Copano's position in the performance ranking as of May 2, 2013.

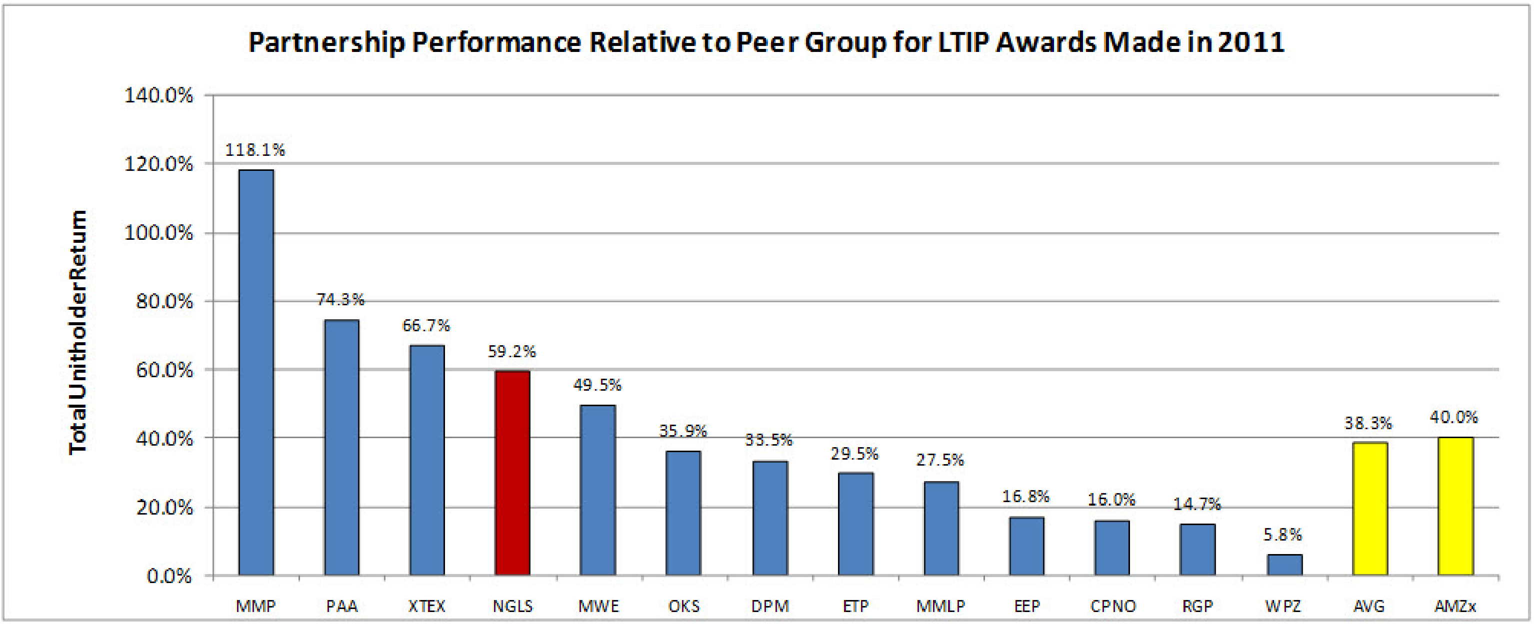
For purposes of the performance unit awards, the Partnership's performance is determined based on the comparison of "total return" of a Partnership common unit for the performance period to the "total return" of a common share/unit of each member of the LTIP Peer Group for the performance period. "Total return" is measured by (i) subtracting (a) the average closing price per share/unit for the first ten trading days of the performance period (the "Beginning Price") from (b) the sum of (1) the average closing price per share/unit for the last ten trading days of the performance period, plus (2) the aggregate amount of dividends/distributions paid with respect to a share/unit during such period (such result is referred to as the "Value Increase"), and (ii) dividing the Value Increase by the Beginning Price. In connection with the amendments to allow continued vesting of the performance unit awards following retirement, we also amended the dates used to calculate "total return" as described above. Prior to the amendment, the Value Increase was determined using the average closing price per share/unit for the ten trading days ending fifteen days prior to the last trading day of the performance period. The Compensation Committee determined that the change was warranted in order to capture performance over the full period and that it would apply to all future awards, as well as awards granted in 2011, 2012 and 2013 but not to the 2010 awards that vested in June 2013.

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

The following charts illustrate the total return for the Partnership's common units compared to the total return of each other company in the LTIP Peer Group and of the Alerian MLP Index (AMZx) measured over the period beginning on June 30 of each year in which the long-term incentive awards were made, using the Beginning Price described above, and continuing through December 31, 2013.







Partnership Performance Relative to Peer Group for LTIP Awards Made in 2011
Total Unitholder Return
140.0%
120.0%
100.0%
80.0%
60.0%
40.0%
20.0%
0.0%
118.1%
74.3%
66.7%
59.2%
49.5%
35.9%
33.5%
29.5%
27.5%
16.8%
16.0%
14.7%
5.8%
38.3%
40.0%
MMP
PAA
XTEX
NGLS
MWE
OKS
DPM
ETP
MMLP
EEP
CPNO
RGP
WPZ
AVG
AMZx

With respect to the 2010 equity-settled performance unit awards, which have a performance period that ended June 30, 2013, the Partnership's total return rank was fourth among the LTIP Peer Group, and the Compensation Committee certified that the performance goal was achieved with a 107.96% total return, resulting in a performance vesting percentage of 142.9%. See "Option Exercises and Stock Vested in 2013" for more information.

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

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

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

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

Changes for 2014

In consultation with the Compensation Consultant, the Compensation Committee has reviewed our executive compensation program and has made certain changes for 2014, which are described in more detail below. The analysis provided by the Compensation Consultant indicated that the compensation of chief executive officers and chief financial officers at companies within our 2014 Peer Group has substantially increased over the 2013 levels. Specifically, the analysis provided to the Compensation Committee by the Compensation Consultant indicates that the current total target direct compensation of our Chief Executive Officer remains more than 35% below the competitive market level adjusted for company size using the regression analysis of 2014 Peer Group pay programs.

In order to align the total compensation of our named executive officers more closely with that of similarly situated officers within the 2014 Peer Group, we have generally made modest increases in the salary levels and more substantial increases in the incentive based compensation opportunities of certain named executive officers.

Base Salary

The Compensation Committee authorized, and executive management will implement, the following base salaries for our named executive officers effective March 1, 2014:

Name	Effective March 1, 2014	Current Salary
Rene R. Joyce	$ 560,000	$ 560,000
Joe Bob Perkins	560,000	525,000
James W. Whalen	430,000	480,000
Michael A. Heim	535,000	485,000
Matthew J. Meloy	375,000	325,000

Mr. Joyce did not receive a base salary increase for 2014 at his request and Mr. Whalen's base salary was reduced approximately 10% at his request to reflect a reduced work schedule in 2014. The Compensation Committee authorized base salary increases for other named executive officers along with adjustments in annual cash bonus incentive targets and grant date values of long-term incentives in order to align the total direct compensation of these individuals more closely with the total direct compensation provided to similarly situated executives at companies within our 2014 Peer Group, adjusted for company size, and to reflect professional growth and the assumption of additional responsibilities.

Annual Cash Incentive Bonus

In preparing our business plan for 2014, senior management developed and proposed a set of business priorities to the Compensation Committee. The Compensation Committee discussed and adopted the business priorities proposed by senior management for purposes of the 2014 Annual Incentive Plan (the "2014 Bonus Plan"). The 2014 business priorities are similar to those in effect for 2013 and have been revised to reflect our goal of continuing the expansion and commercialization of our recently acquired Bakken shale midstream business, and specifically include the following:

- execute on all business dimensions, including 2014 guidance for EBITDA and distribution/dividend growth as furnished from time to time;
- continue the expansion of system capabilities and the commercialization of our Bakken shale midstream business including volume targets for 2014;
- continue priority emphasis and strong performance relative to a safe workplace;
- reinforce business philosophy and mindset that promotes compliance in all aspects of our business including environmental and regulatory compliance;
- continue to attract and retain the operational and professional talent needed in our businesses;
- continue to control all costs—operating, capital and G&A;
- continue to manage tightly credit, inventory, interest rate and commodity price exposures;
- execute on major capital and development projects—finalizing negotiations, completing projects on time and on budget, and optimizing economics and capital funding;
- pursue selected growth opportunities including G&P build outs, fee-based capex projects, and potential purchases of strategic assets; and
- pursue commercial and financial approaches to achieve maximum value and manage risks.

The overall threshold, target and maximum funding percentages for the 2014 Bonus Plan remain the same as for the 2013 Bonus Plan. The target bonus percentage (as a percentage of base salary) for Mr. Heim and Mr. Meloy has been increased for 2014. As with the 2013 Bonus Plan, funding of the cash bonus pool and the payment of individual cash bonuses to executive management, including our named executive officers, is subject to the sole discretion of the Compensation Committee.

The following table shows the target bonus percentages for our named executive officers effective March 1, 2014:

Name	Effective March 1, 2014	Current Percentage
Rene R. Joyce	100%	100%
Joe Bob Perkins	100%	100%
James W. Whalen	80%	80%
Michael A. Heim	90%	80%
Matthew J. Meloy	75%	50%

Long-Term Equity Incentive Awards

For 2014, the Compensation Committee approved increases in the percentage of base salary used to determine the total dollar value of the annual long-term equity incentive awards granted to Mr. Perkins, Mr. Heim and Mr. Meloy.

The following table shows the percentages used for long-term incentive awards for our named executive officers effective March 1, 2014:

Name	Effective March 1, 2014	Current Percentage
Rene R. Joyce	190%	190%
Joe Bob Perkins	300%	200%
James W. Whalen	143%	143%
Michael A. Heim	225%	190%
Matthew J. Meloy	150%	115%

The value of long-term equity incentive awards for 2014, as in 2013, was allocated approximately (i) twenty-five percent (25%) to awards under the Stock Incentive Plan, and (ii) seventy-five percent (75%) to awards under the Partnership's Long-Term Incentive Plan, as described in greater detail below.

Restricted Stock Unit Awards. In 2013 and prior years, the Compensation Committee awarded restricted stock awards to the named executive officers under the terms of our Stock Incentive Plan. For 2014, the Compensation Committee determined to award restricted stock units, which will settle in shares of our common stock, instead of restricted stock awards. The terms and conditions of the restricted stock unit awards are substantially similar to the terms and conditions of the previously granted restricted stock awards, except that under the restricted stock unit awards, shares of stock are not delivered until the awards vest. The Compensation Committee determined that the use of restricted stock units provided greater design flexibility in our equity award program than restricted stock awards. On January 14, 2014, our named executive officers were awarded equity-settled restricted stock units under the Stock Incentive Plan in the following amounts: (i) 3,054 restricted stock units to Mr. Joyce, (ii) 4,823 restricted stock units to Mr. Perkins, (iii) 1,765 restricted stock units to Mr. Whalen, (iv) 3,456 restricted stock units to Mr. Heim, and (v) 1,615 restricted stock units to Mr. Meloy. These restricted stock units vest in full on the third anniversary of the grant date, subject to the officer's continued service or fulfillment of certain service related requirements following retirement.

Equity-Settled Performance Unit Awards. On January 14, 2014, our named executive officers were awarded equity-settled performance units under the Partnership's Long-Term Incentive Plan in the following amounts: (i) 15,503 performance units to Mr. Joyce, (ii) 24,478 performance units to Mr. Perkins, (iii) 8,959 performance units to Mr. Whalen, (iv) 17,539 performance units to Mr. Heim, and (v) 8,196 performance units to Mr. Meloy. The vesting and settlement value of these performance unit awards will be determined using the formula adopted for the performance unit awards granted on January 15, 2013 (taking into account the July 2013 amendments), except that the performance period for the 2014 awards will begin on June 30, 2014 and end on June 30, 2017. Please see "—Components of Executive Compensation Program for Fiscal 2013—Long-Term Equity Incentive Awards—Equity-Settled Performance Unit Awards."

2014 Peer Group

The Peer Group companies we have historically used for compensation comparison purposes have remained fundamentally unchanged since our current approach using regression analysis was developed in 2010. During 2013, we worked with our Compensation Consultant to make a number of changes to the composition of our Peer Group used for 2014 compensation purposes in order to create more balance in the make-up of the Peer Group. Based upon the recommendation of our Compensation Consultant, we made the following changes to the 2013 Peer Group to create the 2014 Peer Group: (i) removed two companies—El Paso Corporation and Copano Energy, L.L.C.—that are no longer publicly traded, (ii) removed two companies which are "sponsored" MLPs for which relevant information is not publicly available— ONEOK Partners, L.P. and Williams Partners L.P.—and replaced them with their publicly traded general partners (the two general partners were then moved from our utility comparator group to our MLP comparator group), (iii) removed certain companies that were no longer considered to be appropriate for compensation comparison purposes for other reasons, such as being either too large or too small, and (iv) added new companies that are better alternatives to replace the companies that were removed in order to increase the number of companies in each comparator group to fifteen. After these adjustments, the 2014 Peer Group companies (for purposes of determining 2014 compensation levels) are:

- *MLP peer companies*: Access Midstream Partners, L.P., Atlas Pipeline Partners, L.P., Buckeye Partners, L.P., Crosstex Energy, L.P., DCP Midstream Partners, LP, Enbridge Energy Partners L.P., Energy Transfer Partners, L.P., Enterprise Products Partners L.P., Genesis Energy, L.P., Magellan Midstream Partners, L.P., MarkWest Energy Partners, L.P., NuStar Energy L.P., ONEOK, Inc., Plains All American Pipeline, L.P., Regency Energy Partners LP and Williams Companies, Inc.

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

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

Other Compensation Matters

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

Clawback Policy. To date, we have not adopted a formal clawback policy to recoup incentive based compensation upon the occurrence of a financial restatement, misconduct, or other specified events. However, restricted stock and/or restricted stock unit agreements covering grants made to our named executive officers and other employees in 2011 and later years do include language providing that any compensation, payments or benefits provided under such an award (including profits realized from the sale of earned shares) are subject to clawback to the extent required by applicable law.

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

Compensation Risk Assessment

The Compensation Committee reviews the relationship between our risk management policies and compensation policies and practices each year and, for 2013, has concluded that we do not have any compensation policies or practices that expose us to excessive or unnecessary risks that are reasonably likely to have a material adverse effect on us. Because the Compensation Committee retains the sole discretion for determining the actual amount paid to executives pursuant to the annual cash incentive bonus program, the Compensation Committee is able to assess the actual behavior of our executives as it relates to risk-taking in awarding bonus amounts. In addition, the performance objectives applicable to our annual bonus program consist of a combination of six or more diverse company-wide and business unit goals, including commercial, operational and financial goals to support our business plan and priorities, which we believe lessens the potential incentive to focus on meeting certain short term goals at the expense of longer term risk. Further, our use of long-term equity incentive compensation with three year vesting and performance periods serves our executive compensation program's goal of aligning the interests of executives and unitholders, thereby reducing the incentives to unnecessary risk-taking.

Compensation Committee Report

In fulfilling its oversight responsibilities, the board of directors of our general partner has reviewed and discussed with management the Compensation Discussion and Analysis contained in this Annual Report on Form 10-K for the year ended December 31, 2013. Based on these reviews and discussions, the board of directors of our general partner recommended that the Compensation Discussion and Analysis be included in the Annual Report on Form 10-K for the year ended December 31, 2013 for filing with the SEC.

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

Rene R. Joyce
James W. Whalen
In Seon Hwang
Robert B. Evans
Barry R. Pearl
Joe Bob Perkins
William D. Sullivan
Ruth I. Dreessen

Executive Compensation Tables

Summary Compensation Table for 2013

The following Summary Compensation Table sets forth the compensation of our named executive officers for 2013, 2012 and 2011. Additional details regarding the applicable elements of compensation in the Summary Compensation Table are provided in the footnotes following the table.

Name and Principal Position	Year	Salary	Bonus (1)	Stock Awards ($)(2)	All Other Compensation (3)	Total
Joe Bob Perkins	2013	$ 517,500	$ 918,750	$ 1,012,070	$ 21,456	$ 2,469,776
Chief Executive Officer	2012	478,000	633,600	784,417	20,488	1,916,505
	2011	454,000	748,800	542,079	20,390	1,765,269
Matthew J. Meloy	2013	316,667	355,469	360,238	21,046	1,053,420
Senior Vice President, Chief	2012	268,333	283,594	290,776	20,274	862,977
Financial Officer and Treasurer	2011	228,125	235,000	160,859	19,997	643,981
Rene R. Joyce	2013	560,000	980,000	1,025,563	21,542	2,587,105
Executive Chairman of	2012	557,833	924,000	1,022,777	20,569	2,525,179
the Board of Directors	2011	529,000	1,094,000	979,380	20,520	2,622,900
James W. Whalen	2013	480,000	672,000	661,608	21,379	1,834,987
Advisor to Chairman and CEO	2012	478,000	633,600	659,793	20,488	1,791,881
	2011	454,000	748,800	542,079	20,390	1,765,269
Michael A. Heim	2013	480,833	679,000	888,231	21,381	2,069,445
President and Chief Operating Officer	2012	452,500	607,200	685,357	20,462	1,765,519
	2011	403,500	664,000	480,517	20,302	1,568,319

(1) For 2013, represents payments pursuant to our 2013 Bonus Plan. Please see "—Components of Executive Compensation Program for Fiscal 2013—Annual Cash Incentive Bonus." As discussed above, payments pursuant to our Bonus Plan are discretionary and not based on objective performance measures.

(2) Amounts reported in the "Stock Awards" column represent the aggregate grant date fair value of restricted stock awards under our Stock Incentive Plan and of equity-settled performance unit awards under the Partnership's Long-Term Incentive Plan, in each case, granted in 2013 and computed in accordance with FASB ASC Topic 718. Assumptions used in the calculation of these amounts are included in Note 22 to our "Consolidated Financial Statements" beginning on page F-1 of our Annual Report on Form 10-K for fiscal year 2013. Detailed information about the amount recognized for specific awards is reported in the table under "—Grants of Plan-Based Awards for 2013" below. The grant date fair value of each restricted share subject to the restricted stock awards granted on January 15, 2013, assuming vesting will occur, is $57.015. The aggregate grant date fair value for the equity-settled performance unit awards granted on January 15, 2013 is determined by multiplying a number of units equal to approximately 87% of the number of performance units awarded by $40.30, and is consistent with the estimate of aggregate compensation cost to be recognized over the service period of the awards, excluding the effect of estimated forfeitures. Assuming, instead, a payout percentage for these performance unit awards of 150%, which is the maximum payout percentage under the awards, the aggregate grant date fair value of the equity-settled performance unit awards granted on January 15, 2013 for each named executive officer is as follows: Mr. Joyce - $1,284,623; Mr. Meloy - $451,259; Mr. Perkins - $1,267,697; Mr. Whalen - $828,709; and Mr. Heim - $1,112,582.

(3) For 2013 "All Other Compensation" includes (i) the aggregate value of all employer-provided contributions to our 401(k) plan and (ii) the dollar value of life insurance premiums paid by the Company with respect to life insurance for the benefit of each named executive officer.

Name	401(k) and Profit Sharing Plan	Dollar Value of Life Insurance	Total
Joe Bob Perkins	$ 20,400	$ 1,056	$ 21,456
Matthew J. Meloy	20,400	646	21,046
Rene R. Joyce	20,400	1,142	21,542
James W. Whalen	20,400	979	21,379
Michael A. Heim	20,400	981	21,381

Grants of Plan Based Awards for 2013

The following table and the footnotes thereto provide information regarding grants of plan-based equity awards made to the named executive officers during 2013:

		Estimated Future Payouts Under Equity Incentive Plan Awards (#) (1)				
Name	Grant Date	Threshold (#)	Target (#)	Maximum (#)	All Other Stock Awards: Number of Shares of Stock or Units (1)	Grant Date Fair Value of Equity Awards (2)
Mr. Perkins	1/15/2013				4,895	$ 279,088
	1/15/2013	7,487	20,971	31,457		732,982
Mr. Meloy	1/15/2013				1,742	99,320
	1/15/2013	2,665	7,465	11,198		260,918
Mr. Joyce	1/15/2013				4,960	282,794
	1/15/2013	7,587	21,251	31,877		742,769
Mr. Whalen	1/15/2013				3,200	182,448
	1/15/2013	4,894	13,709	20,564		479,160
Mr. Heim	1/15/2013				4,296	244,936
	1/15/2013	6,571	18,405	27,608		643,295

(1) The grants on January 15, 2013 are restricted stock awards granted under our Stock Incentive Plan and equity-settled performance units granted under the Partnership's Long-Term Incentive Plan. For a detailed description of how performance achievements will be determined for the equity-settled performance units, see "—Components of Executive Compensation Program for Fiscal 2013—Long-Term Equity Incentive Awards—Equity-Settled Performance Unit Awards."

(2) The dollar amounts shown for the restricted stock awards granted on January 15, 2013 are determined by multiplying the shares reported in the table by $57.015, which is the grant date fair value of awards computed in accordance with FASB ASC Topic 718. The dollar amounts shown for the equity-settled performance units granted on January 15, 2013 are determined by multiplying a number of units equal to approximately 87% of the number of units reported in the table under the "Target" column by $40.30, which is the grant date fair value of awards computed in accordance with FASB ASC Topic 718 and is consistent with the estimate of aggregate compensation cost to be recognized over the service period of the awards, excluding the effect of estimated forfeitures.

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

A discussion of 2013 salaries, bonuses, incentive plans and awards is set forth in "—Compensation Discussion and Analysis," including a discussion of the material terms and conditions of the 2013 restricted stock awards under our Stock Incentive Plan and the 2013 equity-settled performance unit awards under the Partnership's Long-Term Incentive Plan, such as the vesting schedule of such awards, any applicable performance-based conditions, and the extent to which dividends and distributions are paid with respect to such awards.

Outstanding Equity Awards at 2013 Fiscal Year-End

The following table and the footnotes related thereto provide information regarding equity-based awards outstanding as of December 31, 2013 for each of our named executive officers.

	Stock Awards			
Name	**Number of Shares of Stock That Have Not Vested (1)**	**Market Value of Shares of Stock That Have Not Vested (2)**	**Equity Incentive Plan Awards: Number of Unearned Units That Have Not Vested (3)**	**Equity Incentive Plan Awards: Market or Payout Value of Unearned Units That Have Not Vested (4)**
Joe Bob Perkins	14,180	$ 1,250,251	65,940	$ 3,448,662
Matthew J. Meloy	4,868	429,212	22,796	1,192,231
Rene R. Joyce	19,215	1,694,187	87,815	4,592,725
James W. Whalen	11,685	1,030,266	53,757	2,811,491
Michael A. Heim	12,465	1,099,039	57,927	3,029,582

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

	February 14, 2011 Award (a)	**January 12, 2012 Award (b)**	**January 15, 2013 Award (c)**	**Total**
Joe Bob Perkins	4,250	5,035	4,895	14,180
Matthew J. Meloy	1,260	1,866	1,742	4,868
Rene R. Joyce	7,690	6,565	4,960	19,215
James W. Whalen	4,250	4,235	3,200	11,685
Michael A. Heim	3,770	4,399	4,296	12,465

(a) The restricted shares subject to the February 14, 2011 awards are subject to the following vesting schedule: 100% of the restricted shares vest on February 14, 2014, contingent upon continuous employment at the end of the vesting period.

(b) The restricted shares subject to the January 12, 2012 awards are subject to the following vesting schedule: 100% of the restricted shares vest on January 12, 2015, contingent upon continuous employment at the end of the vesting period.

(c) The restricted shares subject to the January 15, 2013 awards are subject to the following vesting schedule: 100% of the restricted shares vest on January 15, 2016, contingent upon continuous employment at the end of the vesting period.

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

(2) The dollar amounts shown are determined by multiplying the number of shares of restricted stock reported in the table by the closing price of a share of our common stock on December 31, 2013 ($88.17). The amounts do not include any related dividends accrued with respect to the awards.

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

	February 17, 2011 Award (a)	**January 12, 2012 Award (b)**	**January 15, 2013 Award (c)**	**Total**
Joe Bob Perkins	17,535	24,435	23,970	65,940
Matthew J. Meloy	5,206	9,059	8,532	22,796
Rene R. Joyce	31,665	31,860	24,290	87,815
James W. Whalen	17,535	20,553	15,669	53,757
Michael A. Heim	15,540	21,350	21,037	57,927

(a) Reflects the target number of performance units granted to the named executive officers on February 17, 2011 multiplied by a performance percentage of 150%, which is the performance level under the award and in accordance with SEC rules is the next higher performance measure that exceeds 2013 performance. Vesting of these awards is contingent upon continuous employment at the end of the performance period, which ends June 30, 2014, and the Partnership's performance over the applicable performance period measured against a peer group of companies.

(b) Reflects the target number of performance units granted to the named executive officers on January 12, 2012 multiplied by a performance percentage of 150%, which is the maximum performance level under the award that would have been attained based on 2013 performance. Vesting of these awards is contingent upon continuous employment at the end of the performance period, which ends June 30, 2015, and the Partnership's performance over the applicable performance period measured against a peer group of companies.

(c) Reflects the target number of performance units granted to the named executive officers on January 15, 2013 multiplied by a performance percentage of 114.3%, which in accordance with SEC rules is the next higher performance measure that exceeds 2013 performance. Vesting of these awards is contingent upon continuous employment at the end of the performance period, which ends June 30, 2016, and the Partnership's performance over the applicable performance period measured against a peer group of companies.

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

(4) The dollar amounts shown are determined by multiplying the number of performance units reported in the table by the closing price of a common unit of the Partnership on December 31, 2013 ($52.30). The amounts do not include any related cash distributions accrued with respect to the awards.

Option Exercises and Stock Vested in 2013

The following table provides the amount realized during 2013 by each named executive officer upon the vesting of restricted stock and performance unit awards. None of our named executive officers exercised any option awards during the 2013 year and, currently, there are no options outstanding under any of our plans.

	Stock Vested for 2013		Units Vested for 2013	
Name	**Number of Shares Acquired on Vesting (1)**	**Value Realized on Vesting (2)**	**Number of Units Acquired on Vesting (3)**	**Value Realized on Vesting (4)**
Joe Bob Perkins	27,192	$ 2,148,440	19,806	$ 999,210
Matthew J. Meloy	8,970	708,720	5,716	288,372
Rene R. Joyce	48,450	3,828,035	25,758	1,299,477
James W. Whalen	27,192	2,148,440	19,240	970,661
Michael A. Heim	24,354	1,924,210	14,139	713,289

(1) Shares of restricted stock granted under our Stock Incentive Plan on December 10, 2010, which vested on December 10, 2013 (40% of the total number of restricted shares subject to each grant).
(2) Computed with respect to the restricted stock awards granted under our Stock Incentive Plan by multiplying the number of shares of stock vesting by the closing price of a share of common stock on the December 10, 2013 vesting date ($79.01) and does not include associated dividends accrued during the vesting period.
(3) Performance units linked to the performance of the Partnership's common units granted under the Partnership's Long-Term Incentive Plan in December 2009 (in August 2010 with respect to Mr. Meloy), which vested on June 30, 2013, at the 142.9% payout level
(4) Computed as the number of performance units vested multiplied by the closing price of a Partnership common unit on June 28, 2013 ($50.45), the last trading day preceding June 30, 2013 since the June 30, 2013 vesting date was not a trading day, and does not include associated distributions accrued during the vesting period.

Pension Benefits

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

Non-Qualified Deferred Compensation

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

Potential Payments Upon Termination or Change in Control

Aggregate Payments

The table below reflects the aggregate amount of payments and benefits that we believe our named executive officers would have received under our Executive Officer Change in Control Severance Program (the "Change in Control Program"), our Stock Incentive Plan and the Partnership's Long-Term Incentive Plan upon certain specified termination of employment and/or a change in control events, in each case, had such event occurred on December 31, 2013. Details regarding individual plans and arrangements follow the table. The amounts below constitute estimates of the amounts that would be paid to our named executive officers upon each designated event, and do not include any amounts accrued through fiscal 2013 year-end that would be paid in the normal course of continued employment, such as accrued but unpaid salary and benefits generally available to all salaried employees. The actual amounts to be paid are dependent on various factors, which may or may not exist at the time a named executive officer is actually terminated and/or a change in control actually occurs. Therefore, such amounts and disclosures should be considered "forward-looking statements."

Name	Change in Control (No Termination)	Qualifying Termination Following Change in Control	Termination by us without Cause	Termination for Death or Disability
Joe Bob Perkins	$ 4,029,328	$ 7,229,857	$ 4,007,045	$ 5,302,530
Matthew J. Meloy	1,390,497	2,903,526	1,385,803	1,830,232
Rene R. Joyce	5,341,977	8,739,994	5,329,864	7,089,653
James W. Whalen	3,266,916	5,896,933	3,263,960	4,333,388
Michael A. Heim	3,540,489	6,210,018	3,520,031	4,658,883

Executive Officer Change in Control Severance Program

We adopted the Executive Officer Change in Control Program, referred to herein as the Change in Control Program, on and effective as of January 12, 2012. Each of our named executive officers was an eligible participant in the Change in Control Program during the 2013 calendar year.

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

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

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

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

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

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

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

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

The following table reflects payments that would have been made to each of the named executive officers under the Change in Control Program in the event there was a Change in Control and the officer incurred a Qualifying Termination, in each case, as of December 31, 2013.

Name	Qualifying Termination Following Change in Control (1)
Joe Bob Perkins	$ 3,200,529
Matthew J. Meloy	1,513,029
Rene R. Joyce	3,398,017
James W. Whalen	2,630,017
Michael A. Heim	2,669,529

(1) Includes 3 years' worth of continued participation in our medical and dental plans, calculated based on the monthly employer-paid portion of the premiums for our medical and dental plans as of December 31, 2013 for each named executive officer and his eligible dependents in the following amounts: (a) Mr. Perkins – $50,529, (b) Mr. Meloy – $50,529, (c) Mr. Joyce – $38,017, (d) Mr. Whalen – $38,017, and (e) Mr. Heim – $50,529.

Stock Incentive Plan

Each of our named executive officers held outstanding restricted stock awards under our form of restricted stock agreement (the "Stock Agreement") and the Stock Incentive Plan as of December 31, 2013. If a "Change in Control" occurs and the named executive officer has (i) remained continuously employed by us from the date of grant to the date upon which such Change in Control occurs or (ii) retired following the date of grant and either performed consulting services for us or refrained from working for one of our competitors or in a similar role for another company, through the date of the Change in Control, then, in either case, the restricted stock granted to him under the Stock Agreements, and related dividends then credited to him, will fully vest on the date upon which such Change in Control occurs.

Restricted stock granted to a named executive officer under the Stock Agreements, and related dividends then credited to him, will also fully vest if the named executive officer's employment is terminated by reason of death or a "Disability". If a named executive officer's employment with us is terminated for any reason other than death or Disability, then his unvested restricted stock is forfeited to us for no consideration, except that, if a named executive officer retires, his awards will continue to vest on the third anniversary of the date of grant if, from the date of his retirement through the third anniversary date, the named executive officer has either performed consulting services for us or refrained from working for one of our competitors or in a similar role for another company.

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

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

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

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

The following table reflects amounts that would have been received by each of the named executive officers under the Stock Incentive Plan and related Stock Agreements in the event there was a Change in Control or their employment was terminated due to death or Disability, each as of December 31, 2013. The amounts reported below assume that the price per share of our common stock was $88.17, which was the closing price per share of our common stock on December 31, 2013. No amounts are reported assuming retirement as of December 31, 2013, since additional conditions must be met following a named executive officer's retirement in order for any restricted stock awards to become vested.

Name	Change in Control		Termination for Death or Disability	
Joe Bob Perkins	$ 1,295,485	(1)	$ 1,295,485	(1)
Matthew J. Meloy	444,429	(2)	444,429	(2)
Rene R. Joyce	1,759,789	(3)	1,759,789	(3)
James W. Whalen	1,069,428	(4)	1,069,428	(4)
Michael A. Heim	1,138,852	(5)	1,138,852	(5)

(1) Of the amount reported under each of the "Change in Control" column and the "Termination for Death or Disability" column: (a) $374,723 and $18,880, respectively, relate to the restricted shares and related dividend rights granted on February 14, 2011, which are scheduled to vest February 14, 2014; (b) $443,936 and $16,295, respectively, relate to the restricted shares and related dividend rights granted on January 12, 2012, which are scheduled to vest on January 12, 2015 and (c) $431,592 and $10,059, respectively, relate to the restricted shares and related dividend rights granted on January 15, 2013, which are scheduled to vest January 15, 2016.

(2) Of the amount reported under each of the "Change in Control" column and the "Termination for Death or Disability" column: (a) $111,094 and $5,598, respectively, relate to the restricted shares and related dividend rights granted on February 14, 2011, which are scheduled to vest February 14, 2014; (b) $164,525 and $6,039, respectively, relate to the restricted shares and related dividend rights granted on January 12, 2012, which are scheduled to vest on January 12, 2015; and (c) $153,592 and $3,580, respectively, relate to the restricted shares and related dividend rights granted on January 15, 2013, which are scheduled to vest January 15, 2016.

(3) Of the amount reported under each of the "Change in Control" column and the "Termination for Death or Disability" column: (a) $678,027 and $34,163, respectively, relate to the restricted shares and related dividend rights granted on February 14, 2011, which are scheduled to vest February 14, 2014; (b) $578,836 and $21,246, respectively, relate to the restricted shares and related dividend rights granted on January 12, 2012, which are scheduled to vest on January 12, 2015; and (c) $437,323 and $10,193, respectively, relate to the restricted shares and related dividend rights granted on January 15, 2013, which are scheduled to vest January 15, 2016.

(4) Of the amount reported under each of the "Change in Control" column and the "Termination for Death or Disability" column: (a) $374,723 and $18,880, respectively, relate to the restricted shares and related dividend rights granted on February 14, 2011, which are scheduled to vest February 14, 2014; (b) $373,400 and $13,706, respectively, relate to the restricted shares and related dividend rights granted on January 12, 2012, which are scheduled to vest on January 12, 2015; and (c) $282,144 and $6,576, respectively, relate to the restricted shares and related dividend rights granted on January 15, 2013, which are scheduled to vest January 15, 2016.

(5) Of the amount reported under each of the "Change in Control" column and the "Termination for Death or Disability" column: (a) $332,401 and $16,748, respectively, relate to the restricted shares and related dividend rights granted on February 14, 2011, which are scheduled to vest February 14, 2014; (b) $387,860 and $14,236, respectively, relate to the restricted shares and related dividend rights granted on January 12, 2012, which are scheduled to vest on January 12, 2015; and (c) $378,778 and $8,829, respectively, relate to the restricted shares and related dividend rights granted on January 15, 2013, which are scheduled to vest January 15, 2016.

Partnership's Long-Term Incentive Plan

Each of our named executive officers held outstanding performance unit awards under the Partnership's form of performance unit grant agreement (the "Performance Unit Agreement") and the Partnership's Long-Term Incentive Plan as of December 31, 2013. If a "Change in Control" occurs during the performance period established for the performance units and related distribution rights granted to a named executive officer under the Performance Unit Agreements, the performance units will be settled upon the occurrence of the Change in Control by providing the named executive officer with a number of common units of the Partnership equal to the target number of performance units granted to the named executive officer plus a cash payment in the amount of distribution equivalent rights then credited to the named executive officer, if any. The general partner may elect to settle the performance unit awards in cash instead of in common units.

Generally, performance units and the related distribution equivalent rights granted to a named executive officer under a Performance Unit Agreement will be automatically forfeited without payment upon the termination of the named executive officer's employment with us and our affiliates. However, if a named executive officer's employment is terminated by reason of his death or "Disability" or is terminated by us other than for "Cause," or if the executive has retired and he has either performed consulting services for us or refrained from working for one of our competitors or in a similar role for another company, through the end of the performance period, he will become vested in the performance units that he is otherwise qualified to receive payment for based on achievement of the performance goal at the end of the performance period as if the named executive officer had remained continuously employed through the end of the performance period. The named executive officer will also receive a cash payment in the amount of the distribution equivalent rights that would have accrued through the end of the performance period.

The following terms generally have the meanings specified below for purposes of the Partnership's Long-Term Incentive Plan:

- *Change in Control* means (i) any person or group, other than an affiliate, becomes the beneficial owner, by way of merger, consolidation, recapitalization, reorganization or otherwise, of 50% or more of the combined voting power of the equity interests in the Partnership or the general partner, (ii) the limited partners of the Partnership approve a plan of complete liquidation of the Partnership, (iii) the sale or other disposition by either the Partnership or the general partner of all or substantially all of its assets in one or more transactions to any person other than the general partner or one of the general partner's affiliates, or (iv) a transaction resulting in a person other than Targa Resources GP LLC or one of its affiliates being the general partner of the Partnership.

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

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

The following table reflects amounts that would have been received by each of the named executive officers under the Partnership's Long-Term Incentive Plan and related Performance Unit Agreements in the event there was a Change in Control (in which case the performance percentage is deemed to be 100%) or their employment was terminated due to death or Disability or by us without Cause, each as of December 31, 2013. No amounts are reported assuming retirement as of December 31, 2013, since additional conditions must be met following a named executive officer's retirement in order for any performance unit awards to become vested. The amounts reported below assume that the price per Partnership common unit was $52.30, which was the closing price per common unit on December 31, 2013. In addition, the amounts reported below in the "Termination for Death or Disability or Without Cause" column assume that the applicable performance period for each award ended December 31, 2013 and are based on achieving the next higher performance level for the award (if any) that exceeds performance for the 2013 fiscal year; however, the distribution amounts reported in this column are calculated through the end of the actual applicable performance period assuming the distribution level in effect as of December 31, 2013.

Name	Change in Control		Termination for Death or Disability or Without Cause	
Joe Bob Perkins	$ 2,733,843	(1)	$ 4,007,045	(1)
Matthew J. Meloy	946,068	(2)	1,385,803	(2)
Rene R. Joyce	3,582,188	(3)	5,329,864	(3)
James W. Whalen	2,197,488	(4)	3,263,960	(4)
Michael A. Heim	2,401,637	(5)	3,520,031	(5)

(1) Of the amount reported under the "Change in Control" column: (a) $611,387 and $76,073, respectively, relate to the performance units and related distribution equivalent rights granted on February 17, 2011; (b) $851,967 and $67,278, respectively, relate to the performance units and related distribution equivalent rights granted on January 12, 2012; and (c) $1,096,783 and $30,355, respectively, relate to the performance units and related distribution equivalent rights granted on January 15, 2013. Of the amount reported under the "Termination for Death or Disability or Without Cause" column: (a) $917,081 and $139,798, respectively, relate to the performance units and related distribution equivalent rights granted on February 17, 2011; (b) $1,277,951 and $208,308, respectively, relate to the performance units and related distribution equivalent rights granted on January 12, 2012; and (c) $1,253,630 and $210,277, respectively, relate to the performance units and related distribution equivalent rights granted on January 15, 2013.

(2) Of the amount reported under the "Change in Control" column: (a) $181,481 and $22,581, respectively, relate to the performance units and related distribution equivalent rights granted on February 17, 2011; (b) $315,840 and $24,941, respectively, relate to the performance units and related distribution equivalent rights granted on January 12, 2012; and (c) $390,420 and $10,805, respectively, relate to the performance units and related distribution equivalent rights granted on January 15, 2013. Of the amount reported under the "Termination for Death or Disability or Without Cause" column: (a) $272,222 and $41,497, respectively, relate to the performance units and related distribution equivalent rights granted on February 17, 2011; (b) $473,786 and $77,228, respectively, relate to the performance units and related distribution equivalent rights granted on January 12, 2012; and (c) $446,223 and $74,847, respectively, relate to the performance units and related distribution equivalent rights granted on January 15, 2013.

(3) Of the amount reported under each of the "Change in Control" column: (a) $1,104,053 and $137,373, respectively, relate to the performance units and related distribution equivalent rights granted on February 17, 2011; (b) $1,110,852 and $87,721, respectively, relate to the performance units and related distribution equivalent rights granted on January 12, 2012; and (c) $1,111,427 and $30,762, respectively, relate to the performance units and related distribution equivalent rights granted on January 15, 2013. Of the amount reported under the "Termination for Death or Disability or Without Cause" column: (a) $1,656,080 and $252,449, respectively, relate to the performance units and related distribution equivalent rights granted on February 17, 2011; (b) $1,666,278 and $271,607, respectively, relate to the performance units and related distribution equivalent rights granted on January 12, 2012; and (c) $1,270,366 and $213,084, respectively, relate to the performance units and related distribution equivalent rights granted on January 15, 2013.

(4) Of the amount reported under the "Change in Control" column: (a) $611,387 and $76,073, respectively, relate to the performance units and related distribution equivalent rights granted on February 17, 2011; (b) $716,615 and $56,589, respectively, relate to the performance units and related distribution equivalent rights granted on January 12, 2012; and (c) $716,981 and $19,843, respectively, relate to the performance units and related distribution equivalent rights granted on January 15, 2013. Of the amount reported under the "Termination for Death or Disability or Without Cause" column: (a) $917,081 and $139,798, respectively, relate to the performance units and related distribution equivalent rights granted on February 17, 2011; (b) $1,074,922 and $175,214, respectively, relate to the performance units and related distribution equivalent rights granted on January 12, 2012; and (c) $819,489 and $137,456, respectively, relate to the performance units and related distribution equivalent rights granted on January 15, 2013.

(5) Of the amount reported under the "Change in Control" column: (a) $541,828 and $67,418, respectively, relate to the performance units and related distribution equivalent rights granted on February 17, 2011; (b) $744,386 and $58,782, respectively, relate to the performance units and related distribution equivalent rights granted on January 12, 2012; and (c) $962,582 and $26,641, respectively, relate to the performance units and related distribution equivalent rights granted on January 15, 2013. Of the amount reported under the "Termination for Death or Disability or Without Cause" column: (a) $812,742 and $123,893, respectively, relate to the performance units and related distribution equivalent rights granted on February 17, 2011; (b) $1,116,605 and $182,009, respectively, relate to the performance units and related distribution equivalent rights granted on January 12, 2012; and (c) $1,100,235 and $184,547, respectively, relate to the performance units and related distribution equivalent rights granted on January 15, 2013.

Director Compensation

The following table sets forth the compensation earned by our non-employee directors for 2013:

Name	Director Compensation for 2013		
	Fees Earned or Paid in Cash	Stock Awards (4)	Total Compensation
Robert B. Evans (1)(2)	$ 71,000	$ 83,240	$ 154,240
Peter R. Kagan (1)(2)(3)	12,333	83,240	95,573
In Seon Hwang (1)(2)(3)	68,000	83,240	151,240
Barry R. Pearl (1)(2)	97,000	83,240	180,240
William D. Sullivan (1)(2)	77,000	83,240	160,240
Ruth I. Dreessen (1)(2)	69,333	86,372	155,705

(1) On January 15, 2013, each director received 2,130 common units of us in connection with their service on the Board of Directors of the General Partner. The grant date fair value of each common unit granted to each of these named individuals computed in accordance with FASB ASC Topic 718 was $39.08 for our common units, based on the average of the high and low price of the shares or common units on the date of grant.

(2) As of December 31, 2013, Mr. Evans held 32,396 common units, Mr. Kagan held 16,496 common units, Mr. Hwang held 6,246 common units, Mr. Pearl held 18,796 common units, Mr. Sullivan held 21,196 common units and Ms. Dreessen held 5,130 common units of us.

(3) Each of Messrs. Kagan and Hwang earned compensation for service on the Board of Directors of Targa in 2013 that is not included in the amounts reported above. Please see “Director Compensation” in Targa’s Annual Report on Form 10-K for the fiscal year ended December 31, 2013 for additional information

(4) Amounts represent the aggregate grant date fair value of awards computed in accordance with FASB ASC Topic 718. For a discussion of the assumptions and methodologies used to value the awards reported in this column, see the discussion of common unit and common stock awards contained in the Notes to Consolidated Financial Statements at Note 22 included in our Annual Report on Form 10-K for the year ended December 31, 2013.

Narrative to Director Compensation Table

For 2013, each of the General Partner’s independent directors received an annual cash retainer of $56,000. The Chairman of the General Partner’s Audit Committee received an additional annual retainer of $20,000. All of the General Partner’s independent directors receive $1,500 for each Board, Audit Committee and Conflicts Committee meeting attended. Payment of independent director fees is generally made twice annually, at the second regularly scheduled meeting of the General Partner’s Board and at the final regularly scheduled meeting of the General Partner’s Board for the fiscal year. All independent directors are reimbursed for out-of-pocket expenses incurred in attending General Partner’s Board and committee meetings.

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

Director Long-term Equity Incentives. The General Partner granted equity-based awards in January 2013 to the General Partner’s non-management and independent directors under the Long Term Incentive Plan. Each of these directors received an award of 2,130 common units of us, which reflected the General Partner’s intent to provide them with a target value of approximately $80,000 in annual long-term incentive awards. The awards are intended to align the long-term interests of the General Partner’s directors with those of our unitholders. The independent and non-management directors of the General Partner currently participate in our plan.

Changes for 2014

In January 2014, the General Partner’s Board approved changes to our independent director compensation for the 2014 fiscal year by increasing the annual cash retainer for service on the General Partner’s Board to $61,000 per year.

Director Long-term Equity Incentives. In January 2014, each of the General Partner's non-management and independent directors received an award of 1,748 fully vested common units under our long-term incentive plan, which reflects the General Partner's desire to increase the target value of those awards from approximately $80,000 to $90,000 per year.

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

The following table sets forth the beneficial ownership of our units and of Targa common stock, as applicable, as of February 10, 2014 (unless otherwise indicated) held by:

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

Beneficial ownership is determined under the rules of the Securities and Exchange Commission. In general, these rules attribute beneficial ownership of securities to persons who possess sole or shared voting power and/or investment power with respect to those securities and include, among other things, securities that an individual has the right to acquire within 60 days. Unless otherwise indicated, the unitholders identified in the table below have sole voting and investment power with respect to all units shown as beneficially owned by them. Percentage ownership calculations for any unitholder listed in the table below are based on 42,167,343 shares of Targa's common stock and 112,390,094 of our common units outstanding on February 10, 2014.

	Targa Resources Partners LP		Targa Resources Corp.	
Name of Beneficial Owner (1)	**Common Units Beneficially Owned** (2)	**Percentage of Common Units Beneficially Owned** (2)	**Common Stock Beneficially Owned**	**Percentage of Common Stock Beneficially Owned**
Targa Resources Corp.	12,945,659	11.5%	-	-
ClearBridge Advisors, LLC (3)	7,256,104	6.5%		
Rene R. Joyce (4)	81,000	*	1,090,361	2.6%
Joe Bob Perkins (5)	32,100	*	618,404	1.5%
Michael A. Heim (6)	8,000	*	599,172	1.4%
James W. Whalen (7)	111,152	*	635,472	1.5%
Matthew J Meloy	6,000	*	70,017	*
In Seon Hwang	7,994	*	-	-
Barry R. Pearl	20,544	*	-	-
Robert B. Evans	34,144	*	-	-
William D. Sullivan	22,944	*	-	-
Ruth I. Dreessen	6,878	*	-	-
All directors and executive officers as a group (14 persons)	398,756	*	4,630,766	11.0%

* Less than 1%

(1) Unless otherwise indicated, the address for all beneficial owners in this table is 1000 Louisiana, Suite 4300, Houston, Texas 77002 and the nature of the beneficial ownership for all the equity securities is sole voting and investment power.
(2) The common units presented as being beneficially owned by our directors and executive officers do not include the common units held indirectly by Targa Resources Corp. that may be attributable to such directors and officers based on their ownership of equity interests in Targa Resources Corp.
(3) As reported on Form 13F as of September 30, 2013 and filed with the SEC on November 14, 2013, the business address for Clearbridge Investments, LLC is 620 8th Avenue, New York, NY 10018.
(4) Shares of common stock beneficially owned by Mr. Joyce include: (i) 230,959 shares issued to The Rene Joyce 2010 Grantor Retained Annuity Trust, of which Mr. Joyce and his wife are co-trustees and have shared voting and investment power; and (ii) 561,292 shares issued to The Kay Joyce 2010 Family Trust, of which Mr. Joyce's wife is trustee and has sole voting and investment power.

(5) Shares of common stock beneficially owned by Mr. Perkins include 407,370 shares issued to the Perkins Blue House Investments Limited Partnership ("PBHILP"). Mr. Perkins is the sole member of JBP GP, L.L.C., one of the general partners of PBHILP.
(6) Shares of common stock beneficially owned by Mr. Heim include: (i) 187,378 shares issued to The Michael Heim 2009 Family Trust, of which Mr. Heim and his son are co-trustees and have shared voting and investment power; (ii) 116,672 shares issued to The Patricia Heim 2009 Grantor Retained Annuity Trust, of which Mr. Heim and his wife are co-trustees and have shared voting and investment power; (iii) 63,973 shares issued to the Pat Heim 2012 Family Trust, of which Mr. Heim's wife and son serve as co-trustees and have shared voting and investment power; (iv) 42,000 shares issued to the Heim 2012 Children's Trust, of which Mr. Heim serves as trustee; and (v) 21,972 shares held by Mr. Heim's wife of which Mr. Heim and his wife have shared voting and investment power.
(7) Shares of common stock beneficially owned by Mr. Whalen include 459,249 shares issued to the Whalen Family Investments Limited Partnership.

Securities Authorized for Issuance under Equity Compensation Plans

The following table sets forth certain information as of December 31, 2013 regarding our long-term incentive plan, called the Targa Resources Long-Term Incentive Plan (the "LTIP"), under which our common units are authorized for issuance to employees, consultants and directors who provide services to us. The LTIP is the sole equity compensation plan under which previously granted options, warrants or rights remain outstanding or under which we may make equity grants in the future. The LTIP was approved by our partners prior to our initial public offering.

Plan category	**Number of securities to be issued upon exercise of outstanding options, warrants and rights (1)**	**Weighted average exercise price of outstanding options, warrants and rights**	**Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))(2)**
	(a)	**(b)**	**(c)**
Equity compensation plans approved by security holders	552,198	-	1,014,692
Total	552,198	-	1,014,692

(1) Represents units subject to equity-settled performance unit awards granted under the LTIP, assuming the target distribution at the time of vesting. Payment with respect to the outstanding equity-settled performance unit awards may range from 0% to 150% of the target distribution depending on performance actually attained, with a maximum number of 828,297 units shown in column (a) being potentially issuable under the LTIP. There is no exercise price applicable to these awards.
(2) Includes units that may be issued in payment of the outstanding equity-settled performance unit awards reported in column (a) if and to the extent such payment exceeds the target distribution amount reported in column (a) with respect to such awards.

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

As of February 10, 2014, Targa owned 12,945,659 common units representing an aggregate 11.5% limited partner interest in us. In addition, our general partner owns a 2% general partner interest in us and the incentive distribution rights.

Distributions and Payments to Our General Partner and its Affiliates

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

Operational Stage	
Distributions of available cash to our general partner and its affiliates	We will generally make cash distributions 98% to our limited partner unitholders pro rata, including our general partner and its affiliates as the holders of 13,344,415 common units, and 2% to our general partner. In addition, if distributions exceed the minimum quarterly distribution and other higher target distribution levels, our general partner will be entitled to increasing percentages of the distributions, up to 50% of the distributions above the highest target distribution level. Assuming we have sufficient available cash to pay the full minimum quarterly distribution on all of our outstanding units for four quarters, our general partner and its affiliates would receive an annual distribution of approximately $3.1 million on their general partner units and $17.5 million on their common units.
Payments to our general partner and its affiliates	We reimburse Targa for the payment of certain operating expenses and for the provision of various general and administrative services for our benefit. See "Reimbursement of Operating and General and Administrative Expense."
Withdrawal or removal of our general partner	If our general partner withdraws or is removed, its general partner interest and its incentive distribution rights will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.
Liquidation Stage	
Liquidation	Upon our liquidation, the partners, including our general partner, will be entitled to receive liquidating distributions according to their respective capital account balances.

Partnership Agreement

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

Reimbursement of Operating and General and Administrative Expense

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

Competition

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

Indemnification Agreements

Indemnification Agreements with Targa

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

Indemnification Agreements with Directors and Officers

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

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

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

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

Transactions with Related Persons

Relationship with Laredo Petroleum Holdings Inc.

Peter Kagan, a former director of our general partner, is a Managing Director of Warburg Pincus LLC and is also a director of Laredo Petroleum Holdings Inc. ("Laredo") from whom we buy natural gas and NGL products. Affiliates of Warburg Pincus LLC own a controlling interest in Laredo. Purchases from Laredo during 2013 totaled $108.6 million. These transactions were at market prices consistent with similar transactions with other nonaffiliated entities.

Relationship with Sajet Resources LLC

Former holders of our pre-IPO common equity, including certain of our executive managers and directors, own a controlling interest in Sajet Resources LLC ("Sajet"), which was spun-off in December 2010 prior to the IPO. Sajet owns certain technology rights, real property and ownership interests in Allied CNG Ventures LLC. We provide general and administrative services to Sajet and are reimbursed for these amounts at our actual cost. During 2013, we were reimbursed $1.5 million for such services provided.

Relationship with Tesla Resources LLC

In September 2012, Tesla Resources LLC ("Tesla") was spun-off from Sajet. Tesla has ownership interests in Floridian Natural Gas Storage Company LLC ("Floridian"). We provide general and administrative services to Tesla and Floridian and is reimbursed for these amounts at our actual cost. During 2013, we were reimbursed $0.2 million for such services provided.

Relationship with Total Safety US Inc.

Joe Bob Perkins, Chief Executive Officer of our general partner, is also a member of the Board of Managers of W3 Holdings, LLC, parent company of Total Safety US Inc. ("Total Safety") which provides us safety services and equipment, including detection and monitoring systems. Affiliates of Warburg Pincus own a controlling interest in Total Safety. During 2013, we made payments of $0.3 million to Total Safety. These transactions were at market prices consistent with similar transactions with other nonaffiliated entities.

Relationships with Legacy Reserves LP and SM Energy Company

William D. Sullivan, a director of our general partner, is also a director of Legacy Reserves LP ("Legacy") and SM Energy Company ("SM Energy"). During 2013, we transacted purchases of $10.0 million with Legacy and $8.1 million with SM Energy. We also transacted sales of $25.7 million with Legacy during 2013. These transactions were at market prices consistent with similar transactions with other nonaffiliated entities.

Relationship with Magellan Asset Services LP

Barry Pearl, a director of our general partner, is also a director of Magellan Midstream Partners, L.P., parent company of Magellan Asset Services LP ("Magellan"). During 2013, we transacted sales of $31.0 million with Magellan. These transactions were at market prices consistent with similar transactions with other nonaffiliated entities.

Conflicts of Interest

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

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

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

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

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

Review, Approval or Ratification of Transactions with Related Persons

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

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

Director Independence

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

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

Item 14. Principal Accounting Fees and Services.

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

	2013	2012
	(In millions)	
Audit fees (1)	$ 2.5	$ 2.8
Audit related fees (2)	-	-
Tax fees (3)	-	-
All other fees (4)	-	-
	$ 2.5	$ 2.8

(1) Audit fees represent amounts billed for each of the years presented for professional services rendered in connection with (i) the integrated audit of our annual financial statements and internal control over financial reporting, (ii) the review of our quarterly financial statements or (iii) those services normally provided in connection with statutory and regulatory filings or engagements including comfort letters, consents and other services related to SEC matters. This information is presented as of the latest practicable date for this Annual Report.
(2) Audit-related fees represent amounts we were billed in each of the years presented for assurance and related services that are reasonably related to the performance of the annual audit or quarterly reviews of our financial statements and are not reported under audit fees.
(3) Tax fees represent amounts we were billed in each of the years presented for professional services rendered in connection with tax compliance, tax advice and tax planning.
(4) All other fees represent amounts we were billed in each of the years presented for services not classifiable under the other categories listed in the table above. No such services were rendered by PricewaterhouseCoopers LLP during the last two years.

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

PART IV

Item 15. Exhibits, Financial Statement Schedules.

(a)(1) Financial Statements

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

(a)(2) Financial Statement Schedules

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

(a)(3) Exhibits

Number	Description
2.1***	Purchase and Sale Agreement, dated September 18, 2007, by and between Targa Resources Holdings LP and Targa Resources Partners LP (incorporated by reference to Exhibit 2.1 to Targa Resources Partners LP's Current Report on Form 8-K filed September 21, 2007 (File No. 001-33303)).
2.2	Amendment to Purchase and Sale Agreement, dated October 1, 2007, by and between Targa Resources Holdings LP and Targa Resources Partners LP (incorporated by reference to Exhibit 2.2 to Targa Resources Partners LP's Current Report on Form 8-K filed October 24, 2007 (File No. 001-33303)).
2.3	Purchase and Sale Agreement dated July 27, 2009, by and between Targa Resources Partners LP, Targa GP Inc. and Targa LP Inc. (incorporated by reference to Exhibit 2.1 to Targa Resources Partners LP's Current Report on Form 8-K filed July 29, 2009 (File No. 001-33303)).
2.4	Purchase and Sale Agreement, dated March 31, 2010, by and among Targa Resources Partners LP, Targa LP Inc., Targa Permian GP LLC and Targa Midstream Holdings LLC (incorporated by reference to Exhibit 2.1 to Targa Resources Partners LP's Current Report on Form 8-K filed April 1, 2010(File No. 001-33303)).
2.5	Purchase and Sale Agreement, dated August 6, 2010, by and between Targa Resources Partners LP and Targa Versado Holdings LP (incorporated by reference to Exhibit 2.1 to Targa Resources Partners LP's Current Report on Form 8-K filed August 9, 2010 (File No. 001-33303)).
2.6	Purchase and Sale Agreement, dated September 13, 2010, by and between Targa Resources Partners LP and Targa Versado Holdings LP (incorporated by reference to Exhibit 2.1 to Targa Resources Partners LP's Current Report on Form 8-K filed September 17, 2010 (File No. 001-33303)).
2.7***	Membership Interest Purchase and Sale Agreement, dated November 14, 2012, by and among Targa Resources Partners LP, Saddle Butte Pipeline LLC, Saddle Butte Fort Berthold Gathering, LLC and Saddle Butte Assets, LLC (incorporated by reference to Exhibit 2.1 to Targa Resources Partners LP's Current Report on Form 8-K filed November 15, 2012 (File No. 001-33303)).
3.1	Certificate of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.2 to Targa Resources Partners LP's Registration Statement on Form S-1 filed November 16, 2006 (File No. 333-138747)).
3.2	Certificate of Formation of Targa Resources GP LLC (incorporated by reference to Exhibit 3.3 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed January 19, 2007 (File No. 333-138747)).

3.3	Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.3 to Targa Resources Partners LP’s Annual Report on Form 10-K filed April 2, 2007 (File No. 001-33303)).
3.4	First Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP (incorporated by reference to Exhibit 3.1 to Targa Resources Partners LP’s Current Report on Form 8-K filed February 16, 2007 (File No. 001-33303)).
3.5	Amendment No. 1 to First Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP, dated May 13, 2008, (incorporated by reference to Exhibit 3.5 to Targa Resources Partners LP’s Quarterly Report on Form 10-Q filed May 14, 2008 (File No. 001-33303)).
3.6	Amendment No. 2 to First Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP, dated May 25, 2012 (incorporated by reference to Exhibit 3.1 to Targa Resources Partners LP’s Current Report on Form 8-K filed May 25, 2012 (File No. 001-33303)).
3.7	Limited Liability Company Agreement of Targa Resources GP LLC (incorporated by reference to Exhibit 3.4 to Targa Resources Partners LP’s Registration Statement on Form S-1/A filed January 19, 2007 (File No. 333-138747)).
4.1	Specimen Unit Certificate representing common units (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP’s Annual Report on Form 10-K filed April 2, 2007 (File No. 001-33303)).
4.2	Indenture dated August 13, 2010 among the Issuers and the Guarantors and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP’s Current Report on Form 8-K filed August 16, 2010 (File No. 001-33303)).
4.3	Registration Rights Agreement dated August 13, 2010 among the Issuers, the Guarantors and Banc of America Securities LLC, as representative of the several initial purchasers (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP’s Current Report on Form 8-K filed August 16, 2010 (File No. 001-33303)).
4.4	Supplemental Indenture dated September 20, 2010 to Indenture dated August 13, 2010, among Targa Versado LP and Targa Versado GP LLC, subsidiaries of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.5 to Targa Resources Partners LP’s Quarterly Report on Form 10-Q filed November 5, 2010 (File No. 001-33303)).
4.5	Supplemental Indenture dated October 25, 2010 to Indenture dated August 13, 2010, among Targa Capital LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.8 to Targa Resources Partners LP’s Quarterly Report on Form 10-Q filed November 5, 2010 (File No. 001-33303)).
4.6	Supplemental Indenture dated April 8, 2011 to Indenture dated August 13, 2010, among Targa Terminals LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.6 to Targa Resources Partners LP’s Quarterly Report on Form 10-Q filed May 6, 2011 (File No. 001-33303)).
4.7	Supplemental Indenture dated October 28, 2011 to Indenture dated August 13, 2010, among Targa Gas Processing LLC, Targa Sound Terminal LLC and Sound Pipeline Company, LLC, subsidiaries of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP’s Quarterly Report on Form 10-Q filed November 7, 2011 (File No. 001-33303)).

4.8	Supplemental Indenture dated April 20, 2012 to Indenture dated August 13, 2010, among Targa Cogen LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed August 6, 2012 (File No. 001-33303)).
4.9	Supplemental Indenture dated February 14, 2013 to Indenture dated August 13, 2010, among Targa Badlands LLC, Targa Assets LLC and Targa Fort Berthold Gathering LLC, subsidiaries of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.60 to Targa Resources Partners LP's Annual Report on Form 10-K filed February 19, 2013 (File No. 001-33303)).
4.10	Indenture dated February 2, 2011 among the Issuers, the Guarantors and U.S. Bank National Association, as trustee thereto (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP's Current Report on Form 8-K filed February 2, 2011 (File No. 001-33303)).
4.11	Registration Rights Agreement dated February 2, 2011 among the Issuers, the Guarantors, Deutsche Bank Securities Inc., as representative of the several initial purchasers, and the Dealer Managers (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP's Current Report on Form 8-K filed February 3, 2011 (File No. 001-33303)).
4.12	Supplemental Indenture dated April 8, 2011 to Indenture dated February 2, 2011, among Targa Terminals LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.7 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed May 6, 2011 (File No. 001-33303)).
4.13	Supplemental Indenture dated October 28, 2011 to Indenture dated February 2, 2011, among Targa Gas Processing LLC, Targa Sound Terminal LLC and Sound Pipeline Company, LLC, subsidiaries of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.3 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed November 7, 2011 (File No. 001-33303)).
4.14	Supplemental Indenture dated April 20, 2012 to Indenture dated February 2, 2011, among Targa Cogen LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.3 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed August 6, 2012 (File No. 001-33303)).
4.15	Supplemental Indenture dated February 14, 2013 to Indenture dated February 2, 2011, among Targa Badlands LLC, Targa Assets LLC and Targa Fort Berthold Gathering LLC, subsidiaries of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.66 to Targa Resources Partners LP's Annual Report on Form 10-K filed February 19, 2013 (File No. 001-33303)).
4.16	Indenture dated as of January 31, 2012 among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors named therein and U.S. Bank National Association (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP's Current Report on Form 8-K filed January 31, 2012 (File No. 001-33303)).
4.17	Registration Rights Agreement dated as of January 31, 2012 among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors named therein and the initial purchasers named therein (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP's Current Report on Form 8-K filed January 31, 2012 (File No. 001-33303)).
4.18	Supplemental Indenture dated April 20, 2012 to Indenture dated January 31, 2012, among Targa Cogen LLC, a subsidiary of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.4 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed August 6, 2012 (File No. 001-33303)).

4.19	Supplemental Indenture dated February 14, 2013 to Indenture dated January 31, 2012, among Targa Badlands LLC, Targa Assets LLC and Targa Fort Berthold Gathering LLC, subsidiaries of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.70 to Targa Resources Partners LP's Annual Report on Form 10-K filed February 19, 2013 (File No. 001-33303)).
4.20	Indenture dated as of October 25, 2012 among Targa Resources Partners LP, Targa Resources Partners Finance Corporation and the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP's Current Report on Form 8-K filed October 26, 2012 (File No. 001-33303)).
4.21	Registration Rights Agreement dated as of October 25, 2012 among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors and Merrill Lynch, Pierce, Fenner & Smith Incorporated, Deutsche Bank Securities Inc., Wells Fargo Securities, LLC, Barclays Capital Inc. and RBS Securities Inc., as representatives of the several initial purchasers (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP's Current Report on Form 8-K filed October 26, 2012 (File No. 001-33303)).
4.22	Supplemental Indenture dated February 14, 2013 to Indenture dated October 25, 2012, among Targa Badlands LLC, Targa Assets LLC and Targa Fort Berthold Gathering LLC, subsidiaries of Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the other Subsidiary Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.73 to Targa Resources Partners LP's Annual Report on Form 10-K filed February 19, 2013 (File No. 001-33303)).
4.23	Registration Rights Agreement dated as of December 10, 2012 among the Issuers, the Guarantors and Merrill Lynch, Pierce, Fenner & Smith Incorporated, Deutsche Bank Securities Inc., Wells Fargo Securities, LLC, Barclays Capital Inc. and RBS Securities Inc., as representatives of the several initial purchasers. (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP's Current Report on Form 8-K filed December 10, 2012 (File No. 001-33303)).
4.24	Indenture dated as of May 14, 2013 among the Issuers and the Guarantors and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP's Current Report on Form 8-K filed May 14, 2012 (File No. 001-33303)).
4.25	Registration Rights Agreement dated as of May 14, 2013 among the Issuers, the Guarantors and Wells Fargo Securities, LLC, Barclays Capital Inc., Deutsche Bank Securities Inc., J.P. Morgan Securities LLC and RBC Capital Markets, LLC, as representatives of the several initial purchasers (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP's Current Report on Form 8-K filed May 14, 2012 (File No. 001-33303)).
10.1	Second Amended and Restated Credit Agreement, dated October 3, 2012, by and among Targa Resources Partners LP, Bank of America, N.A. and the other parties signatory thereto (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed October 9, 2012 (File No. 001-33303)).
10.2	Contribution, Conveyance and Assumption Agreement, dated February 14, 2007, by and among Targa Resources Partners LP, Targa Resources Operating LP, Targa Resources GP LLC, Targa Resources Operating GP LLC, Targa GP Inc., Targa LP Inc., Targa Regulated Holdings LLC, Targa North Texas GP LLC and Targa North Texas LP (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP's Current Report on Form 8-K filed February 16, 2007 (File No. 001-33303)).
10.3	Contribution, Conveyance and Assumption Agreement, dated October 24, 2007, by and among Targa Resources Partners LP, Targa Resources Holdings LP, Targa TX LLC, Targa TX PS LP, Targa LA LLC, Targa LA PS LP and Targa North Texas GP LLC (incorporated by reference to Exhibit 10.4 to Targa Resources Partners LP's Current Report on Form 8-K filed October 24, 2007 (File No. 001-33303)).

10.4	Contribution, Conveyance and Assumption Agreement, dated September 24, 2009, by and among Targa Resources Partners LP, Targa GP Inc., Targa LP Inc., Targa Resources Operating LP and Targa North Texas GP LLC (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed September 24, 2009 (File No. 001-33303)).
10.5	Contribution, Conveyance and Assumption Agreement, dated April 27, 2010, by and among Targa Resources Partners LP, Targa LP Inc., Targa Permian GP LLC, Targa Midstream Holdings LLC, Targa Resources Operating LP, Targa North Texas GP LLC and Targa Resources Texas GP LLC (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed April 29, 2010 (File No. 001-33303)).
10.6	Contribution, Conveyance and Assumption Agreement, dated August 25, 2010, by and among Targa Resources Partners LP, Targa Versado Holdings LP and Targa North Texas GP LLC (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed August 26, 2010 (File No. 001-33303)).
10.7	Contribution, Conveyance and Assumption Agreement, dated September 28, 2010, by and among Targa Resources Partners LP, Targa Versado Holdings LP and Targa North Texas GP LLC (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed October 4, 2010 (File No. 001-33303)).
10.8	Second Amended and Restated Omnibus Agreement, dated September 24, 2009, by and among Targa Resources Partners LP, Targa Resources, Inc., Targa Resources LLC and Targa Resources GP LLC (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP's Current Report on Form 8-K filed September 24, 2009 (file No. 001-33303)).
10.9	First Amendment to Second Amended and Restated Omnibus Agreement, dated April 27, 2010, by and among Targa Resources Partners LP, Targa Resources, Inc., Targa Resources LLC and Targa Resources GP LLC (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP's Current Report on Form 8-K filed April 29, 2010 (File No. 001-33303)).
10.10	Purchase Agreement dated as of October 22, 2012 among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors named therein and Merrill Lynch, Pierce, Fenner & Smith Incorporated, Deutsche Bank Securities Inc., Wells Fargo Securities, LLC, Barclays Capital Inc. and RBS Securities Inc., as representatives of the several initial purchasers (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed October 26, 2012 (File No. 001-33303)).
10.11	Purchase Agreement dated as of December 4, 2012 among the Issuers, the Guarantors and Merrill Lynch, Pierce, Fenner & Smith Incorporated, Deutsche Bank Securities Inc., Wells Fargo Securities, LLC, Barclays Capital Inc. and RBS Securities Inc., as representatives of the several initial purchasers (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed December 10, 2012 (File No. 001-33303)).
10.12	Purchase Agreement dated as of May 9, 2013 among the Issuers, the Guarantors and Wells Fargo Securities, LLC, Barclays Capital Inc., Deutsche Bank Securities Inc., J.P. Morgan Securities LLC and RBC Capital Markets, LLC, as representatives of the several initial purchasers (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed May 14, 2013 (File No. 001-33303)).
10.13	Receivables Purchase Agreement, dated January 10, 2013, by and among Targa Receivables LLC, the Partnership, as initial Servicer, the various conduit purchasers from time to time party thereto, the various committed purchasers from time to time party thereto, the various purchaser agents from time to time party thereto, the various LC participants from time to time party thereto and PNC Bank, National Association as Administrator and LC Bank (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed January 14, 2013 (File No. 001-33303)).

10.14	Second Amendment to Receivables Purchase Agreement, dated December 13, 2013, by and among Targa Receivables LLC, as seller, the Partnership, as servicer, the various conduit purchasers, committed purchasers, purchaser agents and LC participants party thereto and PNC Bank, National Association, as administrator and LC Bank (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed December 17, 2013 (File No. 001-33303)).
10.15	Purchase and Sale Agreement, dated January 10, 2013, between the originators from time to time party thereto as Originators and Targa Receivables LLC (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP's Current Report on Form 8-K filed January 14, 2013 (File No. 001-33303)).
10.16+	Targa Resources Investments Inc. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.9 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed February 1, 2007 (File No. 333-138747)).
10.17+	First Amendment to the Targa Resources Investments Inc. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to Targa Resources Partners LP's Current Report on Form 8-K/A filed July 24, 2013 (File No. 001-33303)).
10.18+	Form of Targa Resources Corp. 2010 Stock Incentive Plan (incorporated by reference to Exhibit 10.93 of Targa Investment's Inc.'s Registration Statement on Form S-1/A filed November 12, 2010 (File No. 333-169277)).
10.19+	Targa Resources Partners Long-Term Incentive Plan (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP's Registration Statement on Form S-1/A filed February 1, 2007 (File No. 333-138747)).
10.20+	Amendment to Targa Resources Partners LP Long-Term Incentive Plan dated December 18, 2008 (incorporated by reference to Exhibit 10.10 to Targa Resources Partners LP's Annual Report on Form 10-K filed February 27, 2009 (File No. 001-33303)).
10.21+	Form of Restricted Unit Grant Agreement - 2007 (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP's Current Report on Form 8-K filed February 13, 2007 (File No. 001-33303)).
10.22+	Form of Restricted Unit Grant Agreement – 2010 (incorporated by reference to Exhibit 10.15 to Targa Resources Partners LP's Annual Report on Form 10-K filed March 4, 2010 (File No. 001-33303)).
10.23+	Form of Performance Unit Grant Agreement – 2007 (incorporated by reference to Exhibit 10.3 to Targa Resources Partners LP's Current Report on Form 8-K filed with the SEC on February 13, 2007 (File No. 001-33303)).
10.24+	Form of Performance Unit Grant Agreement – 2008 (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP's Current Report on Form 8-K filed January 22, 2008 (File No. 001-33303)).
10.25+	Form of Performance Unit Grant Agreement – 2009 (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP's Current Report on Form 8-K filed January 28, 2009 (File No. 001-33303)).
10.26+	Form of Performance Unit Grant Agreement – 2010 (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP's Current Report on Form 8-K filed December 7, 2009 (File No. 001-33303)).
10.27+	Form of Performance Unit Grant Agreement – 2011 (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP's Current Report on Form 8-K filed February 18, 2011) (File No. 001-33303)).

10.28+	Targa Resources Partners LP Performance Unit Grant Agreement (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K/A filed July 24, 2013 (File No. 001-33303)).
10.29+	Targa Resources Partners LP Performance Unit Grant Agreement under the Targa Resources Corp. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.4 to Targa Resources Partners LP's Current Report on Form 8-K/A filed July 24, 2013 (File No. 001-33303)).
10.30+	Targa Resources Partners LP Amendment to Outstanding Performance Units (incorporated by reference to Exhibit 10.2 to Targa Resources Partners LP's Current Report on Form 8-K/A filed July 24, 2013 (File No. 001-33303)).
10.31+	Targa Resources Corp. Amendment to Targa Resources Partners LP Outstanding Performance Units (incorporated by reference to Exhibit 10.5 to Targa Resources Partners LP's Current Report on Form 8-K/A filed July 24, 2013 (File No. 001-33303)).
10.32+	Targa Resources Investments Inc. 2008 Annual Incentive Compensation Plan (incorporated by reference to Exhibit 10.13 to Targa Resources Partners LP’s Annual Report on Form 10-K filed February 27, 2009 (File No. 001-33303)).
10.33+	Targa Resources Investments Inc. 2009 Annual Incentive Compensation Plan (incorporated by reference to Exhibit 10.14 to Targa Resources Partners LP’s Annual Report on Form 10-K filed February 27, 2009 (File No. 001-33303)).
10.34+	Targa Resources Investments Inc. 2010 Annual Incentive Compensation Plan (incorporated by reference to Exhibit 10.22 to Targa Resources Partners LP’s Annual Report on Form 10-K filed March 4, 2010 (File No. 001-33303)).
10.35+	Targa Resources Corp. 2011 Annual Incentive Compensation Plan (incorporated by reference to Exhibit 10.27 to Targa Resources Partners LP’s Annual Report on Form 10-K filed February 28, 2011 (File No. 001-33303)).
10.36+	Targa Resources Corp. 2012 Annual Incentive Compensation Plan (incorporated by reference to Exhibit 10.31 to Targa Resources Partners LP’s Annual Report on Form 10-K filed February 27, 2012 (File No. 001-33303)).
10.37+	Targa Resources Corp. 2013 Annual Incentive Compensation Plan (incorporated by reference to Exhibit 10.3 to Targa Resources Partners LP’s Current Report on Form 8-K filed January 18, 2013 (File No. 001-33303)).
10.38+	Targa Resources Corp. 2014 Annual Incentive Compensation Plan (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP’s Current Report on Form 8-K filed January 21, 2014 (File No. 001-33303)).
10.39+	Targa Resources Executive Officer Change In Control Severance Program (incorporated by reference to Exhibit 10.3 to Targa Resources Partners LP’s Current Report on Form 8-K filed January 19, 2012 ((File No. 001-33303)).
10.40	Gas Gathering and Purchase Agreement by and between Burlington Resources Oil & Gas Company LP, Burlington Resources Trading Inc. and Targa Midstream Services Limited Partnership (portions of this exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a request for confidential treatment) (incorporated by reference to Exhibit 10.5 to Targa Resources Partners LP’s Registration Statement on Form S-1/A filed February 8, 2007 (File No. 333-138747)).

10.41	Form of Indemnification Agreement between Targa Resources Investments Inc. and each of the directors and officers thereof (incorporated by reference to Exhibit 10.4 to Targa Resources Corp.'s Registration Statement on Form S-1/A filed November 8, 2010 (File No. 333-169277)).
10.42+	Targa Resources Partners LP Indemnification Agreement for Robert B. Evans dated February 14, 2007 (incorporated by reference to Exhibit 10.11 to Targa Resources Partners LP's Annual Report on Form 10-K filed April 2, 2007 (File No. 001-33303)).
10.43+	Targa Resources Partners LP Indemnification Agreement for Barry R. Pearl dated February 14, 2007 (incorporated by reference to Exhibit 10.12 to Targa Resources Partners LP's Annual Report on Form 10-K filed April 2, 2007 (File No. 001-33303)).
10.44+	Targa Resources Partners LP Indemnification Agreement for William D. Sullivan dated February 14, 2007 (incorporated by reference to Exhibit 10.13 to Targa Resources Partners LP's Annual Report on Form 10-K filed April 2, 2007 (File No. 001-33303)).
10.45+	Targa Resources Partners LP Indemnification Agreement for Ruth I. Dreessen dated February 6, 2013 (incorporated by reference to Exhibit 10.44 to Targa Resources Partners LP's Annual Report on Form 10-K filed February 19, 2013 (File No. 001-33303)).
12.1*	Computation of Ratio of Earnings to Fixed Charges
21.1*	List of Subsidiaries of Targa Resources Partners LP.
23.1*	Consent of Independent Registered Public Accounting Firm.
31.1*	Certification of the Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.
31.2*	Certification of the Chief Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.
32.1**	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1***	First Amendment to Membership Interest Purchase and Sale Agreement, dated December 20, 2012, by and among the Partnership, Saddle Butte Pipeline LLC, Saddle Butte Fort Berthold Gathering, LLC and Saddle Butte Assets, LLC (incorporated by reference to Exhibit 99.1 to Targa Resources Partners LP's Current Report on Form 8-K filed January 4, 2013 (File No. 001-33303)).
101.INS**	XBRL Instance Document
101.SCH**	XBRL Taxonomy Extension Schema Document
101.CAL**	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF**	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB**	XBRL Taxonomy Extension Label Linkbase Document
101.PRE**	XBRL Taxonomy Extension Presentation Linkbase Document

* Filed herewith

**Furnished herewith

*** Pursuant to Item 601(b)(2) of Regulation S-K, the Partnership agrees to furnish supplementally a copy of any omitted exhibit or Schedule to the SEC upon request

+ Management contract or compensatory plan or arrangement

SIGNATURES

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

Targa Resources Partners LP
(Registrant)

By: Targa Resources GP LLC,
its general partner

Date: February 14, 2014

By: */s/ Matthew J. Meloy*
Matthew J. Meloy
Senior Vice President, Chief Financial Officer and Treasurer
(Authorized Officer and Principal Financial Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on February 14, 2014.

Signature	Title (Position with Targa Resources GP LLC)
/s/ Joe Bob Perkins Joe Bob Perkins	Chief Executive Officer and Director (Principal Executive Officer)
/s/ Matthew J. Meloy Mathew J. Meloy	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ John R. Sparger John R. Sparger	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)
/s/ Rene R. Joyce Rene R. Joyce	Executive Chairman of the Board
/s/ James W. Whalen James W. Whalen	Advisor to Chairman and CEO and Director
/s/ Barry R. Pearl Barry R. Pearl	Director
/s/ Robert B. Evans Robert B. Evans	Director
/s/ William D. Sullivan William D. Sullivan	Director
/s/ Ruth I. Dreessen Ruth I. Dreessen	Director

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

TARGA RESOURCES PARTNERS LP AUDITED CONSOLIDATED FINANCIAL STATEMENTS

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Targa Resources GP LLC, the general partner of Targa Resources Partners LP, is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

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

The management of Targa Resources GP LLC has used the framework set forth in the report entitled "Internal Control—Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") in 1992 to evaluate the effectiveness of our internal control over financial reporting. Based on that evaluation, management has concluded that our internal control over financial reporting was effective as of December 31, 2013.

The effectiveness of our internal control over financial reporting as of December 31, 2013 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears on page F-3.

/s/ Joe Bob Perkins
Joe Bob Perkins
Chief Executive Officer of Targa Resources GP LLC,
the general partner of Targa Resources Partners LP
(Principal Executive Officer)

/s/ Mathew J. Meloy
Matthew J. Meloy
Senior Vice President, Chief Financial Officer and Treasurer
of Targa Resources GP LLC, the general partner of
Targa Resources Partners LP
(Principal Financial Officer)

Report of Independent Registered Public Accounting Firm

To the Partners of Targa Resources Partners LP:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, of comprehensive income (loss), of changes in owners' equity and of cash flows present fairly, in all material respects, the financial position of Targa Resources Partners LP and its subsidiaries (the "Partnership") at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control - Integrated Framework* (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Partnership's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/PricewaterhouseCoopers LLP
Houston, Texas
February 14, 2014

PART I – FINANCIAL INFORMATION

Item 1. Financial Statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED BALANCE SHEETS

	December 31, 2013	December 31, 2012
	(In millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 57.5	$ 68.0
Trade receivables, net of allowances of $0.9 million and $0.7 million	658.6	514.9
Inventories	150.7	99.4
Assets from risk management activities	2.0	29.3
Other current assets	7.1	3.3
Total current assets	875.9	714.9
Property, plant and equipment	5,751.6	4,701.2
Accumulated depreciation	(1,406.2)	(1,168.0)
Property, plant and equipment, net	4,345.4	3,533.2
Intangible assets, net	653.4	680.8
Long-term assets from risk management activities	3.1	5.1
Investment in unconsolidated affiliate	55.9	53.1
Other long-term assets	37.7	38.6
Total assets	$ 5,971.4	$ 5,025.7
LIABILITIES AND OWNERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 721.2	$ 639.8
Accounts payable to Targa Resources Corp.	52.4	61.4
Liabilities from risk management activities	8.0	7.4
Total current liabilities	781.6	708.6
Long-term debt	2,905.3	2,393.3
Long-term liabilities from risk management activities	1.4	4.8
Deferred income taxes	12.1	11.2
Other long-term liabilities	52.6	47.7
Commitments and contingencies (see Note 16)		
Owners' equity:		
Common unitholders (111,263,207 and 100,095,989 units issued and outstanding as of December 31, 2013 and December 31, 2012)	2,001.9	1,649.5
General partner (2,270,680 and 2,042,776 units issued and outstanding as of December 31, 2013 and December 31, 2012)	62.0	45.3
Accumulated other comprehensive income (loss)	(6.1)	14.8
	2,057.8	1,709.6
Noncontrolling interests in subsidiaries	160.6	150.5
Total owners' equity	2,218.4	1,860.1
Total liabilities and owners' equity	$ 5,971.4	$ 5,025.7

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF OPERATIONS

	December 31,		
	2013	2012	2011
	(In millions, except per unit amounts)		
Revenues	$ 6,556.2	$ 5,883.6	$ 6,987.1
Costs and expenses:			
Product purchases	5,378.5	4,878.9	6,039.0
Operating expenses	376.2	313.0	287.0
Depreciation and amortization expenses	271.6	197.3	178.2
General and administrative expenses	143.1	131.6	127.8
Other operating expense	9.6	19.9	0.2
Income from operations	377.2	342.9	354.9
Other income (expense):			
Interest expense, net	(131.0)	(116.8)	(107.7)
Equity earnings	14.8	1.9	8.8
Loss on debt redemptions and amendments	(14.7)	(12.8)	-
Loss on mark-to-market derivative instruments	-	-	(5.0)
Other	15.2	(7.8)	(1.2)
Income before income taxes	261.5	207.4	249.8
Income tax expense:			
Current	(2.0)	(2.5)	(3.5)
Deferred	(0.9)	(1.7)	(0.8)
	(2.9)	(4.2)	(4.3)
Net income	258.6	203.2	245.5
Less: Net income attributable to noncontrolling interests	25.1	28.6	41.0
Net income attributable to Targa Resources Partners LP	$ 233.5	$ 174.6	$ 204.5
Net income attributable to general partner	$ 107.5	$ 66.7	$ 38.0
Net income attributable to limited partners	126.0	107.9	166.5
Net income attributable to Targa Resources Partners LP	$ 233.5	$ 174.6	$ 204.5
Net income per limited partner unit - basic	$ 1.19	$ 1.20	$ 1.98
Net income per limited partner unit - diluted	$ 1.19	$ 1.20	$ 1.98
Weighted average limited partner units outstanding - basic	105.5	90.1	84.1
Weighted average limited partner units outstanding - diluted	105.7	90.2	84.2

See notes to consolidated financial statements.

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

	2013	2012	2011
		(In millions)	
Net income	$ 258.6	$ 203.2	$ 245.5
Other comprehensive income (loss):			
Commodity hedging contracts:			
Change in fair value	(5.8)	76.4	(33.4)
Settlements reclassified to revenues	(21.2)	(43.9)	34.7
Interest rate swaps:			
Change in fair value	-	-	(4.4)
Settlements reclassified to interest expense, net	6.1	7.9	8.1
Other comprehensive income (loss)	$ (20.9)	$ 40.4	$ 5.0
Comprehensive income	237.7	243.6	250.5
Less: Comprehensive income attributable to noncontrolling interests	25.1	28.6	41.0
Comprehensive income attributable to Targa Resources Partners LP	$ 212.6	$ 215.0	$ 209.5

See notes to consolidated financial statements.

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

	Limited Partner Units	Limited Partner Amount	General Partner Units	General Partner Amount	Accumulated Other Comprehensive Income (Loss)	Non-controlling Interests	Total
	(In millions, except units in thousands)						
Balance December 31, 2010	75,545	$ 935.3	1,542	$ 15.1	$ (30.6)	$ 129.3	$ 1,049.1
Compensation on equity grants	11	1.5	-	-	-	-	1.5
Proceeds from equity offerings	9,200	297.8	188	6.3	-	-	304.1
Contributions from Targa Resources Corp.	-	11.5	-	1.7	-	-	13.2
Distributions to noncontrolling interests	-	-	-	-	-	(31.4)	(31.4)
Other comprehensive income	-	-	-	-	5.0	-	5.0
Net income	-	166.5	-	38.0	-	41.0	245.5
Distributions	-	(191.4)	-	(33.9)	-	-	(225.3)
Balance December 31, 2011	84,756	$ 1,221.2	1,730	$ 27.2	$ (25.6)	$ 138.9	$ 1,361.7
Compensation on equity grants	10	3.6	-	-	-	-	3.6
Accrual of distribution equivalent rights	-	(0.5)	-	-	-	-	(0.5)
Equity offerings	15,330	543.0	313	11.5	-	-	554.5
Distributions to noncontrolling interests	-	-	-	-	-	(20.2)	(20.2)
Contributions from noncontrolling interests	-	-	-	-	-	3.2	3.2
Other comprehensive income	-	-	-	-	40.4	-	40.4
Net income	-	107.9	-	66.7	-	28.6	203.2
Distributions	-	(225.7)	-	(60.1)	-	-	(285.8)
Balance December 31, 2012	100,096	$ 1,649.5	2,043	$ 45.3	$ 14.8	$ 150.5	$ 1,860.1
Compensation on equity grants	13	6.0	-	-	-	-	6.0
Accrual of distribution equivalent rights	-	(1.7)	-	-	-	-	(1.7)
Equity offerings	11,154	517.8	228	10.8	-	-	528.6
Distributions to noncontrolling interests	-	-	-	-	-	(19.3)	(19.3)
Contributions from noncontrolling interests	-	-	-	-	-	4.3	4.3
Other comprehensive loss	-	-	-	-	(20.9)	-	(20.9)
Net income	-	126.0	-	107.5	-	25.1	258.6
Distributions	-	(295.7)	-	(101.6)	-	-	(397.3)
Balance December 31, 2013	111,263	$ 2,001.9	2,271	$ 62.0	$ (6.1)	$ 160.6	$ 2,218.4

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2013	2012	2011
	(In millions)		
Cash flows from operating activities			
Net income	$ 258.6	$ 203.2	$ 245.5
Adjustments to reconcile net income to net cash provided by operating activities:			
Amortization in interest expense	15.5	17.6	12.4
Compensation on equity grants	6.0	3.6	1.5
Depreciation and amortization expense	271.6	197.3	178.2
Accretion of asset retirement obligations	3.9	3.9	3.6
Deferred income tax expense	0.9	1.7	0.8
Equity earnings, net of distributions	(2.8)	-	(0.4)
Risk management activities	(0.5)	5.3	(16.7)
Loss on sale or disposition of assets	3.9	15.6	0.2
Loss on debt redemptions and amendments	14.7	12.8	-
Changes in operating assets and liabilities:			
Receivables and other assets	(145.8)	90.2	(109.2)
Inventory	(84.5)	5.9	(41.1)
Accounts payable and other liabilities	69.9	(91.7)	126.1
Net cash provided by operating activities	411.4	465.4	400.9
Cash flows from investing activities			
Outlays for property, plant and equipment	(1,013.6)	(582.3)	(328.7)
Business acquisitions, net of cash acquired	-	(996.2)	(156.5)
Purchase of material and supplies	(17.7)	-	-
Investment in unconsolidated affiliate	-	(16.8)	(21.2)
Return of capital from unconsolidated affiliate	-	0.5	-
Other, net	5.0	1.0	0.3
Net cash used in investing activities	(1,026.3)	(1,593.8)	(506.1)
Cash flows from financing activities			
Proceeds from borrowings under credit facility	1,613.0	1,595.0	1,787.0
Repayments of credit facility	(1,838.0)	(1,473.0)	(2,054.3)
Issuance of senior notes	625.0	1,000.0	325.0
Borrowings from accounts receivable securitization facility	373.3	-	-
Repayments of accounts receivable securitization facility	(93.6)	-	-
Cash paid on note exchange	-	-	(27.7)
Redemption of senior notes	(183.2)	(217.7)	-
Costs incurred in connection with financing arrangements	(15.3)	(35.7)	(18.2)
Proceeds from equity offerings	535.5	575.0	316.1
Distributions	(397.3)	(285.7)	(225.2)
Contributions from parent	-	1.0	13.2
Contributions from noncontrolling interests	4.3	3.2	-
Distributions to noncontrolling interests	(19.3)	(21.3)	(31.4)
Net cash provided by financing activities	604.4	1,140.8	84.5
Net change in cash and cash equivalents	(10.5)	12.4	(20.7)
Cash and cash equivalents, beginning of period	68.0	55.6	76.3
Cash and cash equivalents, end of period	$ 57.5	$ 68.0	$ 55.6

See notes to consolidated financial statements.

TARGA RESOURCES PARTNERS LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

Note 1 — Organization and Operations

Our Organization

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

Targa Resources GP LLC is a Delaware limited liability company formed by Targa in October 2006 to own a 2% general partner interest in us. Its primary business purpose is to manage our affairs and operations. Targa Resources GP LLC is an indirect wholly owned subsidiary of Targa. As of December 31, 2013, Targa owned a 13.4% interest in us in the form of 2,270,680 general partner units and 12,945,659 common units. In addition, Targa Resources GP LLC also owns incentive distribution rights ("IDRs"), which entitle it to receive increasing cash distributions up to 48% of distributable cash for a quarter.

Allocation of costs

The employees supporting our operations are employed by Targa Resources LLC, a Delaware limited liability company and an indirect wholly owned subsidiary of Targa. Our financial statements include the direct costs of Targa employees deployed to our operating segments, as well as an allocation of costs associated with our usage of Targa centralized general and administrative services.

Our Operations

We are engaged in the business of gathering, compressing, treating, processing and selling natural gas; storing, fractionating, treating, transporting and selling NGLs and NGL products; gathering, storing and terminaling crude oil; and storing, terminaling and selling refined petroleum products. See Note 21 for certain financial information for our business segments.

Note 2 — Basis of Presentation

These accompanying financial statements and related notes present our consolidated financial position as of December 31, 2013 and 2012, and the results of operations, comprehensive income, cash flows and changes in owners' equity for the years ended December 31, 2013, 2012 and 2011.

We have prepared our consolidated financial statements in accordance with accounting principles generally accepted in the United States of America ("GAAP"). The consolidated financial results of our predecessors may not necessarily be indicative of the conditions that would have existed or the results of operations if our predecessors had been operated as unaffiliated entities. All significant intercompany balances and transactions have been eliminated. Certain amounts in prior periods have been reclassified to conform to the current year presentation.

Note 3 — Significant Accounting Policies

Consolidation Policy

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

We follow the equity method of accounting if our ownership interest is between 20% and 50% and we exercise significant influence over the operating and financial policies of the investee.

Cash and Cash Equivalents

Cash and cash equivalents include all cash on hand, demand deposits, and investments with original maturities of three months or less. We consider cash equivalents to include short-term, highly liquid investments that are readily convertible to known amounts of cash and which are subject to an insignificant risk of changes in value.

Comprehensive Income

Comprehensive income includes net income and other comprehensive income ("OCI"), which includes unrealized gains and losses on derivative instruments that are designated as hedges.

Allowance for Doubtful Accounts

Estimated losses on accounts receivable are provided through an allowance for doubtful accounts. In evaluating the adequacy of the allowance, we make judgments regarding each party's ability to make required payments, economic events and other factors. As the financial condition of any party changes, circumstances develop or additional information becomes available, adjustments to an allowance for doubtful accounts may be required.

Inventories

Our inventories consist primarily of NGL product inventories. Most NGL product inventories turn over monthly, but some inventory, primarily propane, is acquired and held during the year to meet anticipated heating season requirements of our customers. NGL product inventories are valued at the lower of cost or market using the average cost method. Commodity inventories that are not physically or contractually available for sale under normal operations ("deadstock") are classified as Property, Plant and Equipment. Inventories also include materials and supplies required for our Badlands expansion activities in North Dakota, which are valued using the specific identification method.

Product Exchanges

Exchanges of NGL products are executed to satisfy timing and logistical needs of the exchange parties. Volumes received and delivered under exchange agreements are recorded as inventory. If the locations of receipt and delivery are in different markets, a price differential may be billed or owed. The price differential is recorded as either accounts receivable or accrued liabilities.

Gas Processing Imbalances

Quantities of natural gas and/or NGLs over-delivered or under-delivered related to certain gas plant operational balancing agreements are recorded monthly as inventory or as a payable using the weighted average price at the time the imbalance was created. Inventory imbalances receivable are valued at the lower of cost or market; inventory imbalances payable are valued at replacement cost. These imbalances are settled either by current cash-out settlements or by adjusting future receipts or deliveries of natural gas or NGLs.

Derivative Instruments

We employ derivative instruments to manage the volatility of cash flows due to fluctuating energy prices and interest rates. All derivative instruments not qualifying for the normal purchase and normal sale exception are recorded on the balance sheets at fair value. The treatment of the periodic changes in fair value will depend on whether the derivative is designated and effective as a hedge for accounting purposes. We have designated certain liquids marketing contracts that meet the definition of a derivative as normal purchases and normal sales, which under GAAP, are not accounted for as derivatives.

If a derivative qualifies for hedge accounting and is designated as a cash flow hedge, the effective portion of the unrealized gain or loss on the derivative is deferred in Accumulated Other Comprehensive Income ("AOCI"), a component of owners' equity, and reclassified to earnings when the forecasted transaction occurs. Cash flows from a derivative instrument designated as a hedge are classified in the same category as the cash flows from the item being hedged. As such, we include the cash flows from commodity derivative instruments in revenues and from interest rate derivative instruments in interest expense.

If a derivative does not qualify as a hedge or is not designated as a hedge, the gain or loss on the derivative is recognized currently in earnings. The ultimate gain or loss on the derivative transaction upon settlement is also recognized as a component of other income and expense.

We formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives and strategy for undertaking the hedge. This documentation includes the specific identification of the hedging instrument and the hedged item, the nature of the risk being hedged and the manner in which the hedging instrument's effectiveness will be assessed. At the inception of the hedge, and on an ongoing basis, we assess whether the derivatives used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items.

The relationship between the hedging instrument and the hedged item must be highly effective in achieving the offset of changes in cash flows attributable to the hedged risk both at the inception of the contract and on an ongoing basis. We measure hedge ineffectiveness on a quarterly basis and reclassify any ineffective portion of the unrealized gain or loss to earnings in the current period.

We will discontinue hedge accounting on a prospective basis when a hedge instrument is terminated or ceases to be highly effective. Gains and losses deferred in AOCI related to cash flow hedges for which hedge accounting has been discontinued remain deferred until the forecasted transaction occurs. If it is no longer probable that a hedged forecasted transaction will occur, deferred gains or losses on the hedging instrument are reclassified to earnings immediately.

For balance sheet classification purposes, we analyze the fair values of the derivative contracts on a deal by deal basis.

Property, Plant and Equipment

Property, plant and equipment are stated at acquisition value less accumulated depreciation. All of our property, plant and equipment purchased from Targa from 2007 to 2010 in drop-down transactions were stated at historical cost in the transactions recorded under common control accounting. Depreciation is computed using the straight-line method over the estimated useful lives of the assets.

Expenditures for maintenance and repairs are expensed as incurred. Expenditures to refurbish assets that extend the useful lives or prevent environmental contamination are capitalized and depreciated over the remaining useful life of the asset or major asset component. We also capitalize certain costs directly related to the construction of assets, including internal labor costs, interest and engineering costs.

Our determination of the useful lives of property, plant and equipment requires us to make various assumptions, including the supply of and demand for hydrocarbons in the markets served by our assets, normal wear and tear of the facilities, and the extent and frequency of maintenance programs.

We evaluate the recoverability of our property, plant and equipment when events or circumstances such as economic obsolescence, the business climate, legal and other factors indicate we may not recover the carrying amount of the assets. Asset recoverability is measured by comparing the carrying value of the asset with the asset's expected future undiscounted cash flows. These cash flow estimates require us to make projections and assumptions for many years into the future for pricing, demand, competition, operating cost and other factors. If the carrying amount exceeds the expected future undiscounted cash flows we recognize an impairment loss to write down the carrying amount of the asset to its fair value as determined by quoted market prices in active markets or present value techniques if quotes are unavailable. The determination of the fair value using present value techniques requires us to make projections and assumptions regarding the probability of a range of outcomes and the rates of interest used in the present value calculations. Any changes we make to these projections and assumptions could result in significant revisions to our evaluation of recoverability of our property, plant and equipment and the recognition of an impairment loss in our consolidated statements of operations. Upon disposition or retirement of property, plant and equipment, any gain or loss is recorded to operations. See Note 6.

Intangible Assets

Intangible assets arose from producer dedications under long-term contracts and customer relationships associated with businesses acquisitions. The fair value of these acquired intangible assets was determined at the date of acquisition based on the present value of estimated future cash flows. Amortization expense attributable to these assets is recorded in a manner that closely resembles the expected pattern in which we benefit from services provided to customers. See Note 6.

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

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

Changes due to the passage of time increase the carrying amount of the liability because there are fewer periods remaining from the initial measurement date until the settlement date; therefore, the present values of the discounted future settlement amount increases. These changes are recorded as a period cost called accretion expense. Changes resulting from revisions to the timing or the amount of the original estimate of undiscounted cash flows shall be recognized as an increase or a decrease in the carrying amount of the liability for an asset retirement obligation and the related asset retirement cost capitalized as part of the carrying amount of the related long-lived asset. Upon settlement, AROs will be extinguished by us at either the recorded amount or we will recognize a gain or loss on the difference between the recorded amount and the actual settlement cost. See Note 7.

Debt Issue Costs

Costs incurred in connection with the issuance of long-term debt are deferred and charged to interest expense over the term of the related debt. Gains or losses on debt repurchases, redemptions and debt extinguishments include any associated unamortized debt issue costs.

Accounts Receivable Securitization Facility

Proceeds from the sale or contribution of certain receivables under our Accounts Receivable Securitization Facility (the “Securitization Facility”) are treated as collateralized borrowings in our financial statements. Such borrowings are reflected as long-term debt on our balance sheets to the extent that we have the ability and intent to fund the Securitization Facility’s borrowings on a long-term basis. Proceeds and repayments under the Securitization Facility are reflected as cash flows from financing activities on our statements of cash flows.

Environmental Liabilities and Other Loss Contingencies

Liabilities for loss contingencies, including environmental remediation costs arising from claims, assessments, litigation, fines, penalties and other sources are charged to expense when it is probable that a liability has been incurred and the amount of the loss can be reasonably estimated. See Note 16.

Income Taxes

We generally are not subject to federal income taxes. For federal income tax purposes, our earnings or losses are included in the tax returns of our separate partners. The taxable income or loss passed through to our partners may vary substantially from the net income or net loss we report in the consolidated statement of income. We are also subject to the Texas margin tax, consisting generally of a 1% tax on the amount by which total revenues exceed cost of goods sold, as apportioned to Texas.

Noncontrolling Interests

Third-party ownership in the net assets of our consolidated subsidiaries is shown as noncontrolling interests within the equity section of the balance sheet. In the statements of operations and statements of comprehensive income, noncontrolling interests reflects the allocation of results to third-party investors.

Revenue Recognition

Our operating revenues are primarily derived from the following activities:

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

We recognize revenues when all of the following criteria are met: (1) persuasive evidence of an exchange arrangement exists, if applicable, (2) delivery has occurred or services have been rendered, (3) the price is fixed or determinable and (4) collectability is reasonably assured.

For natural gas processing activities, we receive either fees or a percentage of commodities as payment for these services, depending on the type of contract. Under fee-based contracts, we receive a fee based on throughput volumes. Under percent-of-proceeds contracts, we receive either an agreed upon percentage of the actual proceeds that we receive from our sales of the residue natural gas and NGLs or an agreed upon percentage based on index related prices for the natural gas and NGLs. Percent-of-value and percent-of-liquids contracts are variations on this arrangement. Under keep-whole contracts, we retain the NGLs extracted and return the processed natural gas or value of the natural gas to the producer. A significant portion of our Straddle plant processing contracts are hybrid contracts under which settlements are made on a percent-of-liquids basis or a fee basis, depending on market conditions. Natural gas or NGLs that we receive for services or purchase for resale are in turn sold and recognized in accordance with the criteria outlined above.

We generally report sales revenues gross in our consolidated statements of operations, as we typically act as the principal in the transactions where we receive commodities, take title to the natural gas and NGLs, and incur the risks and rewards of ownership. However, buy-sell transactions with the same counterparty are reported on a net basis.

Unit-Based Compensation

We award unit-based compensation to employees, directors and non-management directors in the form of restricted common units and performance units. Compensation expense on restricted common units and performance unit awards that qualify as equity arrangements are measured by the fair value of the award as determined by the market at the date of grant. Compensation expense on performance unit awards that qualify as liability arrangements is initially measured by the fair value of the award at the date of grant, and re-measured subsequently at each reporting date through the settlement period. Compensation expense is recognized in general and administrative expense over the requisite service period of each award. See Note 20.

Earnings per Unit

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

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

Use of Estimates

When preparing financial statements in conformity with GAAP, management must make estimates and assumptions based on information available at the time. These estimates and assumptions affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosures of contingent assets and liabilities as of the date of the financial statements. Estimates and judgments are based on information available at the time such estimates and judgments are made. Adjustments made with respect to the use of these estimates and judgments often relate to information not previously available. Uncertainties with respect to such estimates and judgments are inherent in the preparation of financial statements. Estimates and judgments are used in, among other things, (1) estimating unbilled revenues, product purchases and operating and general and administrative costs, (2) developing fair value assumptions, including estimates of future cash flows and discount rates, (3) analyzing long-lived assets for possible impairment, (4) estimating the useful lives of assets and (5) determining amounts to accrue for contingencies, guarantees and indemnifications. Actual results, therefore, could differ materially from estimated amounts.

Recent Accounting Pronouncements

In January 2013, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2013-01, *Balance Sheet (Topic 210): Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities,* which clarifies that ASU No. 2011-11, *Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities,* applies to financial instruments or derivative transactions accounted for under ASC Topic 815. We currently present our derivative assets and liabilities on a gross basis on our statement of financial position. The amendments require disclosure of both gross and net amounts of derivative assets and liabilities that are subject to master netting arrangements with counterparties. We have provided these additional disclosures regarding the gross and net amounts of derivative assets and liabilities in Note 13.

In February 2013, the FASB issued ASU No. 2013-02, *Comprehensive Income (Topic 220): Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income*. The amendment, required to be applied prospectively for reporting periods beginning after December 15, 2012, requires entities to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line item of net income. Our financial statement presentation complies with this standards update.

Note 4 –Business Acquisitions

2012 Acquisition

Badlands

On December 31, 2012, we completed the acquisition of Saddle Butte Pipeline, LLC's ownership of its Williston Basin crude oil pipeline and terminal system and its natural gas gathering and processing operations (collectively "Badlands"), for cash consideration of $975.8 million, subject to a contingent payment.

The acquired business, located in the Bakken and Three Forks Shale plays of the Williston basin in North Dakota, expands our portfolio of midstream assets and diversifies our business with the addition of fee-based crude oil gathering and natural gas gathering and processing. The Badlands financial results are included in our Field Gathering and Processing business segment.

Pursuant to the Membership Interest Purchase and Sale Agreement ("MIPSA"), the acquisition is subject to a contingent payment of $50 million (the "contingent consideration") if aggregate crude oil gathering volumes exceed certain stipulated monthly thresholds during the period from January 2013 through June 2014. If the threshold is not attained during the contingency period, no payment is owed. Accounting standards require that the contingent consideration be recorded at fair value at the date of acquisition and revalued at subsequent reporting dates under the acquisition method of accounting. At December 31, 2012, we recorded a $15.3 million accrued liability representing the fair value of this contingent consideration, determined by a probability based model measuring the likelihood of meeting certain volumetric measures identified in the MIPSA.

Changes in the fair value of this accrued liability are included in earnings and reported as Other income (expense) in the Consolidated Statement of Operations. During 2013, the contingent consideration was re-estimated to be $0, resulting in an increase in Other income of $15.3 million in 2013. The elimination of the contingent liability reflects management's belief that these stipulated volumetric thresholds will not be achieved during the contingency period.

The following table summarizes the consideration paid for the Badlands acquisition and the determination of the assets and liabilities acquired at the December 31, 2012 acquisition date.

		December 31, 2012
Cash	$	975.8
Contingent consideration		15.3
Total consideration	$	991.1
Assets acquired and liabilities assumed		
Financial assets	$	35.4
Inventory		16.2
Property, plant and equipment		295.3
Intangible assets		679.6
Financial liabilities		(35.4)
Total net assets	$	991.1

Intangible assets consist of customer contracts and relationships acquired in the Badlands acquisition. Using relevant information and assumptions, the fair value of acquired identifiable intangible assets at the date of acquisition was determined. Fair value is generally calculated as the present value of estimated future cash flows. Key assumptions include probability of contracts under negotiation, renewals of existing contracts, economic incentives to retain customers, past and future volumes, current and future capacity of the gathering system, pricing volatility and the discount rate. See Note 6 for details of amortization method for intangible assets.

Pro Forma Results

As the Badlands acquisition was completed on December 31, 2012, there were no results of operations attributable to this acquisition for 2012. In 2012, we incurred $6.1 million of acquisition-related costs associated with the Badlands acquisition (included in Other expense in our consolidated statement of operations).

Our Annual Report for the year ended 2012 included preliminary pro forma information assuming that the Badlands acquisition had been completed on January 1, 2011. In 2013, we finalized amortization methods for Badlands intangible assets and estimated useful lives for both tangible and intangible assets of Badlands.

The following unaudited pro forma consolidated results of operations for the years ended 2012 and 2011 has been updated to include the effects of our 2013 amortization method policy decisions.

	Year Ended December 31,	
	2012	2011
	(In millions, except per unit amounts)	
Revenues	$ 5,907.8	$ 6,990.7
Net income	157.4	182.6
Net income attributable to limited partners	63.1	104.6
Net income per limited partner unit - Basic and diluted	$ 0.63	$ 1.10

The pro forma consolidated results of operations include adjustments to include the reported results of the acquired company for 2012 and 2011, as adjusted to:

- exclude the financial results of assets retained by the seller;
- report revenues from the purchase and sale of crude oil inventory with the same counterparty on a net basis to conform to our accounting policy;
- report revenues from the purchases and sales of certain Badlands natural gas processing agreements in which we are in substance an agent rather than a principal on a net basis;
- include the incremental depreciation expenses associated with the fair value adjustments to property, plant and equipment as a result of applying the acquisition method of accounting (assumed straight-line method over useful lives of 15-20 years);
- include the amortization expense associated with the fair value adjustments to definite-lived intangibles in a manner that follows the expected pattern of services provided to customers, over a useful life of 20 years;
- include the financing costs associated with the debt offering and borrowings under our TRP Revolver used to fund a portion of the acquisition;
- adjust the attribution of net income to general partners and limited partners, and the calculation of weighted average basic and diluted units to give effect to the equity offering used to fund a portion of the acquisition; and
- exclude $6.1 million of acquisition costs incurred in 2012 that were directly related to the transaction.

The pro forma information is not necessarily indicative of the results of operations that would have occurred had the transactions been made at the beginning of the periods presented or the future results of the combined operations.

2011 Acquisitions

In March 2011, we acquired a refined petroleum products and crude oil storage and terminaling facility in Channelview, Texas on Carpenter's Bayou along the Houston Ship Channel (the "Channelview Terminal") for $29.0 million. The Channelview Terminal, with storage capacity of 544 MBbl, can handle multiple grades of blend stocks, petroleum products and crude oil and has potential for expansion, as well as integration with our other logistics operations.

In September 2011, we acquired two refined petroleum products and crude oil storage and terminaling facilities. At the time of the acquisition, the facility on the Hylebos Waterway in the Port of Tacoma, Washington has 758 MBbl of capacity and handles refined petroleum products, crude oil, LPGs and biofuels, including ethanol and biodiesel. The facility on the Patapsco River in Baltimore, Maryland has approximately 505 MBbl of storage capacity. Both terminals contain blending and heating capabilities, and have tanker truck and barge loading and unloading infrastructure. Total cash consideration including working capital for both facilities was $135 million.

Note 5 — Inventories

The components of inventories consisted of the following:

	December 31, 2013	December 31, 2012
Commodities	$ 136.4	$ 82.3
Materials and supplies	14.3	17.1
	$ 150.7	$ 99.4

Note 6 — Property, Plant and Equipment and Intangible Assets

	December 31, 2013	December 31, 2012	Estimated useful life (In Years)
Gathering systems	$ 2,230.1	$ 1,975.3	5 to 20
Processing and fractionation facilities	1,598.0	1,251.6	5 to 25
Terminaling and storage facilities	715.2	462.0	5 to 25
Transportation assets	294.7	292.5	10 to 25
Other property, plant and equipment	121.3	84.6	3 to 25
Land	89.5	87.1	-
Construction in progress	702.8	548.1	-
Property, plant and equipment	5,751.6	4,701.2	
Accumulated depreciation	(1,406.2)	(1,168.0)	
Property, plant and equipment, net	$ 4,345.4	$ 3,533.2	
Intangible assets	$ 681.8	$ 681.9	20
Accumulated amortization	(28.4)	(1.1)	
Intangible assets, net	$ 653.4	$ 680.8	

Intangible assets consist of customer contracts and customer relationships acquired in business acquisitions. The fair value of these acquired intangible assets was determined at the date of acquisition based on the present value of estimated future cash flows. Key valuation assumptions include probability of contracts under negotiation, renewals of existing contracts, economic incentives to retain customers, past and future volumes, current and future capacity of the gathering system, pricing volatility and the discount rate.

Amortization expense attributable to these intangible assets is recorded using a method that closely reflects the cash flow pattern underlying the intangible asset valuation. Amortization of these assets was $27.3 million in 2013. The estimated amortization expense for these intangible assets is approximately $61.4 million, $80.1 million, $88.3 million, $81.5 million and $67.8 million for each of years 2014 through 2018.

Note 7 — Asset Retirement Obligations

Our asset retirement obligations primarily relate to certain gas gathering pipelines and processing facilities, and are included in our consolidated balance sheets as a component of other long-term liabilities. The changes in our aggregate asset retirement obligations are as follows:

	2013	2012	2011
Beginning of period	$ 45.2	$ 42.3	$ 37.5
Change in cash flow estimate	1.4	(1.0)	1.2
Accretion expense	3.9	3.9	3.6
End of period	$ 50.5	$ 45.2	$ 42.3

Note 8 — Investment in Unconsolidated Affiliate

At December 31, 2013, 2012 and 2011, our unconsolidated investment consisted of a 38.8% ownership interest in Gulf Coast Fractionators LP ("GCF").

The following table shows the activity related to our investment in an unconsolidated affiliate for the years indicated:

	2013	2012	2011
Equity earnings	$ 14.8	$ 1.9	$ 8.8
Cash distributions	12.0	2.3	8.4
Cash calls for expansion projects	-	16.8	21.2

Note 9 — Accounts Payable and Accrued Liabilities

The components of accounts payable and accrued liabilities consisted of the following:

	December 31, 2013	December 31, 2012
Commodities	$ 520.8	$ 416.8
Other goods and services	145.1	153.4
Interest	35.8	39.4
Compensation and benefits	1.3	-
Other	18.3	30.2
	$ 721.2	$ 639.8

Note 10 — Debt Obligations

	December 31, 2013	December 31, 2012
Senior secured revolving credit facility, variable rate, due October 2017 (1)	$ 395.0	$ 620.0
Senior unsecured notes, 11¼% fixed rate, due July 2017 (2)	-	72.7
Unamortized discount	-	(2.5)
Senior unsecured notes, 7⅞% fixed rate, due October 2018	250.0	250.0
Senior unsecured notes, 6⅞% fixed rate, due February 2021	483.6	483.6
Unamortized discount	(28.0)	(30.5)
Senior unsecured notes, 6⅜% fixed rate, due August 2022	300.0	400.0
Senior unsecured notes, 5¼% fixed rate, due May 2023	600.0	600.0
Senior unsecured notes, 4¼% fixed rate, due November 2023	625.0	-
Accounts receivable securitization facility, due December 2014 (3)	279.7	-
Total long-term debt	$ 2,905.3	$ 2,393.3
Letters of credit outstanding	$ 86.8	$ 45.3

(1) As of December 31, 2013, availability under our $1.2 billion senior secured revolving credit facility was $718.2 million.
(2) The outstanding balance of the 11¼% Notes was redeemed on July 15, 2013. See "Senior Notes Repayments and Redemptions" below.
(3) All amounts outstanding under the Securitization Facility are reflected as long-term debt in our balance sheet because we have the ability and intent to fund the Securitization Facility's borrowings on a long-term basis.

The following table shows the contractually scheduled maturities of our debt obligations outstanding at December 31, 2013 for the next five years, and in total thereafter:

		Scheduled Maturities of Debt			
	Total	2014	2017	2018	After 2018
Senior secured revolving credit facility	$ 395.0	$ -	$ 395.0	$ -	$ -
Senior unsecured notes	2,258.6	-	-	250.0	2,008.6
Account receivable securitization facility	279.7	279.7	-	-	-
Total	$ 2,933.3	$ 279.7	$ 395.0	$ 250.0	$ 2,008.6

The following table shows the range of interest rates and weighted average interest rate incurred on our variable-rate debt obligations during the year ended December 31, 2013:

	Range of Interest Rates Incurred	Weighted Average Interest Rate Incurred
Senior secured revolving credit facility	1.9% - 4.5%	2.4%
Accounts receivable securitization facility	0.9%	0.9%

Compliance with Debt Covenants

As of December 31, 2013, we were in compliance with the covenants contained in our various debt agreements.

Revolving Credit Agreement

In October 2012, we entered into a Second Amended and Restated Credit Agreement that amended and replaced our variable rate Senior Secured Credit Facility due July 2015 (the “Previous Revolver”) to provide a variable rate Senior Secured Credit Facility due October 3, 2017 (the “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.

We incurred a $1.7 million loss related to a partial write-off of debt issue costs associated with the Previous Revolver 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 our option, either at the base rate or the Eurodollar rate. The base rate is equal to the highest of: (i) Bank of America’s prime rate; (ii) the federal funds rate plus 0.5%; or (iii) the one-month LIBOR rate plus 1.0%, plus an applicable margin ranging from 0.75% to 1.75%. The Eurodollar rate is equal to LIBOR plus an applicable margin ranging from 1.75% to 2.75%.

We are required to pay a commitment fee equal to an applicable rate ranging from 0.3% to 0.5% 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%.

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

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

Senior Unsecured Notes

In February 2011, we exchanged $158.6 million principal amount of our 6⅞% Notes plus payments of $28.6 million including $0.9 million of accrued interest for $158.6 million aggregate principal amount of our 11¼% Notes. The holders of the exchanged Notes are subject to the provisions of the 6⅞% Notes described below. The debt covenants related to the remaining $72.7 million of face value of the 11¼% Notes were removed. This exchange was accounted for as a debt modification whereby the financial effects of the exchange will be recognized over the term of the new debt issue.

In January 2012, we privately placed $400.0 million in aggregate principal amount of our 6⅜% Notes, resulting in approximately $395.5 million of net proceeds, which were used to reduce the borrowings under the TRP Revolver and for general partnership purposes.

In October 2012, $400.0 million in aggregate principal amount of our 5¼% Notes were issued 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 our 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.

In November 2012, we 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 Statement of Cash Flows, and a write off of $2.5 million of unamortized debt issue costs.

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

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

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

The terms of the senior unsecured notes outstanding as of December 31, 2013 were as follows:

Note Issue	Issue Date	Per Annum Interest Rate	Due Date	Dates Interest Paid
"7⅞% Notes"	August 2010	7⅞%	October 15, 2018	April & October 15th
"6⅞% Notes"	February 2011	6⅞%	February 1, 2021	February & August 1st
"6⅜% Notes"	January 2012	6⅜%	August 1, 2022	February & August 1st
"5¼% Notes"	Oct / Dec 2012	5¼%	May 1, 2023	May & November 1st
"4¼% Notes"	May 2013	4¼%	November 15, 2023	May & November 15th

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

Our senior unsecured notes and associated indenture agreements restrict our ability to make distributions to unitholders in the event of default (as defined in the indentures). The indentures also restrict our ability and the ability of certain of our subsidiaries to: (i) incur additional debt or enter into sale and leaseback transactions; (ii) pay certain distributions on or repurchase equity interests (only if such distributions do not meet specified conditions); (iii) make certain investments; (iv) incur liens; (v) enter into transactions with affiliates; (vi) merge or consolidate with another company; and (vii) transfer and sell assets. These covenants are subject to a number of important exceptions and qualifications. If at any time when the notes are rated investment grade by both Moody's Investors Service, Inc. and Standard & Poor's Corporation and no Default or Event of Default (each as defined in the indentures) has occurred and is continuing, many of such covenants will terminate and we will cease to be subject to such covenants.

We may redeem up to 35% of the aggregate principal amount of notes at the redemption dates and prices set forth below (expressed as percentages of principal amounts) plus accrued and unpaid interest and liquidation damages, if any, with the net cash proceeds of one or more equity offerings, provided that: (i) at least 65% of the aggregate principal amount of each of the notes (excluding notes held by us) remains outstanding immediately after the occurrence of such redemption; and (ii) the redemption occurs within 90 days (180 days for the 6⅜% Notes, 5¼% Notes and 4¼ % Notes) of the date of the closing of such equity offering.

Note Issue	Any Date Prior To	Price
7⅞% Notes	October 15, 2013	107.875%
6⅞% Notes	February 1, 2014	106.875%
6⅜% Notes	February 1, 2015	106.375%
5¼% Notes	November 1, 2015	105.250%
4¼% Notes	May 15, 2016	104.250%

We may also redeem all or part of each of the series of notes on or after the redemption dates set forth below at the price for each respective year (expressed as percentages of principal amount) plus accrued and unpaid interest and liquidation damages, if any, on the notes redeemed.

7⅞% Notes		6⅞% Notes		6⅜% Notes		5¼% Notes		4¼% Notes	
Redemption Date: October 15		Redemption Date: February 1		Redemption Date: February 1		Redemption Date: November 1		Redemption Date: May 15	
Year	Price	Year	Price	Year	Price	Year	Price	Year	Price
2014	103.938%	2016	103.438%	2017	103.188%	2017	102.625%	2018	102.125%
2015	101.969%	2017	102.292%	2018	102.125%	2018	101.750%	2019	101.417%
2016 and thereafter	100%	2018	101.146%	2019	101.063%	2019	100.875%	2020	100.708%
		2019 and thereafter	100%	2020 and thereafter	100%	2020 and thereafter	100%	2021 and thereafter	100%

Accounts Receivable Securitization Facility

In January 2013, we entered into the Securitization Facility to provide up to $200.0 million of borrowing capacity at commercial paper or LIBOR market index rates plus a margin through January 2014. Under this Securitization Facility, one of our consolidated subsidiaries (Targa Liquids Marketing and Trade LLC or "TLMT") sells or contributes receivables, without recourse, to another of our consolidated subsidiaries (Targa Receivables LLC or "TRLLC"), a special purpose consolidated subsidiary created for the sole purpose of this Securitization Facility. TRLLC, in turn, sells an undivided percentage ownership in the eligible receivables to a third-party financial institution. Eligible TRLLC 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 or us. Any excess receivables are eligible to satisfy the claims of creditors of TLMT or us.

In December 2013, we entered into a Second Amendment to the Securitization Facility to increase the borrowing capacity to $300.0 million and extend the termination date to December 12, 2014.

April 2013 Shelf

In April 2013, we filed with the SEC a universal shelf registration statement (the "April 2013 Shelf"), which provides us with the ability to offer and sell an unlimited amount of debt and equity securities, subject to market conditions and our capital needs. The April 2013 Shelf expires in April 2016. There was no activity under the April 2013 Shelf during the year ended December 31, 2013.

July 2013 Shelf

In July 2013, we filed with the SEC a universal shelf registration statement that allows us to issue up to an aggregate of $800.0 million of debt or equity securities (the "July 2013 Shelf"). The July 2013 Shelf expires in August 2016. See Note 11 for equity issuances under the July 2013 Shelf.

Debt Re-acquisitions Summary

The debt re-acquisitions described above were reported as follows in our Consolidated Statements of Operations:

	2013	2012
Premium over face value paid upon redemption:		
6⅜ Notes	$ 6.4	$ -
8¼ Notes	-	8.6
11¼ Notes	4.1	-
Recognition of unamortized discount:		
11¼ Notes	2.2	-
Write-off of deferred debt issue costs:		
8¼ Notes	-	2.5
6⅜ Notes	1.0	-
11¼ Notes	1.0	-
Partial write-off of TRP Revolver deferred debt issue cost related to 2012 amendment	-	1.7
Loss on debt redemptions and amendments	$ 14.7	$ 12.8

Note 11 — Partnership Units and Related Matters

In accordance with the Partnership Agreement, we must distribute all of our available cash, as determined by the general partner, to unitholders of record within 45 days after the end of each quarter.

Public Offerings of Common Units

In 2010, we filed with the SEC a universal shelf registration statement (the "2010 Shelf"), which provided us with the ability to offer and sell an unlimited amount of debt and equity securities, subject to market conditions and our capital needs. The 2010 Shelf expired in April 2013. The following transactions were completed under the 2010 Shelf.

- August 2010 – 7,475,000 common units (including underwriters' overallotment option) at a price of $24.80 per common unit, providing net proceeds of $177.8 million. Targa contributed $3.8 million to maintain its 2% general partner interest. We used the net proceeds from this offering to reduce borrowings under our Previous Revolver.

- January 2011 – 9,200,000 common units (including underwriters' overallotment option) at a price of $33.67 per common unit, providing net proceeds of $298.0 million. Targa contributed $6.3 million to maintain its 2% general partner interest. We used the net proceeds from the offering for general partnership purposes, which included reducing borrowings under our Previous Revolver.

- January 2012 – 4,405,000 common units (including underwriters' overallotment option) at a price of $38.30 per common unit, providing net proceeds of $164.8 million. As part of this offering, Targa purchased 1,300,000 common units with an aggregate value of $49.8 million. In addition, Targa contributed $3.5 million to maintain its 2% general partner interest. We used the net proceeds from this offering for general partnership purposes, including the repayment of indebtedness.

- November 2012 – 10,925,000 common units (including underwriters' overallotment option) at a price of $36.00 per common unit, providing net proceeds of $378.2 million. Targa contributed $8.0 million to maintain its 2% general partner interest. We used the net proceeds from this offering to fund a portion of the $975.8 million purchase price of the Badlands acquisition.

In July 2012, we filed with the SEC a universal shelf registration statement that, subject to effectiveness at the time of use, allows us to issue up to an aggregate of $300.0 million of debt or equity securities (the "2012 Shelf"). The 2012 Shelf expires in August 2015.

In August 2012, we entered into an Equity Distribution Agreement (the "2012 EDA") with Citigroup Global Markets Inc. ("Citigroup") pursuant to which we may sell, at our option, up to an aggregate of $100.0 million of our common units through Citibank, as sales agent, under the 2012 Shelf. During the year ended December 31, 2013, we issued 2,420,046 common units under the 2012 EDA, receiving net proceeds of $94.8 million. Targa contributed $2.0 million to us to maintain its 2% general partner interest.

In March 2013, we entered into a second Equity Distribution Agreement under the 2012 Shelf (the "March 2013 EDA") with Citigroup, Deutsche Bank Securities Inc. ("Deutsche Bank"), Raymond James & Associates, Inc. ("Raymond James") and UBS Securities LLC ("UBS"), as our sales agents, pursuant to which we may sell, at our option, up to an aggregate of $200.0 million of our common units. During the year ended December 31, 2013, we issued 4,204,751 common units receiving net proceeds of $197.5 million. Targa contributed $4.1 million to maintain its 2% general partner interest.

In August 2013, we entered into an Equity Distribution Agreement under the July 2013 Shelf (the "August 2013 EDA") with Citigroup, Deutsche Bank, Morgan Stanley & Co. LLC, Raymond James, RBC Capital Markets, LLC, UBS and Wells Fargo Securities, LLC, as our sales agents, pursuant to which we may sell, at our option, up to an aggregate of $400.0 million of our common units. During the year ended 2013, we issued 4,529,641 common units under the August 2013 EDA, receiving net proceeds of $225.6 million. Targa contributed $4.7 million to us to maintain its 2% general partner interest.

Subsequent Event

In January 2014, we issued 1,118,147 common units and received proceeds of $56.2 million, net of commissions and fees, pursuant to the August 2013 EDA. Targa contributed $1.2 million to maintain its 2% general partner interest.

Distributions

In accordance with the Partnership Agreement, we must distribute all of our available cash, as determined by the general partner, to unitholders of record within 45 days after the end of each quarter. The following table details the distributions declared and/or paid by us for the year ended December 31, 2013, 2012 and 2011.

Three Months Ended	Date Paid or to be Paid	Distributions: Limited Partners Common	Distributions: General Partner Incentive	Distributions: General Partner 2%	Distributions: Total	Distributions per Limited Partner Unit
		(In millions, except per unit amounts)				
2013						
December 31, 2013	February 14, 2014	$ 84.0	$ 29.5	$ 2.3	$ 115.8	$ 0.7475
September 30, 2013	November 14, 2013	79.4	26.9	2.2	108.5	0.7325
June 30, 2013	August 14, 2013	75.8	24.6	2.0	102.4	0.7150
March 31, 2013	May 15, 2013	71.7	22.1	1.9	95.7	0.6975
2012						
December 31, 2012	February 14, 2013	$ 69.0	$ 20.1	$ 1.8	$ 90.9	$ 0.6800
September 30, 2012	November 14, 2012	59.1	16.1	1.5	76.7	0.6625
June 30, 2012	August 14, 2012	57.3	14.4	1.5	73.2	0.6425
March 31, 2012	May 15, 2012	55.5	12.7	1.4	69.6	0.6225
2011						
December 31, 2011	February 14, 2012	$ 53.7	$ 11.0	$ 1.3	$ 66.0	$ 0.6025
September 30, 2011	November 14, 2011	49.4	8.8	1.2	59.4	0.5825
June 30, 2011	August 12, 2011	48.3	7.8	1.2	57.3	0.5700
March 31, 2011	May 13, 2011	47.3	6.8	1.1	55.2	0.5575

Note 12 — Earnings per Limited Partner Unit

The following table sets forth the computation of basic and diluted net income per limited partner unit for the years ended December 31, 2013, 2012 and 2011:

	Year Ended December 31, 2013	2012	2011
Net income	$ 258.6	$ 203.2	$ 245.5
Less: Net income attributable to noncontrolling interests	25.1	28.6	41.0
Net income attributable to Targa Resources Partners LP	$ 233.5	$ 174.6	$ 204.5
Net income attributable to general partner	107.5	66.7	38.0
Net income attributable to limited partners	126.0	107.9	166.5
Net income attributable to Targa Resources Partners LP	$ 233.5	$ 174.6	$ 204.5
Weighted average units outstanding - basic	105.5	90.1	84.1
Net income available per limited partner unit - basic	$ 1.19	$ 1.20	$ 1.98
Weighted average units outstanding	105.5	90.1	84.1
Dilutive effect of unvested stock awards	0.2	0.1	0.1
Weighted average units outstanding - diluted	105.7	90.2	84.2
Net income available per limited partner unit - diluted	$ 1.19	$ 1.20	$ 1.98

Note 13 — Derivative Instruments and Hedging Activities

Commodity Hedges

The primary purpose of our commodity risk management activities is to manage our exposure to commodity price risk and reduce volatility in our operating cash flow due to fluctuations in commodity prices. We have hedged the commodity prices associated with a portion of our expected (i) natural gas equity volumes in our Field Gathering and Processing operations and (ii) NGL and condensate equity volumes predominately in our Field Gathering and Processing segment and the LOU business unit in our Coastal Gathering and Processing segment that result from its percent-of-proceeds processing arrangements. These hedge positions will move favorably in periods of falling prices and unfavorably in periods of rising prices. We have designated these derivative contracts as cash flow hedges for accounting purposes.

The hedges generally match the NGL product composition and the NGL and natural gas delivery points to those of our physical equity volumes. The NGL hedges may be transacted as specific NGL hedges or as baskets of ethane, propane, normal butane, isobutane and natural gasoline based upon our expected equity NGL composition. We believe this approach avoids uncorrelated risks resulting from employing hedges on crude oil or other petroleum products as "proxy" hedges of NGL prices. Our natural gas and NGL hedges are settled using published index prices for delivery at various locations, which closely approximate our actual natural gas and NGL delivery points.

We hedge a portion of our condensate sales using crude oil hedges that are based on the New York Mercantile Exchange ("NYMEX") futures contracts for West Texas Intermediate light, sweet crude, which approximates the prices received for condensate. This necessarily exposes us to a market differential risk if the NYMEX futures do not move in exact parity with the sales price of our underlying condensate equity volumes.

At December 31, 2013, the notional volumes of our commodity hedges for equity volumes were:

Commodity	Instrument	Unit	2014	2015	2016
Natural Gas	Swaps	MMBtu/d	48,050	34,551	25,500
NGL	Swaps	Bbl/d	1,125	-	-
Condensate	Swaps	Bbl/d	2,450	-	-

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

Our derivative contracts are subject to netting arrangements that allow net cash settlement of offsetting asset and liability positions with the same counterparty. We record derivative assets and liabilities on our Consolidated Balance Sheets on a gross basis, without considering the effect of master netting arrangements. The following schedules reflect the fair values of our derivative instruments and their location in our Consolidated Balance Sheets as well as pro forma reporting assuming that we reported derivatives subject to master netting agreements on a net basis:

		Fair Value as of December 31, 2013		Fair Value as of December 31, 2012	
	Balance Sheet Location	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Derivatives designated as hedging instruments					
Commodity contracts	Current	$ 2.0	$ (7.7)	$ 29.2	$ (7.2)
	Long-term	3.1	(1.4)	5.1	(4.8)
Total derivatives designated as hedging instruments		$ 5.1	$ (9.1)	$ 34.3	$ (12.0)
Derivatives not designated as hedging instruments					
Commodity contracts	Current	$ -	$ (0.3)	$ 0.1	$ (0.2)
Total derivatives not designated as hedging instruments		$ -	$ (0.3)	$ 0.1	$ (0.2)
Total current position		$ 2.0	$ (8.0)	$ 29.3	$ (7.4)
Total long-term position		3.1	(1.4)	5.1	(4.8)
Total derivatives		$ 5.1	$ (9.4)	$ 34.4	$ (12.2)

The pro forma impact of reporting derivatives in the Consolidated Balance Sheet is as follows:

	Gross Presentation		Pro forma Net Presentation	
December 31, 2013	**Asset Position**	**Liability Position**	**Asset Position**	**Liability Position**
Current position				
Counterparties with offsetting position	$ 1.9	$ (4.4)	$ -	$ (2.5)
Counterparties without offsetting position - assets	0.1	-	0.1	-
Counterparties without offsetting position - liabilities	-	(3.6)	-	(3.6)
	2.0	(8.0)	0.1	(6.1)
Long-term position				
Counterparties with offsetting position	0.7	(1.2)	-	(0.5)
Counterparties without offsetting position - assets	2.4	-	2.4	-
Counterparties without offsetting position - liabilities	-	(0.2)	-	(0.2)
	3.1	(1.4)	2.4	(0.7)
Total derivatives				
Counterparties with offsetting position	2.6	(5.6)	-	(3.0)
Counterparties without offsetting position - assets	2.5	-	2.5	-
Counterparties without offsetting position - liabilities	-	(3.8)	-	(3.8)
	$ 5.1	$ (9.4)	$ 2.5	$ (6.8)
December 31, 2012				
Current position				
Counterparties with offsetting position	$ 23.8	$ (7.4)	$ 16.4	$ -
Counterparties without offsetting position - assets	5.5	-	5.5	-
Counterparties without offsetting position - liabilities	-	-	-	-
	29.3	(7.4)	21.9	-
Long-term position				
Counterparties with offsetting position	4.4	(2.8)	1.6	-
Counterparties without offsetting position - assets	0.7	-	0.7	-
Counterparties without offsetting position - liabilities	-	(2.0)	-	(2.0)
	5.1	(4.8)	2.3	(2.0)
Total derivatives				
Counterparties with offsetting position	28.2	(10.2)	18.0	-
Counterparties without offsetting position - assets	6.2	-	6.2	-
Counterparties without offsetting position - liabilities	-	(2.0)	-	(2.0)
	$ 34.4	$ (12.2)	$ 24.2	$ (2.0)

The fair value of our derivative instruments, depending on the type of instrument, was determined by the use of present value methods or standard option valuation models with assumptions about commodity prices based on those observed in underlying markets.

The estimated fair value of our derivative instruments was a net liability of $4.3 million as of December 31, 2013. The estimated fair value is net of an adjustment for credit risk based on the default probabilities by year as indicated by market quotes for the counterparties' credit default swap rates. The credit risk adjustment was immaterial for all periods presented.

Our payment obligations in connection with substantially all of these hedging transactions are secured by a first priority lien in the collateral securing our senior secured indebtedness that ranks equal in right of payment with liens granted in favor of our senior secured lenders.

The following tables reflect amounts recorded in OCI and amounts reclassified from OCI to revenue and expense for the periods indicated:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivatives (Effective Portion) 2013	2012	2011
Interest rate contracts	$ -	$ -	$ (4.4)
Commodity contracts	(5.8)	76.4	(33.4)
	$ (5.8)	$ 76.4	$ (37.8)

Location of Gain (Loss)	Gain (Loss) Reclassified from OCI into Income (Effective Portion) 2013	2012	2011
Interest expense, net	$ (6.1)	$ (7.9)	$ (8.1)
Revenues	21.2	43.9	(34.7)
	$ 15.1	$ 36.0	$ (42.8)

Hedge ineffectiveness was immaterial for all periods presented.

Our consolidated earnings are also affected by our use of the mark-to-market method of accounting for derivative instruments that do not qualify for hedge accounting or that have not been designated as hedges. The changes in fair value of these instruments are recorded on the balance sheet and through earnings (i.e., using the "mark-to-market" method) rather than being deferred until the anticipated transaction settles. The use of mark-to-market accounting for financial instruments can cause non-cash earnings volatility due to changes in the underlying commodity price indices. Gain (loss) recognized on commodity derivatives not designated as hedging instruments was immaterial for all periods presented.

Derivatives Not Designated as Hedging Instruments	Location of Gain Recognized in Income on Derivatives	Gain (Loss) Recognized in Income on Derivatives 2013	2012	2011
Commodity contracts	Revenue	$ (0.1)	$ 0.7	$ 1.7
Interest rate swaps	Other income (expense)	-	-	(5.0)

The following table shows the deferred gains (losses) included in accumulated OCI that will be reclassified into earnings through the end of 2016:

	December 31, 2013	December 31, 2012
Commodity hedges	$ (3.7)	$ 23.1
Interest rate hedges	(2.4)	(8.5)

As of December 31, 2013, net losses of $5.6 million on commodity hedges and net losses of $2.4 million on terminated interest rate swaps recorded in OCI are expected to be reclassified to revenue and interest expense during the next twelve months.

See Note 14 for additional disclosures related to derivative instruments and hedging activities.

Note 14 — Fair Value Measurements

Under GAAP, our Consolidated Balance Sheets reflect a mixture of measurement methods for financial assets and liabilities ("financial instruments"). Derivative financial instruments are reported at fair value in our consolidated balance sheet. Other financial instruments are reported at historical cost or amortized cost in our consolidated balance sheet, with fair value measurements for these instruments provided as supplemental information.

The following are additional qualitative and quantitative disclosures regarding fair value measurements of financial instruments.

Fair Value of Derivative Financial Instruments

Our derivative instruments consist of financially settled commodity swaps and option contracts and fixed price commodity contracts with certain counterparties. We determine the fair value of our derivative contracts using a discounted cash flow model for swaps and a standard option-pricing model for options, based on inputs that are readily available in public markets. We have consistently applied these valuation techniques in all periods presented and believe we have obtained the most accurate information available for the types of derivative contracts we hold.

The fair values of our derivative instruments, which aggregate to a net liability position of $4.3 million as of December 31, 2013, are sensitive to changes in forward pricing on natural gas, NGLs and crude oil. This liability position reflects the present value, adjusted for counterparty credit risk, of the amount we expect to receive in the future on our derivative contracts. If forward pricing on natural gas, NGLs and crude oil were to increase by 10%, the result would be a fair value reflecting a net liability of $29.9 million, ignoring an adjustment for counterparty credit risk. If forward pricing on natural gas, NGLs and crude oil were to decrease by 10%, the result would be a fair value reflecting a net asset of $21.3 million, ignoring an adjustment for counterparty credit risk.

Fair Value of Other Financial Instruments

The contingent consideration obligation related to our Badlands acquisition is reported at fair value. Due to their cash or near-cash nature, the carrying value of other financial instruments included in working capital (i.e., cash and cash equivalents, accounts receivable, accounts payable) approximates their fair value. As such, long-term debt is primarily the other financial instrument for which our carrying value could vary significantly from fair value. We determined the supplemental fair value disclosures for our long-term debt as follows:

- TRP Revolver and Securitization Facility are based on carrying value which approximates fair value as its interest rate is based on prevailing market rates; and

- Senior unsecured notes are based on quoted market prices derived from trades of the debt.

Fair Value Hierarchy

We categorize the inputs to the fair value measurements using a three-tier fair value hierarchy that prioritizes the significant inputs used in measuring fair value:

- Level 1 – observable inputs such as quoted prices in active markets;

- Level 2 – inputs other than quoted prices in active markets that we can directly or indirectly observe to the extent that the markets are liquid for the relevant settlement periods; and

- Level 3 – unobservable inputs in which little or no market data exists, therefore we must develop our own assumptions.

The following table shows a breakdown by fair value hierarchy category for (1) financial instruments measurements included in our Consolidated Balance Sheets at fair value and (2) supplemental fair value disclosures for other financial instruments:

	December 31, 2013				
	Carrying Value	Fair Value			
		Total	Level 1	Level 2	Level 3
Financial Instruments Recorded on Our Consolidated Balance Sheet at Fair Value:					
Assets from commodity derivative contracts	$ 5.1	$ 5.1	$ -	$ 3.4	$ 1.7
Liabilities from commodity derivative contracts	9.4	9.4	-	8.4	1.0
Badlands contingent consideration liability	-	-	-	-	-
Financial Instruments Recorded on Our Consolidated Balance Sheet at Carrying Value:					
Cash and cash equivalents	57.5	57.5	-	-	-
Senior secured revolving credit facility	395.0	395.0	-	395.0	-
Senior unsecured notes	2,230.6	2,253.5	-	2,253.5	-
Accounts receivable securitization facility	279.7	279.7	-	279.7	-

	December 31, 2012				
	Carrying Value	Fair Value			
		Total	Level 1	Level 2	Level 3
Financial Instruments Recorded on Our Consolidated Balance Sheet at Fair Value:					
Assets from commodity derivative contracts	$ 34.4	$ 34.4	$ -	$ 34.4	$ -
Liabilities from commodity derivative contracts	12.2	12.2	-	11.6	0.6
Badlands contingent consideration liability	15.3	15.3	-	-	15.3
Financial Instruments Recorded on Our Consolidated Balance Sheet at Carrying Value:					
Cash and cash equivalents	68.0	68.0	-	-	-
Senior secured revolving credit facility	620.0	620.0	-	620.0	-
Senior unsecured notes	1,773.3	1,945.2	-	1,945.2	-

Additional Information Regarding Level 3 Fair Value Measurements Included in Our Consolidated Balance Sheets

As of December 31, 2013, we reported certain of our natural gas basis swaps at fair value using Level 3 inputs due to such derivatives not having observable market prices for substantially the full term of the derivative asset or liability. For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations whose contract length extends into unobservable periods.

The fair value of these natural gas basis swaps is determined using a discounted cash flow valuation technique based on a forward commodity basis curve. For these derivatives, the primary input to the valuation model is the forward commodity basis curve, which is based on observable or public data sources and extrapolated when observable prices are not available.

As of December 31, 2013, we had thirteen natural gas basis swaps categorized as Level 3. The significant unobservable inputs used in the fair value measurements of our Level 3 derivatives are the forward natural gas basis curves, for which a significant portion of the derivative's term is beyond available forward pricing. The change in the fair value of Level 3 derivatives associated with a 10% change in the forward basis curve where prices are not observable is immaterial.

The Badlands acquisition agreement also provided for a contingent payment of $50 million conditioned on achieving stipulated crude gathering volumes by mid-2014. In 2012, we recorded a contingent consideration liability of $15.3 million as part of the purchase consideration for the Badlands acquisition (see Note 4). The fair value of this contingent liability was determined using a probability-based model measuring the likelihood of meeting certain volumetric measures identified in the MIPSA. These probability-based inputs are not observable; the entire valuation of the contingent consideration is categorized in Level 3. As of December 2013, management does not believe that these thresholds will be achieved during the contingency period.

The following table summarizes the changes in fair value of our financial instruments classified as Level 3 in the fair value hierarchy:

	Commodity Derivative Contracts Liability/ (Asset)	Contingent Liability
Balance, December 31, 2010	$ (11.6)	$ -
Settlements included in Revenue	3.7	-
Transfers out of Level 3	7.9	-
Balance, December 31, 2011	-	-
Valuation of contingent liability	-	15.3
Settlements included in Revenue	(0.1)	-
Unrealized losses included in OCI	0.7	-
Balance, December 31, 2012	0.6	15.3
Settlements included in Revenue	(1.3)	-
Change in valuation of contingent liability included in Other Income	-	(15.3)
Balance, December 31, 2013	$ (0.7)	$ -

During 2011, we transferred $7.9 million in derivative assets out of Level 3 and into Level 2. This transfer related to long-term OTC swaps executed in 2010 for NGL products with calendar year 2013 deliveries for which pricing was extrapolated (Level 3) for some periods. As of December 31, 2011, all products had actively traded contracts through December 2013 with open interest and settlement prices. Accordingly, we were no longer required to extrapolate to value our contracts and reclassified these instruments as Level 2.

There has been no material transfer of assets or liabilities among the three levels of the fair value hierarchy during the years ended December 31, 2013 or 2012.

Note 15 — Related Party Transactions

Targa Resources Corp.

Targa provides general and administrative and other services to us associated with our existing assets and assets acquired from third parties. The Partnership Agreement governs the reimbursement of costs incurred on the behalf of us.

The employees supporting our operations are employees of Targa. We reimburse Targa for the payment of certain operating expenses, including compensation and benefits of operating personnel assigned to our assets, and for the provision of various general and administrative services for our benefit. Targa performs centralized corporate functions for us, such as legal, accounting, treasury, insurance, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes, engineering and marketing. Since October 1, 2010, after the final conveyance of assets to us by Targa, substantially all of Targa's general and administrative costs have been and will continue to be allocated to us, other than Targa's direct costs of being a separate public reporting company.

Targa has reimbursed us for maintenance capital expenditures totaling $17.0 million as of December 31, 2013, which are required to be made in connection with a settlement agreement with the New Mexico Environment Department relating to air emissions at three gas processing plants operated by our Versado Gas Processors, LLC joint venture, with $0.2 million reimbursed to us during the year ended December 31, 2013. These capital projects are substantially complete.

The following table summarizes transactions with Targa. Management believes these transactions are executed on terms that are fair and reasonable.

	2013	2012	2011
Parent billings of payroll and related costs included in operating expense	$ 109.7	$ 97.2	$ 87.4
Parent allocation of general & administrative expense	134.3	124.0	115.2
Cash distributions to Targa based on unit ownership	138.2	92.7	60.3
Contributions from Targa, net	-	1.0	13.2

Transactions with Unconsolidated Affiliate

For the years 2013, 2012 and 2011, transactions with GCF included in revenues were $0.4 million, $0.1 million and $0.8 million. For the same periods, transactions with GCF included in costs and expenses were $6.3 million, $1.9 million and $0.4 million. These transactions were at market prices consistent with similar transactions with other nonaffiliated entities. We are subject to paying a deficiency fee in instances where we do not deliver minimum volume requirements as outlined in our partnership and fractionation agreements with GCF.

Relationship with Laredo Petroleum Holdings Inc.

Peter Kagan, a director of our general partner, is a Managing Director of Warburg Pincus LLC and is also a director of Laredo Petroleum Holdings Inc. ("Laredo") from whom we buy natural gas and NGL products. Affiliates of Warburg Pincus LLC own a controlling interest in Laredo. Purchases from Laredo during 2013 totaled $108.6 million. These transactions were at market prices consistent with similar transactions with other nonaffiliated entities.

Note 16 — Commitments and Contingencies

Future lease obligations are presented below in aggregate and for each of the next five fiscal years.

	In Aggregate	2014	2015	2016	2017	2018
Operating leases (1)	$ 33.9	$ 8.0	$ 7.8	$ 7.4	$ 6.1	$ 4.6
Land site lease and right-of-way (2)	7.9	1.7	1.6	1.6	1.6	1.4
	$ 41.8	$ 9.7	$ 9.4	$ 9.0	$ 7.7	$ 6.0

(1) Includes minimum payments on lease obligations for office space, railcars and tractors.
(2) Land site lease and right-of-way provides for surface and underground access for gathering, processing and distribution assets that are located on property not owned by us. These agreements expire at various dates through 2099.

Total expenses on lease obligations were:

	2013	2012	2011
Operating leases (1)	$ 23.3	$ 16.1	$ 14.2
Land site lease and right-of-way	3.6	3.3	2.8

(1) Includes short-term leases for items such as compressors and equipment.

Environmental

Environmental liabilities were not significant as of December 31, 2013.

Legal Proceedings

We are a party to various legal proceedings and/or regulatory proceedings and certain claims, suits and complaints arising in the ordinary course of business that have been filed or are pending against us. We believe all such matters are without merit or involve amounts which, if resolved unfavorably, would not have a material effect on our financial position, results of operations, or cash flows.

Note 17 — Significant Risks and Uncertainties

Nature of Operations in Midstream Energy Industry

We operate in the midstream energy industry. Our business activities include gathering, processing, fractionating and storage of natural gas, NGLs and crude oil. Our results of operations, cash flows and financial condition may be affected by changes in the commodity prices of these hydrocarbon products and changes in the relative price levels among these hydrocarbon products. In general, the prices of natural gas, NGLs, condensate and other hydrocarbon products are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control.

Our profitability could be impacted by a decline in the volume of natural gas, NGLs and condensate transported, gathered or processed at our facilities. A material decrease in natural gas or condensate production or condensate refining, as a result of depressed commodity prices, a decrease in exploration and development activities, or otherwise, could result in a decline in the volume of natural gas, NGLs and condensate handled by our facilities.

A reduction in demand for NGL products by the petrochemical, refining or heating industries, whether because of (i) general economic conditions, (ii) reduced demand by consumers for the end products made with NGL products, (iii) increased competition from petroleum-based products due to the pricing differences, (iv) adverse weather conditions, (v) government regulations affecting commodity prices and production levels of hydrocarbons or the content of motor gasoline or (vi) other reasons, could also adversely affect our results of operations, cash flows and financial position.

The principal market risks are exposure to changes in commodity prices, as well as changes in interest rates.

Commodity Price Risk

A majority of the revenues from the gathering and processing business are derived from percent-of-proceeds contracts under which we receive a portion of the natural gas and/or NGLs or equity volumes as payment for services. The prices of natural gas and NGLs are subject to market fluctuations in response to changes in supply, demand, market uncertainty and a variety of additional factors beyond our control.

In an effort to reduce the variability of our cash flows, we have hedged the commodity price associated with a significant portion of our expected natural gas equity volumes through 2016 and NGL and condensate equity volumes through 2014 by entering into derivative financial instruments including swaps and purchased puts (or floors). We hedge a higher percentage of our expected equity volumes in the current year as compared to future years where the volume forecasting risk is greater. With swaps, we typically receive an agreed upon fixed price for a specified notional quantity of natural gas or NGLs and pays the hedge counterparty a floating price for that same quantity based upon published index prices. Since we receive from our customers substantially the same floating index price from the sale of the underlying physical commodity, these transactions are designed to effectively lock-in the agreed fixed price in advance for the volumes hedged. In order to avoid having a greater volume hedged than actual equity volumes, we typically limit our use of swaps to hedge the prices of less than our expected natural gas and NGL equity volumes. We utilize purchased puts (or floors) to hedge additional expected equity commodity volumes without creating volumetric risk. Our commodity hedges may expose us to the risk of financial loss in certain circumstances.

The fair value of commodity derivative instruments, depending on the type of instrument, was determined by the use of present value methods or standard option valuation models with assumptions about commodity prices based on those observed in underlying markets. See Note 13.

Interest Rate Risk

We are exposed to changes in interest rates, primarily as a result of our variable rate borrowings under our credit facility.

Counterparty Risk – Credit and Concentration

Derivative Counterparty Risk

Where we are exposed to credit risk in our financial instrument transactions, management analyzes the counterparty's financial condition prior to entering into an agreement, establishes credit and/or margin limits and monitors the appropriateness of these limits on an ongoing basis. Generally, management does not require collateral and does not anticipate nonperformance by our counterparties.

We have master netting provisions in the International Swap Dealers Association agreements with all of our derivative counterparties. These netting provisions allow us to net settle asset and liability positions with the same counterparties, and would reduce our maximum loss due to counterparty credit risk by $2.2 million as of December 31, 2013. The range of losses attributable to our individual counterparties would be between $1.0 million and $1.2 million, depending on the counterparty in default.

Our credit exposure related to commodity derivative instruments is represented by the fair value of contracts with a net positive fair value, representing expected future receipts, at the reporting date. At such times, these outstanding instruments expose us to losses in the event of nonperformance by the counterparties to the agreements. Should the creditworthiness of one or more of our counterparties decline, our ability to mitigate nonperformance risk is limited to a counterparty agreeing to either a voluntary termination and subsequent cash settlement or a novation of the derivative contract to a third party. In the event of a counterparty default, we may sustain a loss and our cash receipts could be negatively impacted.

As of December 31, 2013, affiliates of Bank of America Merrill Lynch ("BAML"), Securities Americas LLC ("Natixis") and Barclays PLC ("Barclays"), accounted for 37%, 26% and 24%, of our counterparty credit exposure related to commodity derivative instruments. BAML, Natixis and Barclays are major financial institutions that possess investment grade credit ratings based upon minimum credit ratings assigned by Moody's Investors Service, Inc. and Standard & Poor's Corporation.

Customer Credit Risk

We extend credit to customers and other parties in the normal course of business. We have established various procedures to manage our credit exposure, including initial credit approvals, credit limits and terms, letters of credit, and rights of offset. We also use prepayments and guarantees to limit credit risk to ensure that our established credit criteria are met. The following table summarizes the activity affecting our allowance for bad debts:

	2013	2012	2011
Balance at beginning of year	$ 0.7	$ 2.2	$ 7.7
Additions	0.2	-	0.5
Deductions	-	(1.5)	(6.0)
Balance at end of year	$ 0.9	$ 0.7	$ 2.2

Significant Commercial Relationships

No customer accounted for more than 10% of our consolidated revenues for 2013.

	2013	2012	2011
% of consolidated revenues			
Chevron Phillips Chemical Company LLC	8%	10%	12%

All transactions in the above table were associated with the Marketing and Distribution segment.

Casualty or Other Risks

Targa maintains coverage in various insurance programs on our behalf, which provides us with property damage, business interruption and other coverage which is customary for the nature and scope of our operations. A portion of the insurance costs described above is allocated to us by Targa through the Partnership Agreement described in Note 15.

Management believes that Targa has adequate insurance coverage, although insurance may not cover every type of interruption that might occur. As a result of insurance market conditions, premiums and deductibles for certain insurance policies have increased substantially, and in some instances, certain insurance may become unavailable, or available for only reduced amounts of coverage. As a result, Targa may not be able to renew existing insurance policies or procure other desirable insurance on commercially reasonable terms, if at all.

If we were to incur a significant liability for which we were not fully insured, it could have a material impact on our consolidated financial position and results of operations. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur. Any event that interrupts the revenues generated by us, or which causes us to make significant expenditures not covered by insurance, could reduce our ability to meet our obligations. Furthermore, even when a business interruption event is covered, it could affect interperiod results as we would not recognize the contingent gain until realized in a period following the incident.

Note 18 — Other Operating Expense

	2013	2012		2011
Abandoned Project Costs	$ 0.7	$ -		$ -
Loss on sale or disposal of assets	3.9	15.6	(1)	0.2
Casualty loss	4.3	3.6		-
Miscellaneous business tax	0.7	0.7		-
	$ 9.6	$ 19.9		$ 0.2

(1) Includes a $15.4 million loss due to a write-off of our investment in the Yscloskey joint interest processing plant in Southeastern Louisiana. Following Hurricane Isaac, the joint venture owners elected not to restart the plant.

Note 19 — Supplemental Cash Flow Information

	2013	2012	2011
Cash:			
Interest paid, net of capitalized interest (1)	$ 119.1	$ 92.5	$ 92.7
Income taxes paid, net of refunds	2.3	2.3	2.5
Non-cash:			
Deadstock inventory transferred to property, plant and equipment	30.4	3.0	0.7
Badlands acquisition contingent consideration	-	15.3	-
Accrued distribution equivalent rights	1.7	0.5	0.1
Change in capital accruals	(0.4)	(34.4)	(4.8)
Transfers from materials and supplies to property, plant and equipment	20.5	-	-
Change in ARO estimate	1.4	(1.0)	1.2

(1) Interest capitalized on expansion projects was $28.0 million, $13.6 million and $3.4 million for the years ended December 31, 2013, 2012 and 2011.

Note 20 — Compensation Plans

For the years ended December 31, 2013, 2012 and 2011 our results include compensation expenses from the following sources:

- Partnership Long-Term Incentive Plan
  - Performance Units
  - Director grants

Allocated compensation cost related to:

- Targa Resources Investments Inc. Long-Term Incentive Plan — Cash-settled Performance Units
- 2010 TRC Stock Incentive Plan
  - Restricted Stock Awards
  - Restricted Stock Units Awards
- TRC Equity-Settled Awards
- Targa 401(k) Plan

Long-Term Incentive Plans

Performance Units

In 2007, both Targa and we adopted Long-Term Incentive Plans ("LTIP") for employees, consultants, directors and non-employee directors of Targa and its affiliates who perform services for Targa or its affiliates. The performance units granted under these plans are linked to the performance of our common units. These plans provide for, among other things, the grant of both cash-settled and equity-settled performance units. Performance unit awards may also include distribution equivalent rights ("DERs"). The LTIPs are administered by the compensation committee (the "Committee") of the Targa Board of Directors. Total units authorized under the LTIP are 1,680,000.

Each performance unit will entitle the grantee to the value of our common unit on the vesting date multiplied by a stipulated vesting percentage determined from our ranking in a defined peer group. Currently, the performance period for most awards is three years, except for certain awards granted in December 2013, which provide for two, three or four-year vesting periods. The grantee will receive the vested unit value in cash or common units depending on the terms of the grant. The grantee may also be entitled to the value of any DERs based on the notional distributions accumulated during the vesting period times the vesting percentage. DERs are cash settled for both paid in cash and equity-settled performance units.

Compensation cost for equity-settled performance units is recognized as an expense over the performance period based on fair value at the grant date. Fair value is calculated using a simulated unit price that incorporates peer ranking. DERs associated with equity-settled performance units are accrued over the performance period as a reduction of owners' equity.

Compensation expense for cash-settled performance units and any related DERs will ultimately be equal to the cash paid to the grantee upon vesting. However, throughout the performance period we must record an accrued expense based on an estimate of that future pay-out. Targa used a Monte Carlo simulation model to estimate accruals throughout the vesting period. In 2012, Targa changed the volatility assumption in the Monte Carlo simulation model from implied volatility to historical volatility. We consider historical volatility to be more appropriate than implied volatility because it provides a more reliable indication of future volatility.

Our LTIP – Equity-Settled Performance Units

We started issuing equity-settled performance units in 2011. The following table summarizes activities of our equity-settled performance units for the years ended December 31, 2013, 2012, and 2011.

	Number of units	Weighted Average Grant-Date Fair Value
Outstanding at December 31, 2010	-	$ -
Granted	135,870	33.94
Outstanding at December 31, 2011	135,870	33.94
Granted	171,750	41.94
Outstanding at December 31, 2012	307,620	38.40
Granted	244,578	46.54
Outstanding at December 31, 2013	552,198	42.01

Subsequent Event. On January 14, 2014, the Committee made awards to the executive management of the general partner for the 2014 compensation cycle of 111,745 equity-settled performance units under our LTIP that will vest in June 2017.

Director Grants

Starting in 2011, the common units granted to our non-management directors vested immediately at the grant date. The awards granted before 2011 settled with the delivery of common units and were subject to a three-year vesting, without a performance condition, and vested ratably on each anniversary of the grant date. In 2013, the awards granted before 2011 vested.

The following table summarizes activity of the common unit-based awards granted to our Directors for the years ended December 31, 2013, 2012 and 2011 (in units and dollars):

	Number of units	Weighted Average Grant-Date Fair Value
Outstanding at December 31, 2010	39,074	$ 16.12
Granted	10,600	33.53
Vested and paid	(29,843)	22.18
Outstanding at December 31, 2011	19,831	16.31
Granted	9,980	38.72
Vested and paid	(25,311)	23.86
Outstanding at December 31, 2012	4,500	23.51
Granted	12,780	39.33
Vested and paid	(17,280)	35.21
Outstanding at December 31, 2013	-	-

Subsequent Event. On January 14, 2014, the Committee made awards of 8,740 of our common units (1,748 units to each of our non-management directors). The awards vested immediately at the grant date.

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TRC LTIP – Cash-settled Performance Units

The following table summarizes the cash-settled performance units for the year ended 2013 awarded under the Targa LTIP (in units and millions of dollars):

	Program Year				
	2010 Plan	**2011 Plan**	**2012 Plan**	**2013 Plan**	**Total**
Units outstanding January 1, 2013	306,253	122,550	140,820	-	569,623
Granted	-	3,000	3,200	145,970	152,170
Vested and paid	(305,853)	-	-	-	(305,853)
Forfeited	(400)	(680)	(1,560)	(1,010)	(3,650)
Units outstanding December 31, 2013	-	124,870	142,460	144,960	412,290
Calculated fair market value as of December 31, 2013		$ 10.6	$ 10.4	$ 7.6	$ 28.6
Current liability		$ 8.7	$ -	$ -	$ 8.7
Long-term liability		-	4.9	1.0	5.9
Liability as of December 31, 2013		$ 8.7	$ 4.9	$ 1.0	$ 14.6
To be recognized in future periods		$ 1.9	$ 5.5	$ 6.6	$ 14.0
Vesting date		June 2014	June 2015	June 2016	

The remaining weighted average recognition period for the unrecognized compensation cost is approximately 1.8 years.

2010 TRC Stock Incentive Plan

The Targa Plan allows for the grant of (i) incentive stock options qualified as such under U.S. federal income tax laws (“Incentive Options”), (ii) stock options that do not qualify as incentive options (“Non-statutory Options,” and together with Incentive Options, “Options”), (iii) stock appreciation rights (“SARs”) granted in conjunction with Options or Phantom Stock Awards, (iv) restricted stock awards (“Restricted Stock Awards”), (v) phantom stock awards (“Phantom Stock Awards”), (vi) bonus stock awards, (vii) performance unit awards, or (viii) any combination of such awards (collectively referred to a “Awards”).

Restricted Stock – Total shares authorized under this plan are 5,000,000. Restricted stock entitles the recipient to cash dividends. Dividends on unvested restricted stock will be accrued when declared and recorded as short-term or long-term liabilities, dependent on the time remaining until payment of the dividends. The following table summarizes the restricted stock awards in shares and in dollars for the years indicated:

	Number of shares	Weighted-average Grant-Date Fair Value
Outstanding at December 31, 2010 (1)	1,350,000	$ 22.00
Granted (2)	84,220	33.39
Outstanding at December 31, 2011	1,434,220	22.67
Granted (2)	91,090	42.50
Forfeited	(8,930)	23.99
Vested (3)	(805,350)	22.00
Outstanding at December 31, 2012	711,030	25.95
Granted (2)	30,623	57.59
Forfeited	(2,740)	27.28
Vested (3)	(534,940)	22.00
Outstanding at December 31, 2013	203,973	41.05

(1) These awards were issued in conjunction with the Targa IPO and vest over a three year period at 60% in 2012 and the remaining 40% in 2013.
(2) These awards will cliff vest at the end of three years.
(3) Awards vested in 2013 and 2012 were 40% and 60% of the awards issued in conjunction with the Targa IPO, net of forfeitures. Targa repurchased 169,159 and 197,731 shares from employees at $79.01 and $47.88 per share in 2013 and 2012 to satisfy the employees' minimum statutory tax withholdings on the vested awards. The repurchased shares are recorded in treasury stock at cost.

The compensation expense of the restricted stocks was calculated based on the fair value of the stock at the grant date.

Restricted Stock Units ("RSUs") – RSUs are similar to restricted stock, except that shares of common stock are not issued until the RSUs vest. The following table summarizes the restricted stock awards in shares and in dollars for the years indicated.

	Number of shares	Weighted-average Grant-Date Fair Value
Outstanding at December 31, 2012	-	$ -
Granted	55,790	69.90
Forfeited	(240)	67.07
Outstanding at December 31, 2013	55,550	69.92

Subsequent Event. On January 14, 2014, the compensation committee (the "Committee") made restricted stock awards of 22,017 shares to executive management under the TRC Plan for the 2014 compensation cycle that will cliff vest in three years from the grant date.

The following table summarizes the compensation expenses under the various compensation plans recognized for the years indicate:

	2013	2012	2011
LTIP - Equity-Settled Performance Units	$ 5.5	$ 3.1	$ 1.0
Director Grants	0.5	0.5	0.5
Allocated from Targa			
TRC LTIP - Cash-Settled Performance Units	21.9	14.2	13.3
2010 TRC Stock Incentive Plan - Restricted Stock	6.3	13.7	13.4
2010 TRC Stock Incentive Plan - Restricted Stock Units	0.4	-	-

The table below summarizes the unrecognized compensation expenses and the approximate remaining weighted average vesting periods related to our various compensation plans as of December 31, 2013:

	December 31, 2013	Weighted Average Remaining Vesting Period
	(In millions)	(In years)
LTIP Equity-Settled Performance Units	$ 16.3	2.0
2010 TRC Stock Incentive Plan - Restricted Stock	3.3	1.6
2010 TRC Stock Incentive Plan - Restricted Stock Units	3.6	2.8

The total fair values of share-based awards on the dates they vested are as follows:

	2013	2012	2011
TRC LTIP - Cash-Settled Performance Units	$ 25.2	$ 22.2	$ 5.5
Director Grants	0.7	1.0	1.0
2010 TRC Stock Incentive Plan - Restricted Stock (1)	42.2	40.3	-
Accrued dividends settled	2.4	2.0	-

(1) Targa recognized $1.6 million and $1.3 million in tax benefits for 2013 and 2012 that were associated with the vesting of the 40% and 60% restricted stock related to Targa IPO.

Targa 401(k) Plan

Targa has a 401(k) plan whereby it matches 100% of up to 5% of an employee’s contribution (subject to certain limitations in the plan). Targa also contributes an amount equal to 3% of each employee’s eligible compensation to the plan as a retirement contribution and may make additional contributions at our sole discretion. All Targa contributions are made 100% in cash. Targa made contributions to the 401(k) plan totaling $9.6 million, $8.7 million and $7.8 million during 2013, 2012 and 2011.

Note 21 — Segment Information

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

Our Gathering and Processing division includes assets used in the gathering of natural gas produced from oil and gas wells and processing this raw natural gas into merchantable natural gas by extracting NGLs and removing impurities. The Field Gathering and Processing segment's assets are located in North Texas and the Permian Basin of West Texas and New Mexico. With the Badlands acquisition on December 31, 2012, this segment's assets now include the Badlands crude oil and natural gas gathering, terminaling and processing assets in North Dakota. Because the acquisition closed on December 31, 2012, Badlands had no operational impact for 2012. The Coastal Gathering and Processing segment's assets are located in the onshore and near offshore regions of the Louisiana Gulf Coast and the Gulf of Mexico.

Our Logistics and Marketing division is also referred to as our Downstream Business. Our Downstream Business includes all the activities necessary to convert mixed NGLs into NGL products and provides certain value added services such as storing, terminaling, distributing and marketing of NGLs, refined petroleum products and crude oil. It also includes certain natural gas supply and marketing activities in support of our other operations, as well as transporting natural gas and NGLs.

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

Our Marketing and Distribution segment covers activities required to distribute and market raw and finished NGLs and all natural gas marketing activities. It includes (1) marketing our own NGL production and purchasing NGL products 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; providing propane, butane and services to LPG exporters; and (4) marketing natural gas available to us from our Gathering and Processing division and the purchase and resale and other value added activities related to third-party natural gas in selected United States markets.

Other contains the results of our commodity hedging activities included in operating margin. Eliminations of inter-segment transactions are reflected in the corporate and eliminations column.

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Our reportable segment information is shown in the following tables:

	Year Ended December 31, 2013						
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Total
Revenues							
Sales of commodities	$ 188.8	$ 305.0	$ 140.5	$ 5,319.3	$ 21.4	$ 0.1	$ 5,975.1
Fees from midstream services	112.8	33.4	216.0	217.1	-	(0.1)	579.2
Business interruption insurance	1.1	0.2	-	0.6	-	-	1.9
	302.7	338.6	356.5	5,537.0	21.4	-	6,556.2
Intersegment revenues							
Sales of commodities	1,218.9	642.2	3.9	478.6	-	(2,343.6)	-
Fees from midstream services	3.4	1.0	176.5	29.8	-	(210.7)	-
	1,222.3	643.2	180.4	508.4	-	(2,554.3)	-
Revenues	$ 1,525.0	$ 981.8	$ 536.9	$ 6,045.4	$ 21.4	$ (2,554.3)	$ 6,556.2
Operating margin	$ 270.5	$ 85.4	$ 282.3	$ 141.9	$ 21.4	$ -	$ 801.5
Other financial information:							
Total assets	$ 3,200.7	$ 383.8	$ 1,503.6	$ 756.1	$ 5.1	$ 122.1	$ 5,971.4
Capital expenditures	$ 557.8	$ 20.6	$ 444.7	$ 6.3	$ -	$ 5.1	$ 1,034.5

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	Year Ended December 31, 2012						
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Total
Revenues							
Sales of commodities	$ 172.7	$ 240.6	$ 184.4	$ 4,890.2	$ 41.1	$ -	$ 5,529.0
Fees from midstream services	39.5	23.6	170.7	120.9	-	(0.1)	354.6
	212.2	264.2	355.1	5,011.1	41.1	(0.1)	5,883.6
Intersegment revenues							
Sales of commodities	1,150.7	701.1	1.8	565.0	-	(2,418.6)	-
Fees from midstream services	1.3	0.1	106.5	32.0	-	(139.9)	-
	1,152.0	701.2	108.3	597.0	-	(2,558.5)	-
Revenues	$ 1,364.2	$ 965.4	$ 463.4	$ 5,608.1	$ 41.1	$ (2,558.6)	$ 5,883.6
Operating margin	$ 231.2	$ 115.1	$ 188.3	$ 116.0	$ 41.1	$ -	$ 691.7
Other financial information:							
Total assets	$ 2,797.9	$ 414.1	$ 1,100.9	$ 548.6	$ 34.4	$ 129.8	$ 5,025.7
Capital expenditures	$ 222.1	$ 9.4	$ 359.0	$ 12.3	$ -	$ 13.9	$ 616.7
Business acquisitions	970.4	$ 25.8	$ -	$ -	$ -	$ -	$ 996.2

	Year Ended December 31, 2011						
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	Total
Revenues							
Sales of commodities	$ 184.9	$ 325.7	$ 43.2	$ 6,209.9	$ (37.6)	$ -	$ 6,726.1
Fees from midstream services	27.5	19.8	130.0	83.8	-	(0.1)	261.0
	212.4	345.5	173.2	6,293.7	(37.6)	(0.1)	6,987.1
Intersegment revenues							
Sales of commodities	1,428.4	952.9	1.0	636.5	-	(3,018.8)	-
Fees from midstream services	1.1	0.4	89.3	36.6	-	(127.4)	-
	1,429.5	953.3	90.3	673.1	-	(3,146.2)	-
Revenues	$ 1,641.9	$ 1,298.8	$ 263.5	$ 6,966.8	$ (37.6)	$ (3,146.3)	$ 6,987.1
Operating margin	$ 287.9	$ 174.3	$ 123.1	$ 113.4	$ (37.6)	$ -	$ 661.1
Other financial information:							
Total assets	$ 1,666.2	$ 427.5	$ 775.4	$ 650.5	$ 51.9	$ 86.5	$ 3,658.0
Capital expenditures	$ 167.5	$ 12.8	$ 147.4	$ 3.5	$ -	$ 2.3	$ 333.5
Business acquisitions	$ -	$ -	$ 156.5	$ -	$ -	$ -	$ 156.5

The following table shows our consolidated revenues by product and service for the periods presented:

	2013	2012	2011
Sales of commodities			
Natural gas	$ 1,224.7	$ 926.9	$ 1,120.7
NGL	4,470.9	4,265.7	5,496.9
Condensate	121.8	114.1	103.0
Petroleum products	136.0	180.1	43.1
Derivative activities	21.7	42.2	(37.6)
	5,975.1	5,529.0	6,726.1
Fees from midstream services			
Fractionating and treating	152.0	115.6	86.7
Storage, terminaling, transportation and export	275.5	159.2	110.4
Gathering and processing	114.1	45.0	33.1
Other	37.6	34.8	30.8
	579.2	354.6	261.0
Business interruption insurance	1.9	-	-
Total revenues	$ 6,556.2	$ 5,883.6	6,987.1

The following table shows a reconciliation of operating margin to net income for the periods presented:

	2013	2012	2011
Reconciliation of operating margin to net income:			
Operating margin	$ 801.5	$ 691.7	$ 661.1
Depreciation and amortization expense	(271.6)	(197.3)	(178.2)
General and administrative expense	(143.1)	(131.6)	(127.8)
Interest expense, net	(131.0)	(116.8)	(107.7)
Income tax expense	(2.9)	(4.2)	(4.3)
Other, net	5.7	(38.6)	2.4
Net income	$ 258.6	$ 203.2	$ 245.5

Note 22 — Selected Quarterly Financial Data (Unaudited)

Our results of operations by quarter for the years ended December 31, 2013 and 2012 were as follows:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
	(In millions, except per unit amounts)				
2013					
Revenues	$ 1,397.8	$ 1,441.6	$ 1,556.9	$ 2,159.9	$ 6,556.2
Gross margin	260.3	265.2	297.1	355.1	1,177.7
Operating income	76.2	63.2	91.0	146.8	377.2
Net income	45.3	32.7	65.0	115.6	258.6
Net income allocable to limited partners	16.1	1.2	31.6	77.1	126.0
Net income per limited partner unit					
- basic	$ 0.16	$ 0.01	$ 0.30	$ 0.70	$ 1.19
- diluted	$ 0.16	$ 0.01	$ 0.30	$ 0.70	$ 1.19
2012					
Revenues	$ 1,645.5	$ 1,318.4	$ 1,392.9	$ 1,526.8	$ 5,883.6
Gross margin	261.4	243.8	239.9	259.6	1,004.7
Operating income	110.2	85.5	61.3	85.9	342.9
Net income	81.8	54.7	28.1	38.6	203.2
Net income allocable to limited partners	56.0	31.4	7.5	13.0	107.9
Net income per limited partner unit					
- basic	$ 0.64	$ 0.35	$ 0.08	$ 0.14	$ 1.20
- diluted	$ 0.63	$ 0.35	$ 0.08	$ 0.14	$ 1.20

Exhibit 12.1

Targa Resources Partners LP
Computation of Ratio of Earnings to Fixed Charges

	Years Ended December 31,				
	2013	**2012**	**2011**	**2010**	**2009**
			(In millions)		
Pre-tax income from continuing operations	$ 261.5	$ 207.4	$ 249.8	$ 138.0	$ 8.4
Fixed charges:					
Interest expense and amortization of debt issuance costs	131.0	116.8	107.7	110.9	159.8
Capitalized interest	28.0	13.6	3.4	1.3	0.7
Operating lease payments	7.8	5.4	4.7	4.6	4.5
Total fixed charges	166.8	135.8	115.8	116.8	165.0
Amortization of capitalized interest	1.7	0.7	0.2	0.1	0.1
Equity earnings in unconsolidated investment	(14.8)	(1.9)	(8.8)	(5.4)	(5.0)
Distributions from unconsolidated investment	12.0	2.3	8.3	8.7	5.1
Capitalized interest	(28.0)	(13.6)	(3.4)	(1.3)	(0.7)
Pre-tax income from continuing operations plus fixed charges	$ 399.2	$ 330.7	$ 361.9	$ 256.9	$ 172.9
Ratio of earnings to fixed charges	2.4	2.4	3.1	2.2	1.0

Exhibit 21.1

Targa Resources Partners LP Subsidiary List

Entity Name	Jurisdiction of Formation
Cedar Bayou Fractionators, L.P.	Delaware
DEVCO Holdings LLC	Delaware
Downstream Energy Ventures Co., L.L.C.	Delaware
Gulf Coast Fractionators	Texas
Targa Badlands LLC	Delaware
Targa Canada Liquids Inc.	British Columbia
Targa Capital LLC	Delaware
Targa Cogen LLC	Delaware
Targa Downstream LLC	Delaware
Targa Gas Marketing LLC	Delaware
Targa Gas Pipeline LLC	Delaware
Targa Gas Processing LLC	Delaware
Targa Intrastate Pipeline LLC	Delaware
Targa Liquids Marketing and Trade LLC	Delaware
Targa Louisiana Intrastate LLC	Delaware
Targa MLP Capital LLC	Delaware
Targa Midstream Services LLC	Delaware
Targa NGL Pipeline Company LLC	Delaware
Targa Receivables LLC	Delaware
Targa Resources Operating GP LLC	Delaware
Targa Resources Operating LLC	Delaware
Targa Resources Partners Finance Corporation	Delaware
Targa Sound Terminal LLC	Delaware
Targa Terminals LLC	Delaware
Targa Transport LLC	Delaware
Venice Energy Services Company, L.L.C.	Delaware
Venice Gathering System, L.L.C.	Delaware
Versado Gas Processors, L.L.C.	Delaware
Warren Petroleum Company LLC	Delaware

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S-8 (No.333-149200), Form S-3 (No. 333-187795), and Form S-3/A (No. 333-190231) of Targa Resources Partners LP of our report dated February 14, 2014, relating to the consolidated financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/PricewaterhouseCoopers LLP
Houston, Texas
February 14, 2014

Exhibit 31.1

CERTIFICATION
PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Joe Bob Perkins, certify that:

1. I have reviewed this Annual Report on Form 10-K of Targa Resources Partners LP (the "registrant");

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

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

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

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

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

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

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

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

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

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

Date: February 14, 2014

By: /s/ Joe Bob Perkins
Name: Joe Bob Perkins
Title: Chief Executive Officer of Targa Resources GP LLC,
the general partner of Targa Resources Partners LP
(Principal Executive Officer)

Exhibit 31.2

CERTIFICATION
PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Matthew J. Meloy, certify that:

1. I have reviewed this Annual Report on Form 10-K of Targa Resources Partners LP (the “registrant”);

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

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

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

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

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

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

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

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

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

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

Date: February 14, 2014

By: /s/ Matthew J. Meloy
Name: Matthew J. Meloy
Title: Senior Vice President, Chief Financial Officer and Treasurer
of Targa Resources GP LLC, the general partner of Targa Resources Partners LP
(Principal Financial Officer)

Exhibit 32.1

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

In connection with the Annual Report on Form 10-K of Targa Resources Partners LP (the "Partnership") for the year ended 2013 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Joe Bob Perkins, as Chief Executive Officer of Targa Resources GP LLC, the general partner of the Partnership, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

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

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

By: /s/ Joe Bob Perkins
Name: Joe Bob Perkins
Title: Chief Executive Officer of Targa Resources GP LLC,
the general partner of Targa Resources Partners LP

Date: February 14, 2014

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

Exhibit 32.2

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

In connection with the Annual Report on Form 10-K of Targa Resources Partners LP (the “Partnership”) for the year ended 2013 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), Matthew J. Meloy, as Chief Financial Officer of Targa Resources GP LLC, the general partner of the Partnership, hereby certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

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

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

By: /s/ Matthew J. Meloy
Name: Matthew J. Meloy
Title: Senior Vice President, Chief Financial Officer and Treasurer
of Targa Resources GP LLC, the general partner of
Targa Resources Partners LP

Date: February 14, 2014

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