Targa Resources Corp.
Form 10-K
February 19, 2013

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

FORM 10-K

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

For the fiscal year ended December 31, 2012

or

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

For the transition period from _____ to _____

Commission File Number: 001-34991

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

Delaware (State or other jurisdiction of incorporation or organization)	20-3701075 (I.R.S. Employer Identification No.)
1000 Louisiana St, Suite 4300, Houston, Texas (Address of principal executive offices)	77002 (Zip Code)

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

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

Title of each class	Name of each exchange on which registered
Common Stock	New York Stock Exchange

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes R No £

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 stock held by non-affiliates of the registrant was approximately $1,301.1 million on June 29, 2012, based on $42.70 per share, the closing price of the common stock as reported on the New York Stock Exchange (NYSE) on such date.

As of February 15, 2013, there were 42,331,085 shares of the registrant's common stock, $0.001 par value, outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None

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CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

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

- the Partnership's and our ability to access the debt and equity markets, which will depend on general market conditions and the credit ratings for our debt obligations;
- the amount of collateral required to be posted from time to time in the Partnership's transactions;
- the Partnership's success in risk management activities, including the use of derivative instruments to hedge commodity risks;
- the level of creditworthiness of counterparties to 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") and other commodity prices, interest rates and demand for the Partnership's services;
- weather and other natural phenomena;
- industry changes, including the impact of consolidations and changes in competition;
- the Partnership's ability to obtain necessary licenses, permits and other approvals;
- the level and success of oil and natural gas drilling around the Partnership's assets, its success in connecting natural gas supplies to its gathering and processing systems and NGL supplies to its logistics and marketing facilities and the Partnership's success in connecting its facilities to transportation and markets;
- the Partnership's and our ability to grow through acquisitions or internal growth projects and the successful integration and future performance of such assets;

- 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.

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

Bbl	Barrels (equal to 42 U.S. gallons)
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
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

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PART I

Item 1. Business.

Overview

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

On December 10, 2010, we completed an initial public offering ("IPO") of common shares in the Company. In the IPO, the selling shareholders, including a member of our senior management, sold 18,831,250 common shares at a price of $22.00 per share. We did not receive any proceeds from the sale of shares by the selling shareholders. On completion of the IPO, there were 42,292,348 shares outstanding.

Financial Presentation

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

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

- noncontrolling interest in the Partnership;
- our separate debt obligations;
- certain general and administrative costs applicable to us as a public company;
- federal income taxes; and
- certain non-operating assets and liabilities that we retained.

Overview of the Business of Targa Resources Corp.

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

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At February 15, 2013, our interests in the Partnership consist of the following:

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

all of the outstanding IDRs; and

12,945,659 of the 101,788,617 outstanding common units of the Partnership, representing a 12.7% limited partnership interest.

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

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

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

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

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

We are party to an Omnibus Agreement with the Partnership that governs the relationship regarding certain reimbursement and indemnification matters. The Partnership agreement will govern these matters after the Omnibus Agreement expires on April 30, 2013. So long as our only cash generating asset is our interests in the Partnership, we will continue to allocate to the Partnership substantially all of our general and administrative costs other than our direct costs of being a reporting company. See "Item 13. Certain Relationships and Related Transactions, and Director Independence—Omnibus Agreement."

We employ 1,192 people. See "Employees." The Partnership does not have any employees to carry out its operations.

Overview of the Business of the Partnership

We formed the Partnership in October 2006 to own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets. The Partnership is a leading provider of midstream natural gas, NGL, terminaling and crude oil gathering services in the United States. It is engaged in the business of:

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

The Partnership operates in two primary divisions: (i) Gathering and Processing, consisting of two reportable segments—(a) Field Gathering and Processing and (b) Coastal Gathering and Processing; and (ii) Logistics and Marketing, consisting of two reportable segments—(a) Logistics Assets and (b) Marketing and Distribution.

Acquisitions from Targa

From 2007 through 2010, the Partnership acquired most of its operating businesses in a series of acquisitions from us with an aggregate purchase price of approximately $3.1 billion. The businesses include:

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- In February 2007, the Partnership acquired certain natural gas gathering, processing and treating assets in the Fort Worth Basin / Bend Arch in North Texas and their operations collectively referred to as the “North Texas System;”

- In October 2007, the Partnership acquired certain natural gas gathering, processing and treating assets in West Texas and their operations collectively referred to as “SAOU;”

- In October 2007, the Partnership acquired certain natural gas gathering, processing and treating assets in Southwest Louisiana and their operations collectively referred to as “LOU;”

- In September 2009, the Partnership acquired our NGL business consisting of fractionation facilities, storage and terminaling facilities, low sulfur natural gasoline treating facilities, pipeline transportation and distribution assets, propane storage, truck terminals and NGL transport assets and their operations collectively referred to as the Logistics and Marketing division or the “Downstream Business;”

- In April 2010, the Partnership acquired certain natural gas gathering and processing assets which serve production from the Louisiana Gulf Coast and their operations collectively referred to as the “Coastal Straddles;”

- In April 2010, the Partnership acquired certain natural gas gathering and processing systems, processing plants and related assets in West Texas and their operations collectively referred to as “Sand Hills;”

- In August 2010, the Partnership acquired our 63% ownership interest in Versado Gas Processors, L.L.C. which conducts a natural gas gathering and processing business in New Mexico, collectively referred to as “Versado;” and

- In September 2010, the Partnership acquired our 77% ownership interest in Venice Energy Services Company, L.L.C., a joint venture that owns and operates a natural gas gathering and processing business in Louisiana consisting of a coastal straddle plant and their operations and a wholly-owned subsidiary that owns and operates an offshore gathering system and related assets (collectively, “VESCO”) that serve production from the Gulf of Mexico shelf and deepwater.

For a detailed description of these assets, please see “— The Partnership’s Business Operations.”

Acquisitions from Third Parties

While the Partnership’s growth through 2010 was primarily driven by the implementation of a dropdown strategy, it also had a record of successful third-party acquisitions. During 2011 and 2012, the Partnership closed the following acquisitions:

Badlands

On December 31, 2012, the Partnership 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 $975.8 million subject to customary purchase price adjustments and a contingent payment of $50 million that is conditioned upon aggregate crude oil gathering volumes exceeding certain thresholds by mid-2014. The business is located in the Williston Basin in the McKenzie, Dunn and Mountrail counties of North Dakota and includes approximately 155 miles of crude oil gathering pipelines. The acquired business has combined crude oil operational storage capacity of 70,000 barrels with a combined estimated throughput of 32,000 barrels per day. It also includes approximately 95 miles of natural gas gathering pipelines and a 20 MMcf/d natural gas processing plant with an expansion underway to increase capacity to 40 MMcf/d. As of December 31, 2012, the system had approximately 260,000 acres dedicated for crude oil gathering and over 100,000 acres dedicated for natural gas gathering. We are actively pursuing gathering opportunities such that we expect additional acreage dedications from producers active in the Bakken Shale as we expand our operations. As this acquisition closed on December 31, 2012, it had no impact on the Partnership's results of operations for 2012, other than transaction costs related to the acquisition. See Note 4 in our "Consolidated Financial Statements" for pro forma financial information related to the Partnership's Badlands acquisition.

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Other Acquisitions

- In March 2011, the Partnership 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 million. The Channelview Terminal, with storage capacity of 544,000 barrels, can handle multiple grades of blend stocks, petroleum products and crude oil and has potential for expansion, as well as integration with the Partnership's other logistics operations.

- In September 2011, the Partnership acquired refined petroleum products and crude oil storage and terminaling facilities in two separate transactions. The facility on the Hylebos Waterway in the Port of Tacoma, Washington (the "Sound Terminal") has 758,000 barrels 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 (the "Baltimore Terminal") has approximately 505,000 barrels 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.

- In July 2012, the Partnership acquired the Big Lake gas processing plant in Lake Charles, Louisiana, with a gross processing capacity of 200 MMcf/d.

- In December 2012, the Partnership acquired additional property on the Houston Ship Channel ("Targa Patriot Marine Terminal" or "Patriot Terminal"). The Partnership's initial investment including the acquisition of the property and initial dock upgrades will be approximately $25 million. While not currently operational, the acquisition of the Patriot Terminal provides expansion potential for both our Petroleum Logistics business and propane/butane export capabilities.

The Partnership has funded all acquisitions from Targa and third parties using earnings from operations, proceeds of equity offerings, borrowings under its credit facilities and note issuances. We expect that acquisitions of third-party businesses and assets will continue to be a significant component of the Partnership's growth strategy.

Organic Growth Projects

In addition to acquiring businesses and assets from us and third parties, the Partnership has successfully completed both large and small organic growth projects associated with its existing assets and expects to continue to do so in the future. These projects have involved growth capital expenditures of approximately $1 billion since 2007 and include the following projects completed in 2012:

- Benzene treating project. A new treater was constructed which operates in conjunction with the Partnership's existing low sulfur natural gasoline ("LSNG") facility at Mont Belvieu and is designed to reduce benzene content of natural gasoline to meet new, more stringent environmental standards. The gross cost was approximately $40 million and was completed in the first quarter of 2012.

- Gulf Coast Fractionators expansion. In the second quarter of 2012, Gulf Coast Fractionators ("GCF"), a partnership with Phillips 66 and Devon Energy Corporation, in which the Partnership owns a 38.8% interest, completed an expansion to increase the capacity of its NGL fractionation facility in Mont Belvieu. The gross cost was approximately $92 million (the Partnership's net cost was approximately $35 million) for an estimated ultimate capacity of approximately 145 MBbl/d.

The Partnership has the following major organic growth projects either underway or announced, which it estimates will require approximately $1.3 billion in future growth capital expenditures through 2014:

- Cedar Bayou Fractionators expansion. The Partnership is currently constructing approximately 100 MBbl/d of additional fractionation capacity ("Train 4") at its 88% owned Cedar Bayou Fractionator ("CBF") in Mont Belvieu for an estimated gross cost of $385 million. The expected start-up of the Train 4 facilities is in the second quarter of 2013.

- North Texas Longhorn plant. The Partnership has commenced spending associated with a new 200 MMcf/d cryogenic processing plant for its North Texas System, with an expected completion in third quarter 2013, subject to regulatory approvals, and an estimated capital investment of approximately $150 million for the plant and associated projects.

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- International export projects. Construction is underway to expand the Partnership's propane and butane international export capacity. The Partnership expects to invest a total of approximately $480 million in connection with the expanded project to improve and expand its Mont Belvieu complex and existing import/export marine terminals at Galena Park. The anticipated completion date for the initial portion of the project is in the third quarter of 2013, and we expect to complete the expanded portion of the project in the third quarter of 2014.

As mentioned previously, in December 2012, the Partnership acquired the Targa Patriot Marine Terminal near its existing marine terminal in Galena Park. The Partnership's investment, including acquisition of the property and initial dock upgrades, will be approximately $25 million. Plans are being developed to utilize the facility for petroleum products and/or propane/butane exports.

- Petroleum logistics terminal expansions. The Partnership has started projects to expand the capacity and capability of the three refined products terminals that it acquired in 2011. The Partnership expects to invest approximately $105 million on these projects.

- SAOU High Plains plant. The Partnership has commenced spending associated with 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. The Partnership expects to invest an estimated $225 million for the plant and associated projects.

- Badlands expansion. The Partnership has announced preliminary plans to invest over $250 million during 2013 to support additional infrastructure necessary to meet producer activity at its Badlands gathering systems and facilities in North Dakota.

Growth Drivers

The Partnership believes its near-term growth will be driven by its significant organic growth investments as well as strong supply and demand fundamentals for the Partnership's existing businesses. The Partnership's believes that its assets are not easily duplicated and are located in active producing areas and near key NGL markets and logistics centers. Over the longer term, we expect the Partnership's growth will continue to be driven by shale plays and by the deployment of shale exploration and production technologies in both liquids-rich natural gas and crude oil resource plays.

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

We believe that the current levels of oil, condensate and NGL prices and the forecast prices for these energy commodities have caused producers in and around our natural gas gathering and 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 Trend, 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, which are accessible by the Sand Hills system, and 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.

Producer activity and resulting NGL supplies from areas rich in oil, condensate and NGLs are currently generating high demand for the Partnership's fractionation services at the Mont Belvieu market hub. As a result, fractionation volumes have recently increased to near existing capacity. Even as additional fractionation capacity comes on-line beginning in 2013, there has been limited incremental supply of fractionation services in the area. These strong supply and demand fundamentals have resulted in long-term, "take-or-pay" contracts for existing capacity and support the construction of new fractionation capacity, such as the Partnership's CBF and GCF expansion projects. We are continuing to see rates for fractionation services increase. The higher volumes of fractionated NGLs should also result in increased demand for other related fee-based services provided by the Downstream Business.

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As domestic producers have focused their drilling in 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, NGLs requiring transportation and fractionation to market hubs is expected to continue. The domestic demand for NGL components such as propane and butane have remained relatively flat compared to growing demand in other parts of the world while certain key global production areas are realizing less LPG production. The excess supply and globally lower relative production cost in the U.S. has caused prices for these products to be favorably priced compared to other world markets, creating export opportunities to higher price markets. The Partnership's integrated Mont Belvieu and Galena Park Terminal assets allow us to provide the raw product, fractionation, storage, interconnected terminalling, refrigeration, pumping and ship loading capabilities to support exports. The Partnership is currently loading small and medium sized export vessels and has expansions underway to be able to support larger vessels in addition to our current activity.

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

The Partnership is actively pursuing natural gas gathering and processing and NGL fractionation opportunities associated with liquids-rich natural gas from shale and other resource plays, such as portions of the Barnett Shale and the Eagle Ford Shale, 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 the Partnership's leadership position in the Downstream Business, which includes its fractionation services, provides it with a competitive advantage relative to other gathering and processing companies without these capabilities.

Bakken Shale / Three Forks opportunities

The Bakken Shale and Three Forks areas of the Williston Basin are projected to be among the fastest growing crude oil basins in the world. As producers have increased their knowledge of the basin, they have increased drilling efficiencies and unlocked more value from their acreage. Much of the current oil production is transported by truck from the wells to terminals to be loaded onto rail cars or injected into pipelines. The transportation costs from trucking are higher than from gathering pipelines, giving the producers an economic incentive to pay for gathering services. Similarly, much of the current gas production is being flared, giving producers an incentive to pay for gathering and processing services. The Partnership's recently acquired assets in the heart of the Bakken play should allow it to participate in the infrastructure build out in return for fee-based revenue to gather crude oil, or gather and process gas, from the wellhead to various takeaway options. There is a significant amount of uncommitted acreage in proximity to the Partnership's system which should provide further opportunities to enhance medium and long-term growth.

Potential third party acquisitions

While the Partnership's growth through 2010 was primarily driven by the implementation of a focused drop down strategy, its management team also has a record of successful third party acquisitions. Since the Partnership's formation, its strategy has included approximately $5.3 billion in acquisitions and growth capital expenditures of which $1.2 billion was third-parties. We expect that third-party acquisitions will continue to be a significant focus of the Partnership's growth strategy.

Competitive Strengths and Strategies

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

Strategically located gathering and processing asset base

The Partnership's gathering and processing businesses are predominantly located in active and growth oriented oil and gas producing basins. Activity in the shale resource plays underlying 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 the Partnership's gathering and processing systems and from oil wells in the Bakken and Three Forks plays which are accessible by our Badlands business in North Dakota.

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Leading fractionation position

The Partnership is one of the largest fractionators of NGLs in the Gulf Coast. Its primary fractionation assets are located in Mont Belvieu, Texas and Lake Charles, Louisiana, which are key market centers for NGLs and are located at the intersection of NGL infrastructure including a stream of mixed NGL (“Mixed NGLs” or “Y-grade”) supply pipelines, storage, takeaway pipelines and other transportation infrastructure. The Partnership’s assets are also located near and connected to key consumers of NGL products including the petrochemical and industrial markets. The location and interconnectivity of the assets are not easily replicated, and the Partnership has sufficient additional capability to expand its capacity. The management has extensive experience in operating these assets and in permitting and building new midstream assets.

Comprehensive package of midstream services

The Partnership provides a comprehensive package of services to natural gas and crude oil producers, including: natural gas gathering, compression, treating, processing and selling; storing, fractionating, treating, and selling NGLs, NGL products, refined petroleum products and crude; and transporting natural gas, NGLs and NGL products. 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 and commercial markets. We believe that the Partnership’s ability to provide these integrated services provides an advantage in competing for new supplies of natural gas because it 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, 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, the barriers to enter the midstream sector on a scale similar to ours are reasonably high.

High quality and efficient assets

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

In addition to routine annual maintenance expenses, the Partnership’s maintenance capital expenditures have averaged $69.4 million per year over the last three years. We believe that the Partnership’s assets are well-maintained and anticipate that a similar level of maintenance capital expenditures will be sufficient for 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

The Partnership maintains gathering and processing positions in strategic oil and gas producing areas across multiple oil and gas basins and provides services under attractive contract terms to a diverse mix of customers across its areas of operations. Consequently, the Partnership is not dependent on any one oil and gas basin or customer. The gathering and processing contract portfolio has attractive rate and term characteristics. The Partnership's NGL Logistics and Marketing assets are typically located near key market hubs and near important 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. The logistics contract portfolio, largely fee-based, has attractive rate and term characteristics. Given the higher rates for logistics assets contracts that are being renewed, the new projects underway, the long-term nature of many of the renewed and new contracts and continuing strong supply and demand fundamentals for this business, we expect an increasing percentage of the Partnership's cash flows to be fee-based. The expected growth of the fee-based Badlands business in North Dakota would also contribute to increasing fee-based cash flow.

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Financial flexibility

The Partnership has historically maintained a conservative leverage ratio and, ample liquidity and have funded its growth investments with a mix of equity and debt over time. The Partnership has also reduced the impact of commodity price volatility by hedging the commodity price risk associated with a portion of its expected natural gas, NGL and condensate equity volumes. Maintaining a disciplined approach regarding the Partnership's leverage ratio and, liquidity and mitigating commodity price volatility allow it to be flexible in its long term growth strategy and enable it to pursue strategic acquisitions and large growth projects.

Experienced and long-term focused management team

The executive management team which formed Targa Resources Inc. in 2004 and continues to manage Targa and the Partnership today possesses breadth and depth of combined experience working in the midstream natural gas and energy business. Other officers and key operational, commercial and financial employees provide significant experience in the industry and with the Partnership's assets and businesses.

Attractive cash flow characteristics

We believe the Partnership's strategy, combined with its high-quality asset portfolio and strong industry fundamentals, allows the Partnership to generate attractive cash flows. Geographic, business and customer diversity enhances the Partnership's cash flow profile. The Partnership's Gathering and Processing division has a favorable contract mix that is primarily percent-of-proceeds, but also has increasing fee-based revenues from natural gas treating fees and crude oil gathering in its recently acquired Bakken Shale midstream assets in the Partnership's Field Gathering and Processing segment, and hybrid or percent-of-liquids contracts in the Partnership's Coastal Gathering and Processing segment. The Partnership's favorable contract mix, along with its long-term commodity hedging program, serves to mitigate the impact of commodity price movements on cash flow. Furthermore, in the Coastal Gathering and Processing Segment, the Partnership can access additional processable gas supplies under keep-whole contracts, which benefit from an environment of low gas prices relative to NGLs and crude oil.

The Partnership has hedged the commodity price risk associated with a portion of its expected natural gas equity volumes through 2015 and its NGL and condensate equity volumes through 2014 by entering into financially settled derivative transactions including swaps and purchased puts (or floors). The primary purpose of the Partnership's commodity risk management activities is to hedge its exposure to price risk and to mitigate the impact of fluctuations in commodity prices on cash flow. The Partnership has intentionally tailored its hedges to approximate specific NGL products and to approximate its actual NGL and residue natural gas delivery points. The Partnership intends to continue to manage its exposure to commodity prices by entering into similar hedge transactions as market conditions permit. The Partnership also monitors and manages its inventory levels with a view to mitigate losses related to downward price exposure.

Asset base well-positioned for organic growth

We believe that the Partnership's asset platform and strategic locations allow it to maintain and potentially grow its volumes and related cash flows as its 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 the Partnership's assets provides it with access to stable natural gas and crude oil supplies and proximity to end-use markets and liquid market hubs while positioning it to capitalize on drilling and production activity in those areas. The Partnership's existing infrastructure has the capacity to handle some incremental increases in volumes without significant investments as well as opportunities to leverage existing assets with meaningful expansions. We believe that as domestic supply and demand for natural gas, crude oil and NGLs, and services for each, grows over the long term, the Partnership's infrastructure will increase in value as such infrastructure takes on increasing importance in meeting that growing supply and demand.

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

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Targa has used the Partnership as a growth vehicle to pursue the acquisition and expansion of midstream natural gas, NGL and other complementary energy businesses and assets as evidenced by the Partnership's acquisition of business from us. However, Targa is not prohibited from competing with the Partnership and may evaluate acquisitions and dispositions that do not involve the Partnership. In addition, through the Partnership's relationship with Targa, it has 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.

The Partnership's Challenges

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

- If the Partnership does not successfully integrate assets from acquisitions, including those from the Badlands acquisition, our results of operations and financial condition could be adversely affected.

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

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

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

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

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

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

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

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

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

The Partnership's Business Operations

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

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Gathering and Processing Division

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

The Partnership continually seeks new supplies of natural gas and crude oil, both to offset the natural decline in production from connected wells and to increase throughput volumes. The Partnership obtains additional crude oil and natural gas supply in its operating areas by contracting for production from new wells or by capturing existing production currently gathered by others. Competition for new crude and natural gas supplies is based primarily on location of assets, commercial terms, service levels and access to markets. The commercial terms of crude oil gathering and of natural gas gathering and processing arrangements 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 that the Partnership's extensive asset base and scope of operations in the regions in which it operates provides it with significant opportunities to add both new and existing natural gas and crude oil production to its systems. We believe that the Partnership's size and scope gives it a strong competitive position by placing it in close proximity to a large number of existing and new producing wells in its areas of operations, allowing the Partnership to generate economies of scale and to provide its customers with access to its existing facilities and to multiple end-use markets and market hubs. Additionally, we believe that the Partnership's ability to serve its customers' needs across the natural gas and NGL value chain further augments its ability to attract new customers.

Field Gathering and Processing Segment

Through 2012, the Field Gathering and Processing segment gathered and processed natural gas from the Permian Basin in West Texas and Southeast New Mexico and the Fort Worth Basin, including the Barnett Shale, in North Texas. The natural gas processed in this segment is supplied through the Partnership's gathering systems which, in aggregate, consist of approximately 10,588 miles of natural gas pipelines and include nine owned and operated processing plants. During 2012, the Partnership processed an average of approximately 681.8 MMcf/d of natural gas and produced an average of approximately 82.6 MBbl/d of NGLs.

Beginning in 2013, this segment will also include the operations of the Partnership's Badlands business, which we acquired on December 31, 2012. These assets consist of a crude oil gathering system and two terminals with crude oil operational storage capacity of 70,000 barrels and natural gas gathering and processing operations with a 20 MMcf/d natural gas processing plant, which an expansion underway will increase to 40 MMcf/d.

We believe that the Partnership is well positioned as a gatherer and processor in the Permian, Fort Worth and Williston Basins. The Partnership has a broad geographic scope, covering portions of 47 counties and approximately 18,500 square miles across these basins. We believe that the Partnership's proximity to production and development provides it with a competitive advantage in capturing new supplies of crude and natural gas because of its competitive costs to connect new wells and to process additional natural gas in its existing processing plants. Additionally, because the Partnership operates all of its plants in these regions, it is often able to redirect natural gas among two or more of its processing plants, allowing it to optimize processing efficiency and further improve the profitability of its operations.

The Field Gathering and Processing segment's operations consist of Sand Hills, Versado, SAOU, the North Texas System and the Badlands, each as described below.

Sand Hills

The Sand Hills operations consist of the Sand Hills gathering and processing system and the West Seminole and Puckett gathering systems in West Texas. These systems consist of approximately 1,460 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 180 MMcf/d and residue gas connections to pipelines owned by affiliates of Enterprise Products Partners LP, ONEOK, Inc. and El Paso Corporation.

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Versado

Versado consists of the Saunders, Eunice and Monument gas processing plants and related gathering systems in Southeastern New Mexico. Versado consists of approximately 3,250 miles of natural gas gathering pipelines. The Saunders, Eunice and Monument refrigerated cryogenic processing plants have aggregate processing capacity of 280 MMcf/d (176.4 MMcf/d, net to the Partnership's ownership interest). These plants have residue gas connections to pipelines owned by affiliates of El Paso Corporation, MidAmerican Energy Company and Kinder Morgan Energy Partners, L.P. The Partnership's ownership in Versado is held through Versado Gas Processors, L.L.C., a joint venture that is 63% owned by the Partnership and 37% owned by Chevron U.S.A. Inc.

SAOU

Covering portions of ten counties and approximately 4,000 square miles in West Texas, SAOU includes approximately 1,537 miles of pipelines in the Permian Basin that gather natural gas to the Mertzon, Sterling and Conger processing plants. SAOU is connected to thousands of producing wells and over 840 central delivery points. SAOU has approximately 1,141 miles of low pressure gathering pipelines and approximately 538 miles of high-pressure gathering pipelines to deliver the natural gas to our processing plants. SAOU has 31 compressor stations to inject low pressure gas into the high-pressure pipelines. SAOU's processing facilities include three currently operating refrigerated cryogenic processing plants—the Mertzon, Sterling and Conger plants—which have an aggregate processing capacity of approximately 139 MMcf/d, with an additional 30 MMcf/d being commissioned in the first quarter of 2013. These plants have residue gas connections to pipelines owned by affiliates of ONEOK Inc., El Paso Corporation, Enterprise Partners L.P., Atmos Energy Corporation, Kinder Morgan Energy Partners L.P. and Northern Natural Gas Company.

The Partnership is incurring costs associated with 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.

North Texas System

The North Texas System includes two interconnected gathering systems with approximately 4,340 miles of pipelines, covering portions of 15 counties and approximately 5,700 square miles, 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 Enterprise Products Partners LP, Atmos Energy Corporation, Energy Transfer Fuel LP and Natural Gas Pipeline Company of America LLC.

The Chico gathering system consists of approximately 2,300 miles of primarily low-pressure 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 consists of approximately 2,100 miles of intermediate-pressure gathering pipelines. The pipelines gather 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.

The Partnership is incurring costs associated with a new 200 MMcf/d cryogenic processing plant for its North Texas system, with expected completion in mid-2013, subject to regulatory approvals, to meet increasing production and producer activity in North Texas.

Badlands

The Badlands assets are located in the Williston Basin of the Bakken Shale Play in the McKenzie, Dunn and Mountrail counties of North Dakota and include approximately 155 miles of crude oil gathering pipelines. The business has combined crude oil operational storage capacity of 70,000 barrels. It also includes approximately 95 miles of natural gas gathering pipelines and a 20 MMcf/d natural gas processing plant with an expansion underway to increase its capacity to 40 MMcf/d. As this acquisition closed on December 31, 2012, it had no impact on our operations for the year then ended. The system spans approximately 260,000 acres dedicated for crude oil gathering and over 100,000 acres dedicated for natural gas gathering.

The following table lists the Field Gathering and Processing segment's processing plants and related volumes for the year ended December 31, 2012:

Facility	% Owned	Location	Gross Processing Capacity (MMcf/d)	Gross Plant Natural Gas Inlet Throughput Volume (MMcf/d)	Gross NGL Production (MBbl/d)	Process Type	Operated or Non-Operated
Sand Hills							
Sand Hills	100	Crane, TX	180.0	135.0	16.5	Cryogenic	Operated
Pucket/West Seminole (1)				10.1	0.4		
Versado System							
Saunders (2)	63	Lea, NM	70.0			Cryogenic	Operated
Eunice (2)	63	Lea, NM	120.0			Cryogenic	Operated
Monument (2)	63	Lea, NM	90.0			Cryogenic	Operated
		Area Total	280.0	167.4	19.7		
SAOU							
Mertzon	100	Irion, TX	52.0			Cryogenic	Operated
Sterling (3)	100	Sterling, TX	62.0			Cryogenic	Operated
Conger	100	Sterling, TX	25.0			Cryogenic	Operated
		Area Total	139.0	124.8	19.2		
North Texas System							
Chico (4)	100	Wise, TX	265.0			Cryogenic	Operated
Shackelford	100	Shackelford, TX	13.0			Cryogenic	Operated
		Area Total	278.0	244.5	26.8		
Badlands (5)							
Little Missouri (6)	100	McKenzie, ND	20.0	n/a	n/a	Refrigeration	Operated
		Segment System Total	897.0	681.8	66.1		

(1) Pucket/West Seminole includes throughput other than plant inlet, primarily from compressor stations.
(2) These plants are part of our Versado joint venture, of which we own 63%; capacity and volumes represent 100% of ownership interest.
(3) An additional 30 MMcf/d will be commissioned in the first quarter of 2013.
(4) The Chico plant has fractionation capacity of approximately 15 MBbl/d.
(5) Also includes the Johnsons Corner Terminal at 40,000 barrels of crude storage capacity and the Alexander Terminal at 30,000 barrels of crude storage capacity.
(6) Acquired December 31, 2012.

Coastal Gathering and Processing Segment

The Partnership's Coastal Gathering and Processing segment assets are located in the onshore region of the Louisiana Gulf Coast and the Gulf of Mexico. With the strategic location of its assets in Louisiana, the Partnership has access to the Henry Hub, the largest natural gas hub in the U.S., and to a substantial NGL distribution system with access to markets throughout Louisiana and the southeast U.S. The Coastal Gathering and Processing segment's assets consist of the Coastal Straddles and LOU, each as described below. For the year ended 2012, the Partnership processed an average of approximately 1,416.4 MMcf/d of plant natural gas inlet and produced an average of approximately 46.1

MBbl/d of NGLs.

Coastal Straddles

Coastal Straddles consists of three wholly owned and operated gas processing plants and seven partially owned plants, some of which are operated by the Partnership, two of which were shut down in 2012 (Calumet in January and Yscloskey in September). The plants, having an aggregated processing capacity of approximately 4,730 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 three offshore gathering systems that are operated by the Partnership. The Pelican and Seahawk gathering systems have a combined length of approximately 175 miles and a combined capacity of approximately 230 MMcf per day. 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. Additionally, through the Partnership's 77% ownership interest in VESCO, it operates the Venice Gathering System ("VGS"), an offshore gathering system. VGS is approximately 150 miles in length and has a nominal capacity of 320 MMcf per day. VGS gathers natural gas from the shallow waters of the eastern Gulf of Mexico and supplies a portion of the natural gas to the Venice gas plant.

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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 the Partnership. Coastal Straddles has access to markets across the U.S. through the interstate natural gas pipelines to which they are interconnected. The industry continues to rationalize gas processing capacity along the Gulf Coast by moving gas from older, less efficient plants to higher efficiency cryogenic plants such as our VESCO plant.

LOU

LOU consists of approximately 896 miles of gathering system pipelines, covering approximately 3,800 square miles in Southwest Louisiana. The gathering system is connected to numerous producing wells and/or central delivery points 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 460 MMcf/d. In addition, the Gillis plant has integrated fractionation with operating capacity of approximately 13 MBbl/d.

The following table lists the Coastal Gathering and Processing segment's natural gas processing plants and related volumes for the year ended December 31, 2012:

Facility	% Owned	Location	Gross Processing Capacity (MMcf/d)	Gross Plant Natural Gas Inlet Throughput Volume (MMcf/d)	Gross NGL Production (MBbl/d)	Process Type (7)	Operated or Non-operated
Coastal Straddles (1)							
Barracuda	100	Cameron, LA	190	77.0	1.8	Cryo	Operated
Stingray	100	Cameron, LA	300	126.3	3.1	RA	Operated
Lowry	100	Cameron, LA	265	178.1	4.3	Cryo	Operated
Calumet (2)	32.4	St. Mary, LA	-	7.1	0.2	RA	Non-operated
Yscloskey (3)(4)	25.3	St. Bernard, LA	-	125.8	0.8	RA	Operated
Bluewater	21.8	Acadia, LA	425	*	*	Cryo	Non-operated
Terrebonne (4)	4.8	Terrebonne, LA	950	18.6	0.6	RA	Non-operated
Toca (4)	10.7	St. Bernard, LA	1,150	43.1	1.0	Cryo/RA	Non-operated
Sea Robin	0.8	Vermillion, LA	700	15.4	0.4	Cryo	Non-operated
VESCO	76.8	Plaquemines, LA	750	479.5	22.1	Cryo	Operated
Other (5)				84.9	3.2		
		Area Total	4,730	1,155.8	37.5		

LOU							
Gillis (6)	100	Calcasieu, LA	180			Cryo	Operated
Acadia	100	Acadia, LA	80			Cryo	Operated
Big Lake	100	Calcasieu, LA	200			Cryo	Operated
		Area Total	460	260.6	8.6		
	Consolidated System Total		5,190	1,416.4	46.1		

* Not available.

(1) Coastal Straddles also includes three offshore gathering systems which have a combined length of approximately 300 miles.
(2) Plant shut down in January 2012.
(3) Plant shut down in September 2012.
(4) Our ownership is adjustable and subject to annual redetermination based on our proportionate share of owners production.
(5) Other includes Sabine Pass and Neptune volumes processed at plants not owned by us.
(6) The Gillis plant has fractionation capacity of approximately 13 MBbl/d.
(7) Cryo – Cryogenic Processing; RA – Refrigerated Absorption Processing.

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Logistics and Marketing Division

The Partnership's Logistics and Marketing Division is also referred to as the Downstream Business. It includes the activities necessary to convert mixed NGLs into NGL products and provide certain value added services such as the fractionation, storage, terminaling, transportation, distribution and marketing of NGLs and NGL products; and storing and terminaling refined petroleum products and crude oil, as well as certain natural gas supply and marketing activities in support of the Partnership's other businesses. These products are delivered to end-users through pipelines, barges, 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

This 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. The Partnership's logistics assets are generally connected to, and supplied in part by, its gathering and processing assets and are primarily located at Mont Belvieu and Galena Park near Houston, Texas and in Lake Charles, Louisiana, except for the Badlands North Dakota crude oil midstream assets which are included in the Partnership's Field Gathering and Processing segment. 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. Mixed NGLs delivered from the Partnership's Field and Coastal Gathering and Processing segments represent the largest single source of volumes processed by its NGL fractionators.

The Partnership's fractionation assets include ownership interests in three stand-alone fractionation facilities that are located on the Gulf Coast, two of which it operates, one at Mont Belvieu, Texas and the other at Lake Charles, Louisiana. The Partnership has an equity investment in the third fractionator, GCF, also located at Mont Belvieu. The Partnership is subject to a consent decree with the Federal Trade Commission, issued December 12, 1996, that, among other things, prevents it from participating in commercial decisions regarding rates paid by third parties for fractionation services at GCF. This restriction on the Partnership's activity at GCF will terminate on December 12, 2016, 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 the Gathering and Processing division.

The majority of the Partnership's NGL fractionation business is under fee-based arrangements. These fees are subject to adjustment for changes in certain fractionation expenses, including energy costs. The operating results of the Partnership's NGL fractionation business are dependent upon the volume of mixed NGLs fractionated 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, 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 enacted by the Federal Energy Regulatory Commission ("FERC") should result in volumes of mixed NGLs being available for fractionation because natural gas requires processing or conditioning to meet pipeline quality specifications. These requirements establish a base volume of mixed NGLs during periods when it might be otherwise uneconomical to process certain sources of natural gas. Furthermore, significant volumes of mixed NGLs are contractually committed to the Partnership's NGL fractionation facilities.

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

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The Partnership also has a natural gasoline hydrotreater at Mont Belvieu, Texas that removes sulfur from natural gasoline, allowing customers to meet new, more stringent environmental standards. The facility has a capacity of 30 MBbl/d and is supported by fee-based contracts with Marathon Petroleum Company LLC ("Marathon") and Koch Supply and Trading LP that have certain guaranteed volume commitments or provisions for deficiency payments.

Modifications have been made to this process to also provide for benzene treating for Marathon's account. This new process commenced operations in January 2012, which effectively reset Marathon's term for five years beginning February 1, 2012. 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	Maximum Gross Capacity (MBbl/d)	Gross Throughput for 2012 (MBbl/d)
Operated Fractionation Facilities:			
Lake Charles Fractionator (Lake Charles, LA)	100.0	55.0	34.4
Cedar Bayou Fractionator (Mont Belvieu, TX)	88.0	293.0	250.6
Targa LSNG Hydrotreater (Mont Belvieu, TX)	100.0	30.0	22.4
Non-operated Fractionation Facilities:			
Gulf Coast Fractionator (Mont Belvieu, TX)	38.8	145.0	97.0

Storage, Terminaling and Petroleum Logistics

In general, the Partnership's storage assets provide warehousing of mixed NGLs, NGL products and petrochemical products in underground wells, which allows for the injection and withdrawal of such products at various times in order to meet supply and demand cycles. Similarly, the Partnership's terminaling operations provide the inbound/outbound logistics and warehousing of mixed NGLs, NGL products and petrochemical products in above-ground storage tanks. The Partnership's 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 customers. The Partnership provides long and short term storage and terminaling services and throughput capability to third-party customers for a fee.

The Partnership's Petroleum Logistics business consists of storage and terminaling facilities in Texas (the Channelview and the Patriot Terminal), 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, the Partnership owns or operates a total of 39 storage wells at its facilities with a net storage capacity of approximately 64 MMBbl, the usage of which may be limited by brine handling capacity, which is utilized to displace NGLs from storage.

The Partnership operates its storage and terminaling facilities based on the needs and requirements of its customers. The Partnership usually experiences an increase in demand for storage and terminaling of mixed NGLs during the summer months when gas plants typically reach peak NGL production, refineries have excess NGL products and LPG imports are often highest. Demand for storage and terminaling at the Partnership's propane facilities typically peaks during fall, winter and early spring. The Partnership has experienced significant demand growth for NGL (primarily propane) exports, and expects that trend to continue with its announced international grade propane exports project.

The Partnership's fractionation, storage and terminaling business is supported by approximately 940 miles of company-owned pipelines to transport mixed NGLs and specification products.

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The following table details the Logistics Assets NGL storage facilities at December 31, 2012:

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) The Partnership owns 20 wells and operates 6 wells owned by Chevron Phillips Chemical Company LLC.

The following table details the Logistics Assets Terminal Facilities for the year ended December 31, 2012:

Facility	% Owned	County/Parish, State	Description	Throughput for 2012 (Million gallons)	Usable Storage Capacity (MMBbl)
Galena Park Terminal (1)	100	Harris, TX	NGL import/export terminal	288.5	0.7
Mont Belvieu Terminal	100	Chambers, TX	Transport and storage terminal	2,458.4	39.0
Hackberry Terminal	100	Cameron, LA	Storage terminal	1,088.0	17.8
Channelview Terminal	100	Harris, TX	Transport and storage terminal	0.1	0.5
Baltimore Terminal	100	Baltimore, MD	Transport and storage terminal	-	0.5
Sound Terminal	100	Pierce, WA	Transport and storage terminal	215.0	0.8
Patriot Terminal	100	Harris, TX	Dock and land for expansion	(2)	-

(1) Volumes reflect total import and export across the dock/terminal.
(2) Not in service.

Marketing and Distribution Segment

The Marketing and Distribution segment transports, distributes and markets NGLs via terminals and transportation assets across the U.S. The Partnership owns or commercially manages terminal facilities in a number of states, including Texas, Louisiana, Arizona, Nevada, California, Florida, Alabama, Mississippi, Tennessee, Kentucky, New Jersey and Washington. The geographic diversity of the Partnership's assets provide direct access to many NGL customers as well as markets via trucks, barges, rail cars and open-access regulated NGL pipelines owned by third parties. The Marketing and Distribution segment consists of (i) NGL Distribution and Marketing, (ii) Wholesale Marketing, (iii) Refinery Services, (iv) Commercial Transportation, (v) Natural Gas Marketing and (vi) Terminal Facilities, each as described below.

NGL Distribution and Marketing

The Partnership markets its own NGL production and also purchases component NGL products from other NGL producers and marketers for resale. During the year ended December 31, 2012, the Partnership's distribution and marketing services business sold an average of approximately 289.8 MBbl/d of NGLs.

The Partnership generally purchases mixed NGLs from producers at a monthly pricing index less applicable fractionation, transportation and marketing fees and resells these products to petrochemical manufacturers, refineries and other marketing and retail companies. This is primarily a physical settlement business in which the Partnership earns margins from purchasing and selling NGL products from producers under contract. The Partnership also earns margins by purchasing and reselling NGL products in the spot and forward physical markets. To effectively serve the Partnership's Distribution and Marketing customers, it contracts for and uses many of the assets included in its Logistics Assets segment. The Partnership also markets natural gas available to it from its Gathering and Processing segments, and purchases and resells natural gas in selected United States markets.

Wholesale Marketing

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

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 the Partnership serves and impact the ability to deliver propane to satisfy peak demand.

Refinery Services

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

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

Commercial Transportation

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

The Partnership's transportation assets, as of December 31, 2012, include:

- approximately 555 railcars that the Partnership leases and manages;
- approximately 82 owned and leased transport tractors and approximately 104 company owned tank trailers; and
- 20 company-owned pressurized NGL barges.

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Natural Gas Marketing

The Partnership also markets natural gas available to it from the Gathering and Processing segments, and purchases and resells natural gas in selected United States markets.

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

Facility	% Owned	County/Parish, State	Description	Throughput for 2012 (Million gallons) (1)	Usable Storage Capacity (Million gallons)
Calvert City Terminal	100	Marshall, KY	Propane terminal	7.9	0.1
Greenville Terminal	100	Washington, MS	Marine propane terminal	13.4	1.5
Port Everglades Terminal	100	Broward, FL	Marine propane terminal	5.1	1.6
Tyler Terminal	100	Smith, TX	Propane terminal	26.3	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	1.7	0.1
Gladewater Transport (2)	100	Gregg, TX	Raw NGL transport terminal	8.1	0.3
Chattanooga Terminal	100	Hamilton, TN	Propane terminal	7.9	0.9
Sparta Terminal	100	Sparta, NJ	Propane terminal	10.7	0.2
Hattiesburg Terminal (3)	50	Forrest, MS	Propane terminal	243.1	269.6
Winona Terminal	100	Flagstaff, AZ	Propane terminal	10.1	0.3
Sound Terminal (4)	100	Pierce, WA	Propane terminal	3.0	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 is based on total facility capacity.
(4) Operated by Logistics Assets segment.

Operational Risks and Insurance

The Partnership is subject to all risks inherent in the midstream natural gas, crude oil and petroleum logistics businesses. These risks include, but are not limited to, explosions, fires, mechanical failure, terrorist attacks, product spillage, weather, nature and inadequate maintenance of rights-of-way and could result in damage to or destruction of operating assets and other property, or could result in personal injury, loss of life or polluting the environment, as well as curtailment or suspension of operations at the affected facility. We maintain, on behalf of ourselves and our subsidiaries, including the Partnership, general public liability, property, boiler and machinery and business interruption insurance in amounts that we consider to be appropriate for such risks. Such insurance is subject to deductibles that we consider reasonable and not excessive given the current insurance market environment. The 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 the Partnership's operations and the Partnership's and our financial condition. While we currently maintain levels and types of insurance that we believe to be prudent under current insurance industry market conditions, our inability to secure these levels and types of insurance in the future could negatively impact the Partnership business operations and the Partnership's and our financial stability, particularly if an uninsured loss were to occur. No assurance can be given that we will be able to maintain these levels of insurance in the future at rates considered commercially reasonable, particularly named windstorm coverage and contingent business interruption coverage for our onshore operations.

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Significant Customer

The following table lists the percentage of the Partnership's consolidated sales with its significant customer:

	2012	2011	2010
% of consolidated revenues			
Chevron Phillips Chemical Company LLC	10%	12%	10%

The Partnership has agreements with Chevron Phillips Chemical Company LLC ("CPC"), pursuant to which it supplies 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 the Partnership provides 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 10 year term. In September 2009, the Partnership executed a new feedstock and storage agreement with CPC for a term of 5 years, which will renew annually following the end of the five year term unless terminated by either party. We believe that the Partnership is well positioned to retain CPC as a customer based on the Partnership's 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 the Partnership's assets. In addition to these two agreements, The Partnership has fractionation agreements in place with CPC for Y-grade streams and butanes.

No other customer accounted for more than 10% of the Partnership's consolidated revenues during these periods.

Competition

The Partnership faces strong competition in acquiring new natural gas supplies. Competition for natural gas supplies is primarily based on the location of gathering and processing facilities, pricing arrangements, reputation, efficiency, flexibility, reliability and access to end-use markets or liquid marketing hubs. Competitors to the Partnership's gathering and processing operations include other natural gas gatherers and processors, such as major interstate and intrastate pipeline companies, master limited partnerships and oil and gas producers. The Partnership's major competitors for natural gas supplies in our current operating regions include Atlas Gas Pipeline Company, Copano Energy, L.L.C. ("Copano"), 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. The Partnership's competitors for crude oil gathering services in North Dakota include Arrow Midstream Holdings, LLC, Hiland Partners, LP, Great Northern Midstream LLC, Caliber Midstream Partners, LP and Bridger Pipeline LLC. The Partnership's competitors may have greater financial resources than it possesses.

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

Additionally, the Partnership faces competition for mixed NGLs supplies at its fractionation facilities. Its competitors include large oil, natural gas and petrochemical companies. The fractionators in which the Partnership owns an interest in the Mont Belvieu region compete for volumes of mixed NGLs with other fractionators also located at Mont Belvieu. Among the primary competitors are Enterprise Products Partners L.P., ONEOK, Inc. and LoneStar NGL LLC. In addition, certain producers fractionate mixed NGLs for their own account in captive facilities. The Mont Belvieu fractionators also compete on a more limited basis with fractionators in Conway, Kansas and a number of decentralized, smaller fractionation facilities in Texas, Louisiana and New Mexico. The Partnership's other fractionation facilities compete for mixed NGLs with the fractionators at Mont Belvieu as well as other fractionation facilities located in Louisiana. The Partnership's customers who are significant producers of mixed NGLs and NGL products or consumers of NGL products may develop their own fractionation facilities in lieu of using the Partnerships' services.

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Regulation of Operations

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

Regulation of Interstate Natural Gas Pipelines

VGS is regulated by FERC under the Natural Gas Act of 1938 ("NGA"), and the Natural Gas Policy Act of 1978 ("NGPA"). VGS operates under a FERC approved, open-access tariff that establishes rates and 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

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

Section 1(b) of the NGA exempts natural gas gathering facilities from regulation as a natural gas company by FERC under the NGA. We believe that the natural gas pipelines in the Partnership's gathering systems meet, including the gas gathering system that is a part of the Badlands assets and the Pelican and Seahawk gathering systems, 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, on-going litigation, so the classification and regulation of the Partnership's gathering facilities are subject to change based on future determinations by FERC, the courts or Congress. Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels. The Partnership's natural gas gathering operations could be adversely affected should they be subject to more stringent application of state or federal regulation of rates and services. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. We cannot predict what effect, if any, such changes might have on the Partnership's operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

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In 2007, Texas enacted new laws regarding rates, competition and confidentiality for natural gas gathering and transmission pipelines ("Competition Statute") and new informal complaint procedures for challenging determinations of lost and unaccounted for gas by gas gatherers, processors and transporters ("LUG Statute"). The Competition Statute gives the Railroad Commission of Texas ("RRC") the ability to use either a cost-of-service method or a market-based method for setting rates for natural gas gathering and transportation pipelines in formal rate proceedings. This statute also gives the RRC specific authority to enforce its statutory duty to prevent discrimination in natural gas gathering and transportation, to enforce the requirement that parties participate in an informal complaint process and to punish purchasers, transporters, and gatherers for taking discriminatory actions against shippers and sellers. The Competition Bill also provides producers with the unilateral option to determine whether or not confidentiality provisions are included in a contract to which a producer is a party for the sale, transportation, or gathering of natural gas. The LUG Statute modifies the informal complaint process at the RRC with procedures unique to lost and unaccounted for gas issues. Such statute also extends the types of information that can be requested and provides the RRC with the authority to make determinations and issue orders in specific situations. We cannot predict what effect, if any, these statutes might have on the Partnership's future operations in Texas.

Intrastate Pipeline Regulation

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

The Partnership's intrastate pipelines located in Texas are regulated by the RRC. The Partnership's Texas intrastate pipeline, Targa Intrastate Pipeline LLC ("Targa Intrastate"), owns the intrastate pipeline that transports natural gas from the Partnership's Shackelford processing plant to an interconnect with Atmos Pipeline-Texas that in turn delivers gas to the West Texas Utilities Company's Paint Creek Power Station. Targa Intrastate also owns a 1.65 mile, 10 inch diameter intrastate pipeline that transports natural gas from a third-party gathering system into the Chico System in Denton County, Texas. Targa Intrastate is a gas utility subject to regulation by the RRC and has a tariff on file with such agency.

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

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

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

The Partnership's intrastate pipelines in North Dakota are subject to the various regulations of the State of North Dakota.

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Natural Gas Processing

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

Availability, Terms and Cost of Pipeline Transportation

The Partnership's processing facilities and marketing of natural gas and NGLs are affected by the availability, terms and cost of pipeline transportation. The price and terms of access to pipeline transportation can be subject to extensive federal and, if a complaint is filed, state regulation. FERC is continually proposing and implementing new rules and regulations affecting the interstate transportation of natural gas, and to a lesser extent, the interstate transportation of NGLs. These initiatives also may indirectly affect the intrastate transportation of natural gas and NGLs under certain circumstances. We cannot predict the ultimate impact of these regulatory changes to the Partnership's processing operations and its natural gas and NGL marketing operations. We do not believe that the Partnership would be affected by any such FERC action materially differently than other natural gas processors and natural gas and NGL marketers with whom it competes. The ability of the Partnership's processing facilities and pipelines to deliver natural gas into third-party natural gas pipeline facilities is directly impacted by the gas quality specifications required by those pipelines. In 2006, FERC issued a policy statement on provisions governing gas quality and interchangeability in the tariffs of interstate gas pipeline companies and a separate order declining to set generic prescriptive national standards. FERC strongly encouraged all natural gas pipelines subject to its jurisdiction to adopt, as needed, gas quality and interchangeability standards in their FERC gas tariffs modeled on the interim guidelines issued by a group of industry representatives, headed by the Natural Gas Council ("NGC+ Work Group"), or to explain how and why their tariff provisions differ. We do not believe that the adoption of the NGC+ Work Group's gas quality interim guidelines by a pipeline that either directly or indirectly interconnects with the Partnership's facilities would materially affect its operations. We have no way to predict, however, whether FERC will approve of gas quality specifications that materially differ from the NGC+ Work Group's interim guidelines for such an interconnecting pipeline.

Sales of Natural Gas and NGLs

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

Other State and Local Regulation of Operations

The Partnership's business activities are subject to various state and local laws and regulations, as well as orders of regulatory bodies pursuant thereto, governing a wide variety of matters, including marketing, production, pricing, community right-to-know, protection of the environment, safety and other matters. For additional information regarding the potential impact of federal, state or local regulatory measures on our business, see “Risk Factors—Risks Related to Our Business.”

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Interstate common carrier liquids pipeline regulation

The Partnership acquired Targa NGL Pipeline Company LLC ("Targa NGL") which 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 the Partnership maintain tariffs on file with FERC for each of these pipelines. Those tariffs set forth the rates the Partnership charges for providing transportation services as well as the rules and regulations governing these services. The ICA requires, among other things, that rates on interstate common carrier pipelines be "just and reasonable" and non-discriminatory. All shippers on this pipeline are our subsidiaries.

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

Other Federal Laws and Regulations Affecting Our Industry

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, 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 EP Act of 2005. Order No. 670 makes it unlawful: (1) in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit any statement necessary to make the statements made not misleading; or (3) to engage in any act or practice that operates as a fraud or deceit upon any person. 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.

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FERC Standards of Conduct for Transmission Providers

On October 16, 2008, FERC issued new standards of conduct for transmission providers (Order No. 717) to regulate the manner in which interstate natural gas pipelines may interact with their marketing affiliates based on an employee separation approach. A “Transmission Provider” includes an interstate natural gas pipeline that provides open access transportation pursuant to FERC’s regulations. Under these rules, a Transmission Provider’s transmission function employees (including the transmission function employees of any of its affiliates) must function independently from the Transmission Provider’s marketing function employees (including the marketing function employees of any of its affiliates). FERC clarified on October 15, 2009 in a rehearing order, Order No. 717-A, however, that if a Hinshaw pipeline affiliated with a Transmission Provider engages in off-system sales of gas that has been transported on the Transmission Provider’s affiliated pipeline, then the Transmission Provider and the Hinshaw pipeline (which is engaging in marketing functions) will be required to observe the Standards of Conduct by, among other things, having the marketing function employees function independently from the transmission function employees. The Partnership’s only Hinshaw pipeline, TLI, does not engage in any off-system sales of gas that have been transported on an affiliated Transmission Provider, and we do not believe that the Partnership’s operations will be affected by the new standards of conduct. FERC further clarified Order No. 717-A in a rehearing order, Order No. 717-B, on November 16, 2009, in Order No. 717-C, on April 16, 2010, and in Order No. 717-D, on April 8, 2011. However, Order Nos. 717-B, 717-C, and 717-D did not substantively alter the rules promulgated under Orders Nos. 717 and 717-A. The Partnership’s only Transmission Provider, VGS, does not engage in any transactions with marketing affiliates, and we do not believe that the Partnership’s operations will be affected by the new standards of conduct.

FERC Market Transparency Rules

In 2007, FERC issued Order No. 704, whereby 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, beginning in 2009, 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. It is the responsibility of the reporting entity to determine which transactions should be reported based on the guidance of Order No. 704 as clarified in orders on clarification and rehearing. On November 15, 2012, FERC issued a Notice of Inquiry seeking comments on whether requiring all market participants engaged in sales of wholesale physical natural gas in interstate commerce to report quarterly to the Commission every natural gas transaction within the Commission’s NGA jurisdiction that entails physical delivery for the next day or for the next month will improve natural gas market transparency.

On November 20, 2008, FERC issued a final rule on daily scheduled flows and capacity posting requirements (Order No. 720). Under Order No. 720, as clarified in orders on clarification and rehearing certain non-interstate pipelines delivering, on an annual basis, more than an average of 50 million MMBtu of gas over the previous three calendar years, are required to post daily 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 with respect to its application to non-interstate pipelines. In December 2011, the Fifth Circuit confirmed that Order No. 720, as clarified, remained applicable to interstate pipelines with respect to posting information regarding the provision of no-notice service. The Partnership takes the position that, at this time, all of its entities are exempt from this rule as currently written.

On May 20, 2010, the FERC issued Order No. 735, which requires intrastate pipelines providing transportation services under Section 311 of the NGPA and “Hinshaw” pipelines operating under Section 1(c) of the NGA 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 further requires that such information must be supplied through a new electronic reporting system and will be posted on FERC’s website, and that such quarterly reports may not contain information redacted as privileged. The FERC promulgated this Rule after determining that such transactional information would help shippers make more informed purchasing decisions and would improve the ability of both shippers and the FERC to monitor actual transactions for evidence of market power or undue discrimination. Order No. 735 also extends the Commission’s periodic review of the rates charged by the subject pipelines from three years to five years. Order No. 735 became effective on April 1, 2011. On December 16, 2010, the Commission issued Order No. 735-A. In Order No. 735-A, the Commission generally reaffirmed Order No. 735 requiring section 311 and Hinshaw pipelines to report on a quarterly basis storage and transportation transactions containing specific information for each transaction, aggregated by contract. Order No. 735-A did grant rehearing of three requests, including removing the requirement that the quarterly reports include the contract end-date for interruptible transactions, eliminating the increased per-customer revenue reporting requirements, and extending the deadline for submitting the quarterly reports from 30 days to 60 days following the quarter end date. As currently written, this rule does not apply to the Partnership’s Hinshaw pipelines.

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

Environmental and Operational Health and Safety Matters

General

The Partnership's operations are subject to stringent and complex federal, state and local laws and regulations governing the discharge of materials into the environment, worker health and safety, or otherwise relating to environmental protection. As with the industry generally, compliance with current and anticipated environmental laws and regulations increases the Partnership's overall cost of business, including its capital costs to construct, maintain and upgrade equipment and facilities. These laws and regulations may, among other things, require the acquisition of various permits to conduct regulated activities, require the installation of pollution control equipment or otherwise restrict the way the Partnership can handle or dispose of its 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 the Partnership's operations or attributable to former operations; and enjoin some or all of the operations of facilities deemed in non-compliance with permits issued pursuant to such environmental laws and regulations. Failure to comply with these laws and regulations may result in assessment of administrative, civil and criminal penalties, the imposition of removal or remedial obligations and the issuance of injunctions limiting or prohibiting the Partnership's activities.

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

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

Hazardous Substances and Waste

The Comprehensive Environmental Response, Compensation, and Liability Act, as amended ("CERCLA"), and comparable state laws impose liability without regard to fault or the legality of the original conduct, on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include current and prior owners or operators of the site where the release occurred and entities that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these "responsible persons" may be subject to joint and several, strict liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the Environmental Protection Agency ("EPA") and, in some instances, third-parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other pollutants into the environment. The Partnership generates materials in the course of its operations that are regulated as "hazardous substances" under CERCLA or similar state statutes and, as a result, may be jointly and severally liable under CERCLA or such statutes for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment.

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The Partnership also generates solid wastes, including hazardous wastes that are subject to the requirements of the Resource Conservation and Recovery Act, as amended ("RCRA"), and comparable state statutes. While RCRA regulates both solid and hazardous wastes, it imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. In the course of the Partnership's operations, it generates petroleum product wastes and ordinary industrial wastes such as paint wastes, waste solvents and waste compressor oils that are regulated as hazardous wastes. Certain materials generated in the exploration, development or production of crude oil and natural gas are excluded from RCRA's hazardous waste regulations. However, it is possible that future changes in law or regulation could result in these wastes, including wastes currently generated during the Partnership's operations, being designated as "hazardous wastes" and therefore subject to more rigorous and costly disposal requirements. Any such changes in the laws and regulations could have a material adverse effect on the Partnership's capital expenditures and operating expenses as well as those of the oil and gas industry in general.

The Partnership currently owns or leases and has in the past owned or leased properties that for many years have been used for midstream natural gas and NGL activities and refined petroleum product and crude oil storage and terminaling activities. Although the Partnership has utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other substances and wastes may have been disposed of or released on or under the properties owned or leased by the Partnership or on or under the other locations where these hydrocarbons or other substances and wastes have been taken for treatment or disposal. In addition, certain of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other substances and wastes was not under 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, the Partnership could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) and to perform remedial operations to prevent future contamination. We are not currently aware of any facts, events or conditions relating to such requirements that would reasonably be expected to have a material adverse effect on the Partnership's results of operations or financial condition.

Air Emissions

The federal Clean Air Act, as amended, and comparable state laws and regulations restrict the emission of air pollutants from many sources, including processing plants and compressor stations and also impose various monitoring and reporting requirements. These laws and regulations may require the Partnership to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions. The need to obtain permits has the potential to delay the development of oil and natural gas related projects. Over the next several years, 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. In 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, effective October 15, 2012; (ii) specified pneumatic controllers at gathering systems, boosting facilities, and onshore natural gas processing plants, effective October 15, 2013; and (iii) specified storage vessels at gathering systems, boosting facilities, and onshore natural gas processing plants, effective October 15, 2013. Compliance with these requirements could increase the Partnership's operational costs for upstream and midstream activities, which could be significant.

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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 restrict emissions of GHGs from motor vehicles and another that requires certain construction and operating permit reviews for emissions of GHGs from certain large stationary sources of emissions. In addition, the EPA adopted rules requiring the monitoring and reporting of GHG emissions from certain sources, including, among others, onshore and offshore oil and natural gas production facilities and onshore oil and natural gas processing, transmission, storage and distribution facilities in the United States on an annual basis. The EPA also assumed responsibility for issuing certain Clean Air Act permits for construction and Title V operating permits for GHG emissions in Texas in December 2010. As a result, those two permitting programs are now subject to dual sets of approvals at the state and federal levels. Operators in Texas with stationary sources emitting GHGs in excess of applicable regulatory thresholds must now obtain separate Clean Air Act permits and/or Title V permits from each of the EPA, with respect to GHG emissions, and the Texas Commission on Environmental Quality ("TCEQ") with respect to all other regulated non-GHG emissions. We are monitoring GHG emissions from the Partnership's operations in accordance with the GHG emissions reporting rule and believe that the Partnership's monitoring and reporting activities are in substantial compliance with applicable reporting obligations.

Also, Congress has from time to time considered legislation to reduce emissions of GHGs, and almost one-half of the states already have taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. The adoption of any legislation or regulations that requires reporting of GHGs or otherwise restricts emissions of GHGs from the Partnership's equipment and operations could require it to incur significant added costs to reduce emissions of GHGs or could adversely affect demand for the natural gas and natural gas liquids the Partnership gathers and processes or fractionates. Finally, some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate change that could have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events; if such effects were to occur, they could have an adverse effect on the Partnership's 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. These permits may require the Partnership to monitor and sample the storm water runoff. The CWA and analogous state laws can impose substantial civil and criminal penalties for non-compliance including spills and other nonauthorized 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. 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 OPA includes owners and operators of onshore facilities, such as the Partnership's plants and pipelines. Under OPA, owners and operators of facilities that handle, store, or transport oil are required to develop and implement oil spill response plans, and establish and maintain evidence of financial responsibility sufficient to cover liabilities related to an oil spill for which such parties could be statutorily responsible. We believe that the Partnership is in substantial compliance with the CWA, OPA and analogous state laws.

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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 federal regulatory authority under the Safe Drinking Water Act ("SDWA") over certain hydraulic fracturing involving the use of diesel fuel and in May 2012 released draft permitting guidance for hydraulic fracturing activities using diesel fuels. In November 2011, the EPA announced its intent to develop and issue regulations under the federal Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing. In addition, legislation has been introduced from time to time before Congress to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. 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 the event that new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where the Partnership's oil and natural gas exploration and production customers' operate, those customers could incur potentially significant added costs to comply with such requirements and experience delays or curtailment in the pursuit of exploration, development, or production activities, which could reduce demand for the Partnership's gathering, processing and fractionation services. In addition, several governmental reviews recently conducted or underway that focus on environmental aspects of hydraulic fracturing activities. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices and the EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a first progress report outlining work currently underway by the agency released on December 21, 2012 and a final report drawing conclusions about hydraulic fracturing on drinking water resources expected to be available for public comment and peer review by 2014. Moreover, the EPA is developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities and plans to propose these standards for shale gas by 2014. In addition, the U.S. Department of Energy has conducted an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic fracturing completion methods and, in August 2011, issued a report on immediate and longer-term actions that may be taken to reduce environmental and safety risks of shale gas development. Also, the U.S. Department of the Interior released draft regulations in May 2012 governing hydraulic fracturing on federal and Indian oil and gas leases to require disclosure of information regarding the chemicals used in hydraulic fracturing, advance approval for well-stimulation activities, mechanical integrity testing of casing, and monitoring of well-stimulation operations. These studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms, which events could delay or curtail production of natural gas by exploration and production operators, some of which may be the Partnership's customers, and thus reduce demand for the Partnership's midstream services.

Endangered Species Act

The federal Endangered Species Act, as amended ("ESA"), restricts activities that may affect endangered or threatened species or their habitats. While some of the Partnership's facilities may be located in areas that are designated as habitat for endangered or threatened species, we believe that the Partnership is in substantial compliance with the ESA. If endangered species are located in areas of the underlying properties where the Partnerships wishes to conduct development activities, such work could be prohibited or delayed or expensive mitigation may be required. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service is required to make a determination on listing of more than 250 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 the Partnership or its oil and natural gas exploration and production customers operate could cause the Partnership or its customers to incur increased costs arising from species protection measures and could result in delays or limitations in the Partnership’s customers performance of operations, which could reduce demand for our Partnership’s midstream services.

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Pipeline Safety

The pipelines used by the Partnership to transport natural gas and transport NGLs are subject to regulation by the DOT under the Natural Gas Pipeline Safety Act of 1968, as amended ("NGPSA"), with respect to natural gas and the Hazardous Liquids Pipeline Safety Act of 1979, as amended ("HLPSA"), with respect to crude oil, NGLs and condensates. The NGPSA and HLPSA govern the design, installation, testing, construction, operation, replacement and management of natural gas and NGL pipeline facilities. Pursuant to these acts, the DOT 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. Where applicable, the NGPSA and HLPSA require any entity that owns or operates pipeline facilities to comply with the regulations under these acts, to permit access to and allow copying of records and to make certain reports and provide information as required by the Secretary of Transportation. We believe that the Partnership's pipeline operations are in substantial compliance with applicable NGPSA and HLPSA requirements; however, due to the possibility of new or amended laws and regulations or reinterpretation of existing laws and regulations, future compliance with the NGPSA and HLPSA could result in increased costs.

The Partnership's pipelines are also subject to regulation by the DOT under the Pipeline Safety Improvement Act of 2002, which was amended by the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 ("PIPES Act"). The DOT, through the Pipeline and Hazardous Materials Safety Administration ("PHMSA") has established a series of rules, which require pipeline operators to develop and implement integrity management programs for gas transmission pipelines that, in the event of a failure, could affect "high consequence areas." "High consequence areas" are currently defined as areas with specified population densities, buildings containing populations of limited mobility and areas where people gather that are located along the route of a pipeline. Similar rules are also in place for operators of hazardous liquid pipelines including lines transporting NGLs and condensates.

In addition, states have adopted regulations, similar to existing DOT 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. The Partnership currently estimates an annual average cost of $2.1 million for years 2013 through 2015 to perform necessary integrity management program testing on its pipelines required by existing DOT 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 the Partnership's financial condition or results of operations.

Moreover, changes to pipeline safety laws and regulations that result in more stringent or costly safety standards could have a significant adverse effect on the Partnership and similarly situated midstream operators. On January 3, 2012, 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, and leak detection system installation. The 2011 Pipeline Safety Act also directs owners and operators of interstate and intrastate gas transmission pipelines to verify their records confirming the maximum allowable pressure of pipelines in certain class locations and high consequence areas, requires promulgation of regulations for conducting tests to confirm the material strength of pipe operating above 30% of specified minimum yield strength in high consequence areas, and increases the maximum penalty for violation of pipeline safety regulations from $1 million to $2 million. Also, in August 2011, PHMSA published an advance notice of proposed rulemaking in which the agency is seeking public comment on a number of changes to regulations governing the safety of gas transmission pipelines and gathering lines, including, for example, (i) revising the definitions of "high consequence areas" and "gathering lines"; (ii) strengthening integrity management requirements as they apply to existing regulated operators and to currently exempt operators should certain exemptions be removed; (iii) strengthening requirements on the types of gas transmission pipeline integrity assessment methods that may be selected for use by operators; (iv) imposing gas transmission integrity management requirements on onshore gas gathering lines; (v) requiring the submission of annual, incident and safety-related conditions reports by operators of all gathering lines; and (vi) enhancing the current requirements for internal corrosion control of gathering lines. The safety enhancement requirements and other provisions of the 2011 Pipeline Safety Act as well as any adoption of the proposed PHMSA regulations applying more comprehensive or stringent pipeline safety standards could require the Partnership to install new or modified safety controls, pursue additional capital projects, or conduct maintenance programs on an accelerated basis, any or all of which tasks could result in the Partnership incurring increased operating costs that could be significant and have a material adverse effect on its results of operations or financial position.

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Employee Health and Safety

We and the Partnership 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 the Partnership's operations and that this information be provided to employees, state and local government authorities and citizens. The Partnership and the entities in which it owns an interest are also subject to OSHA Process Safety Management regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. These regulations apply to any process which involves a chemical at or above the specified thresholds or any process which involves flammable liquid or gas, pressurized tanks, caverns and wells in excess of 10,000 pounds at various locations. Flammable liquids stored in atmospheric tanks below their normal boiling point without the benefit of chilling or refrigeration are exempt. The Partnership has an internal program of inspection designed to monitor and enforce compliance with worker safety requirements. We believe that we and the Partnership are in substantial compliance with all applicable laws and regulations relating to worker health and safety.

Title to Properties and Rights-of-Way

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

We may continue to hold record title to portions of certain assets until we make the appropriate filings in the jurisdictions in which such assets are located and obtain any consents and approvals that are not obtained prior to transfer. Such consents and approvals would include those required by federal and state agencies or political subdivisions. In some cases, we may, where required consents or approvals have not been obtained, temporarily hold record title to property as nominee for our benefit and in other cases may, on the basis of expense and difficulty associated with the conveyance of title, cause us to retain title, as nominee for our benefit, until a future date. We anticipate that there will be no material change in the tax treatment of our common units resulting from the holding by us of title to any part of such assets subject to future conveyance or as our nominee.

Employees

Through a wholly-owned subsidiary of ours, we employ 1,192 people who primarily support the Partnership's operations. None of these employees are covered by collective bargaining agreements. We consider our employee relations to be good.

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Financial Information by Reportable Segment

See “Segment Information” included under Note 23 to our “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 of the Partnership – 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.

The nature of our business activities subjects us to certain hazards and risks. You should consider carefully the following risk factors together with all of the other information contained in this report. If any of the following risks were actually to occur, then our business, financial condition, cash flows and results of operations could be materially adversely affected.

Risks Related to Our Business

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

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

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

- Our obligation to satisfy tax obligations associated with previous sales of assets to the Partnership;
- interest expense and principal payments on any indebtedness we incur;

restrictions on distributions contained in any existing or future debt agreements;

our general and administrative expenses, including expenses we incur as a result of being a public company as well as other operating expenses;

expenses of the general partner;

income taxes;

reserves we establish in order for us to maintain our 2% general partner interest in the Partnership upon the issuance of additional partnership securities by the Partnership; and reserves our board of directors establishes for the proper conduct of our business, to comply with applicable law or any agreement binding on us or our subsidiaries or to provide for future dividends by us.

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

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

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

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

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

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

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

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

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

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

We own the general partner, which owns the IDRs in the Partnership that entitle us to receive increasing percentages, up to a maximum of 48% of any cash distributed by the Partnership as certain target distribution levels are reached in excess of $0.3881 per common unit in any quarter. A substantial portion of the cash flow we receive from the Partnership is provided by these IDRs. Because of the high percentage of the Partnership's incremental cash flow that is distributed to the IDRs, certain potential acquisitions might not increase cash available for distribution per Partnership unit. In order to facilitate acquisitions by the Partnership or for other reasons, the board of directors of the general partner may elect to reduce the IDRs payable to us with our consent. These reductions may be permanent reductions in the IDRs or may be reductions with respect to cash flows from the potential acquisition. If distributions on the IDRs were reduced for the benefit of the Partnership units, the total amount of cash distributions we would receive from the Partnership, and therefore the amount of cash dividends we could pay to our stockholders, would be reduced.

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

Because our only source of operating cash flow consists of cash distributions from the Partnership, the amount of dividends we are able to pay to our stockholders may fluctuate based on the level of distributions the Partnership makes to its partners, including us. The Partnership may not continue to make quarterly distributions at the 2012 fourth quarter distribution level of $0.68 per common unit, or may not distribute any other amount, or increase its quarterly distributions in the future. In addition, while we would expect to increase or decrease dividends to our stockholders if the Partnership increases or decreases distributions to us, the timing and amount of such changes in distributions, if any, will not necessarily be comparable to the timing and amount of any changes in dividends made by us. Factors such as reserves established by our board of directors for our estimated general and administrative expenses as well as other operating expenses, reserves to satisfy our debt service requirements, if any, and reserves for future dividends by us may affect the dividends we make to our stockholders. The actual amount of cash that is available for dividends to our stockholders will depend on numerous factors, many of which are beyond our control.

Our cash dividend policy limits our ability to grow.

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

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

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

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

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

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

- adversely affect our ability to obtain additional financing for future operations or capital needs;
- limit our ability to pursue acquisitions and other business opportunities;
- make our results of operations more susceptible to adverse economic or operating conditions; or
- limit our ability to pay dividends.

Our payment of any principal and interest will reduce our cash available for dividends to our stockholders. In addition, we are able to incur substantial additional indebtedness in the future. If we incur additional debt, the risks associated with our leverage would increase. For more information regarding our credit facility, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources."

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

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

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

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

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

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

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

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

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Our historical financial information may not be representative of our future performance.

The historical financial information included in this annual report is derived from our historical financial statements including for periods prior to our initial public offering in December 2010. Our audited historical financial statements were prepared in accordance with GAAP. Accordingly, the historical financial information included in this annual report does not reflect what our results of operations and financial condition would have been had we been a public entity during the periods presented, or what our results of operations and financial condition will be in the future.

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

Our success is dependent upon the efforts of the named executive officers. Our named executive officers are responsible for executing our and the Partnership's business strategies and, when appropriate to our primary business objective, facilitating the Partnership's growth through various forms of financial support provided by us, including, but not limited to, modifying the Partnership's IDRs, exercising the Partnership's IDR reset provision contained in its partnership agreement, making loans, making capital contributions in exchange for yielding or non-yielding equity interests or providing other financial support to the Partnership. There is substantial competition for qualified personnel in the midstream natural gas industry. We may not be able to retain our existing named executive officers or fill new positions or vacancies created by expansion or turnover. We have not entered into employment agreements with any of our named executive officers. In addition, we do not maintain "key man" life insurance on the lives of any of our named executive officers. A loss of one or more of our named executive officers could harm our and the Partnership's business and prevent us from implementing our and the Partnership's business strategies.

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

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

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

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

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

We or our stockholders may sell shares of common stock in subsequent public offerings. We may also issue additional shares of common stock or convertible securities. As of December 31, 2012, we have 42,294,502 outstanding shares of common stock. Certain of our existing stockholders, including our executive officers, certain of our directors and affiliates of Warburg Pincus LLC ("Warburg Pincus") are party to a registration rights agreement with us which requires us to affect the registration of their shares in certain circumstances no earlier than the expiration of the lock-up period contained in the underwriting agreement of our initial public offering.

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

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

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

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

limitations on the removal of directors; and

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

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

We have a significant stockholder, which will limit other stockholders' ability to influence corporate matters and may give rise to conflicts of interest.

As of December 31, 2012, affiliates of Warburg Pincus beneficially owned approximately 11.1% of our outstanding common stock. See "Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters." Accordingly, Warburg Pincus can exert significant influence over us and any action requiring the approval of the holders of our stock, including the election of directors and approval of significant corporate transactions. Warburg's concentrated ownership makes it less likely that any other holder or group of holders of common stock will be able to affect the way we are managed or the direction of our business. These factors also may delay or prevent a change in our management or voting control.

Furthermore, conflicts of interest could arise in the future between us, on the one hand, and Warburg Pincus and its affiliates, on the other hand, concerning, among other things, potential competitive business activities, business opportunities, the issuance of additional securities, the payment of dividends by us and other matters. Warburg Pincus is a private equity firm that has invested, among other things, in companies in the energy industry. As a result, Warburg Pincus' existing and future portfolio companies which it controls may compete with us for investment or business opportunities. These conflicts of interest may not be resolved in our favor.

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In our amended and restated certificate of incorporation, we have renounced business opportunities that may be pursued by the Partnership or by affiliated stockholders that currently hold a significant amount of our common stock.

In our restated charter and in accordance with Delaware law, we have renounced any interest or expectancy we may have in, or being offered an opportunity to participate in, any business opportunities, including any opportunities within those classes of opportunity currently pursued by the Partnership, presented to Warburg Pincus or any private fund that it manages or advises, their affiliates (other than us and our subsidiaries), their officers, directors, partners, employees or other agents who serve as one of our directors, Merrill Lynch Ventures L.P. 2001, its affiliates (other than us and our subsidiaries) and any portfolio company in which such entities or persons has an equity investment (other than us and our subsidiaries) participates or desires or seeks to participate in and that involves any aspect of the energy business or industry.

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

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

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

Risks Inherent in the Partnership's Business

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

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

The Partnership has a substantial amount of indebtedness. As of December 31, 2012, the Partnership had $620.0 million of borrowings outstanding under the TRP Revolver, $45.3 million of letters of credit outstanding and $534.7 million of additional borrowing capacity under the TRP Revolver. In addition, the Partnership had $1,806.3 million outstanding under its senior unsecured notes, excluding $33.0 million in unamortized discounts. The $1.2 billion TRP Revolver allows it to request increases in commitments up to an additional $300 million. For the years ended December 31, 2012, 2011 and 2010, the Partnership's consolidated interest expense was $116.8 million, $107.7 million and $110.9 million.

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

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

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

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

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

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

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

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

The Partnership has significant exposure to increases in interest rates. As of December 31, 2012, its total indebtedness was $2,426.3 million, excluding $33.0 million in unamortized discounts, of which $1,806.3 million was at fixed interest rates and $620.0 million was at variable interest rates. A one percentage point increase in the interest rate on the Partnership's variable interest rate debt would have increased its consolidated annual interest expense by approximately $6.2 million. As a result of this significant amount of variable interest rate debt, the Partnership's financial condition could be adversely affected by significant increases in interest rates.

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

The Partnership may be able to incur substantial additional indebtedness in the future. As of December 31, 2012, the Partnership had $620.0 million of borrowings outstanding under the TRP Revolver, $45.3 million of letters of credit outstanding and $534.7 million of additional borrowing capacity under the TRP Revolver. The Partnership may be able to incur an additional $300 million of debt under the TRP Revolver if the Partnership requests and is able to obtain commitments for the additional $300 million available under the TRP Revolver. Although the TRP Revolver contains restrictions on the incurrence of additional indebtedness, these restrictions are subject to a number of significant qualifications and exceptions, and any indebtedness incurred in compliance with these restrictions could be substantial. If the Partnership incurs additional debt, the risks associated with its substantial leverage would increase.

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

The credit agreement governing the TRP Revolver, its accounts receivable securitization facility (the "Securitization Facility") and the indentures governing its senior notes (other than its 11¼% Senior Notes due 2017 (the "11¼% Notes")) contain, and any future indebtedness the Partnership incurs will likely contain, a number of restrictive covenants that impose significant operating and financial restrictions, including restrictions on its ability to engage in acts that may be in its best long-term interests. These agreements include covenants that, among other things, restrict the Partnership's ability to:

incur or guarantee additional indebtedness or issue preferred stock;

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

make investments;

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

sell assets, including equity securities of its subsidiaries;

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- engage in affiliate transactions,
- consolidate or merge;
- incur liens;
- prepay, redeem and repurchase certain debt, other than loans under the TRP Revolver;
- make certain acquisitions;
- transfer assets;
- enter into sale and lease back transactions;
- make capital expenditures;
- amend debt and other material agreements; and
- change business activities conducted by it.

In addition, the TRP Revolver requires it to satisfy and maintain specified financial ratios and other financial condition tests. The Partnership's ability to meet those financial ratios and tests can be affected by events beyond its control, and we cannot assure you that the Partnership will meet those ratios and tests.

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

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

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

- the impact of seasonality and weather;
- general economic conditions and economic conditions impacting the Partnership's primary markets;

the economic conditions of the Partnership's customers;

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

the availability of imported natural gas, liquefied natural gas, NGLs and crude oil;

actions taken by foreign oil and gas producing nations;

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the availability of local, intrastate and interstate transportation systems and storage for residue natural gas and NGLs;

the availability and marketing of competitive fuels and/or feedstocks;

the impact of energy conservation efforts; and

the extent of governmental regulation and taxation.

The Partnership's primary natural gas gathering and processing arrangements that expose it to commodity price risk are its percent-of-proceeds arrangements. For the years ended December 31, 2012 and 2011, the Partnership's percent-of-proceeds arrangements accounted for approximately 43% and 40% of its gathered natural gas volume. Under these arrangements, the Partnership generally processes 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 the Partnership's processing facilities. In some percent-of-proceeds arrangements, the Partnership remits to the producer a percentage of an index-based price for residue gas and NGL products, less agreed adjustments, rather than remitting a portion of the actual sales proceeds. Under these types of arrangements, the Partnership's revenues and cash flows increase or decrease, whichever is applicable, as the price of natural gas, NGLs and crude oil fluctuates. 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 the Partnership's operating regions and in other regions from which it sources NGL supplies, its long-term success depends on its ability to obtain new sources of supplies of natural gas, NGLs and crude oil which depends on certain factors beyond its control. Any decrease in supplies of natural gas, NGLs or crude oil could adversely affect the Partnership's business and operating results.

The Partnership's gathering systems are connected to oil and natural gas wells from which production will naturally decline over time, which means that the cash flows associated with these sources of natural gas and crude oil will likely also decline over time. The Partnership's logistics assets are similarly impacted by declines in NGL supplies in the regions in which it operates as well as other regions from which it sources NGLs. To maintain or increase throughput levels on the Partnership's gathering systems and the utilization rate at its processing plants and its treating and fractionation facilities, the Partnership must continually obtain new natural gas, NGL and crude oil supplies. A material decrease in natural gas production from producing areas on which the Partnership relies, as a result of depressed commodity prices or otherwise, could result in a decline in the volume of natural gas or crude oil that it processes, NGL products delivered to its fractionation facilities or crude oil that the Partnership gathers. The Partnership's ability to obtain additional sources of natural gas, NGLs and crude oil depends, in part, on the level of successful drilling and production activity near its gathering systems and, in part, on the level of successful drilling and production in other areas from which it sources NGL and crude oil supplies. The Partnership has no control over the level of such activity in the areas of its operations, the amount of reserves associated with the wells or the rate at which production from a well will decline. In addition, the Partnership has no control over producers or their drilling or production decisions, which are affected by, among other things, prevailing and projected energy prices, demand for hydrocarbons, the level of reserves, geological considerations, governmental regulations, 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 the Partnership's assets, producers may choose not to develop those reserves. For example, current low prices for natural gas combined with relatively high levels of natural gas in storage could result in curtailment or shut-in of natural gas production.

Reductions in exploration and production activity, competitor actions or shut-ins by producers in the areas in which the Partnership operates may prevent it from obtaining supplies of natural gas or crude oil to replace the natural decline in volumes from existing wells, which could result in reduced volumes through its facilities, and reduced utilization of its gathering, treating, processing and fractionation assets.

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

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

In addition, the Partnership may not achieve the expected results of the Badlands acquisition, and any adverse conditions or developments related to the Badlands acquisition may have a negative impact on its operations and financial condition.

Saddle Butte Pipeline LLC ("Saddle Butte"), the entity whose crude oil pipeline and terminal system and natural gas gathering and processing operations the Partnership acquired in the Badlands acquisition, operates its business in geographic regions in which it did not operate prior to the acquisition, including in the Bakken Shale Play. In order to operate effectively in these new regions, the Partnership will need to understand the local market and regulatory environment and identify and retain certain employees from Saddle Butte who are familiar with these markets. If the Partnership is not successful in retaining these employees or operating in these new geographic areas, it may not be able to compete effectively in the new markets or fully realize the expected benefits of the Badlands acquisition.

Any acquisition, including the Badlands 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 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 unknown liabilities;
- limitations on rights to indemnity from the seller in an acquisition or contractors and suppliers in growth projects;

- 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.

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

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

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

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

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

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

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

In addition, the Partnership is experiencing increased competition for the types of assets it contemplates purchasing or developing. Current economic conditions and competition for asset purchases and development opportunities could limit its ability to fully execute its acquisition and growth strategy.

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Demand for propane is seasonal and requires increases in inventory to meet seasonal demand.

Weather conditions have a significant impact on the demand for propane because end users depend on propane principally for heating purposes. Warmer than normal temperatures in one or more regions in which the Partnership operates can significantly decrease the total volume of propane it sells. Lack of consumer demand for propane may also adversely affect the retailers with which the Partnership transacts its wholesale propane marketing operations, exposing the Partnership to retailers' inability to satisfy their contractual obligations to the Partnership.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

NGLs and products produced from NGLs also compete with products from global markets. Any reduced demand or increased supply for ethane, propane, normal butane, isobutane or natural gasoline in the markets the Partnership accesses for any of the reasons stated above could adversely affect demand for the services it provides as well as NGL prices, which would negatively impact its results of operations and financial condition.

The Partnership has significant relationships with CPC as a customer for its marketing and refinery services. In some cases, these agreements are subject to renegotiation and termination rights.

For the years ended December 31, 2012, and 2011, approximately 10% and 12% of the Partnership's consolidated revenues were derived from transactions with CPC. Under many of the Partnership's CPC contracts where it purchases or markets 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 the Partnership or reduces the volumes of NGLs that the Partnership markets on its behalf or to the extent the economic terms of such contracts are changed, the Partnership's revenues and cash available for debt service could decline.

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

We currently own an approximate 14.7% limited partner interest, a 2% general partner interest and the IDRs in the Partnership. The anticipated after-tax economic benefit of our investment in the Partnership depends largely on its being treated as a partnership for federal income tax purposes. A publicly traded partnership such as the Partnership may be treated as a corporation for federal income tax purposes unless it satisfies a "qualifying income" requirement. Based on the Partnership's current operations we believe that the Partnership satisfies the qualifying income requirement and will be treated as a partnership. Failing to meet the qualifying income requirement or a change in current law could cause the Partnership to be treated as a corporation for federal income tax purposes or otherwise subject the Partnership to taxation as an entity. The Partnership has not requested and does not plan to request a ruling from the IRS with respect to its treatment as a partnership for federal income tax purposes.

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

In addition, current law may change so as to cause the Partnership to be treated as a corporation for federal income tax purposes or otherwise subject the Partnership to entity-level taxation for state or local income tax purposes. The present U.S. federal income tax treatment of publicly traded partnerships, including the Partnership, or an investment in the Partnership's common units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. For example, from time to time, members of Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships. One such legislative proposal would eliminate the qualifying income exception to the treatment of all publicly traded partnerships as corporations upon which the Partnership relies for its treatment as a partnership for U.S. federal income tax purposes. We are unable to predict whether any of these changes or other proposals will be reintroduced or will ultimately be enacted. Any such changes could negatively impact the value of our investment in the Partnership's common units. In addition, 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, franchise and other forms of taxation. For example, the Partnership is required to pay Texas franchise tax at a maximum effective rate of 0.7% of its gross income apportioned to Texas in the prior year. Imposition of any similar tax on the Partnership by additional states would reduce the cash available for distribution to Partnership unitholders, including us.

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

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

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

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

The Partnership participates in several majority-owned joint ventures whose corporate governance structures require at least a majority in interest vote to authorize many basic activities and require a greater voting interest (sometimes up to 100%) to authorize more significant activities. Examples of these more significant activities are 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, among others. Without the concurrence of joint venture participants with enough voting interests, the Partnership may be unable to cause any of its joint ventures to take or not take certain actions, even though taking or preventing those actions may be in the best interest of the Partnership or the particular joint venture.

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

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

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

The Partnership's business involves many hazards and operational risks, some of which may not be insured or fully covered by insurance. If a significant accident or event occurs that is not fully insured, if the Partnership fails to recover all anticipated insurance proceeds for significant accidents or events for which it is insured, or if the Partnership fails to rebuild facilities damaged by such accidents or events, its operations and financial results could be adversely affected.

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

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- 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 or construction, farm and utility equipment;

- damage that is the result of the Partnership's negligence or any of its employees' negligence;

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

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

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

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

Pursuant to the Pipeline Safety Improvement Act of 2002, as reauthorized and amended by the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006, the DOT, through the PHMSA, has adopted regulations requiring pipeline operators to develop integrity management programs for transmission pipelines located where a leak or rupture could do the most harm in "high consequence areas," including high population areas, areas that are sources of drinking water, ecological resource areas that are unusually sensitive to environmental damage from a pipeline release and commercially navigable waterways, unless the operator effectively demonstrates by risk assessment that the pipeline could not affect the area. The 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;

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- repair and remediate the pipeline as necessary; and
- implement preventive and mitigating actions.

In addition, states have adopted regulations similar to existing DOT regulations for intrastate gathering and transmission lines. The Partnership currently estimates an annual average cost of $2.1 million between 2013 and 2015 to implement pipeline integrity management program testing along certain segments of its 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 Partnership's ultimate cost of compliance with applicable pipeline integrity management regulations, as the cost will vary significantly depending on the number and extent of any repairs found to be necessary as a result of the pipeline integrity testing. The Partnership will continue its pipeline integrity testing programs to assess and maintain the integrity of its pipelines. The results of these tests could cause the Partnership to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of its pipelines.

Moreover, changes to pipeline safety laws and regulations that result in more stringent or costly safety standards could have a significant adverse effect on the Partnership and similarly situated midstream operators. The 2011 Pipeline Safety Act, among other things, 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 and testing to confirm the material strength of pipe operating above 30% of specified minimum yield strength in high consequence areas. These safety enhancement requirements and other provisions of this act could require the Partnership to install new or modified safety controls, pursue additional capital projects or conduct maintenance programs on an accelerated basis, any or all of which tasks could result in the Partnership incurring increased operating costs that could be significant and have a material adverse effect on its financial position or results of operations.

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

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

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

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

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

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The Partnership's operations are subject to stringent federal, 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 the Partnership's operations including acquisition of a permit before conducting regulated activities, restriction of types, quantities and concentration of materials that can be released into the environment; limitation or prohibition of construction and operating activities in environmentally sensitive areas such as wetlands, urban areas, wilderness regions and other protected areas; requiring capital expenditures to comply with pollution control requirements and imposition of substantial liabilities for pollution resulting from its operations. Numerous governmental authorities, such as the EPA and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring 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 the Partnership's operations due to its handling of natural gas, NGLs, crude oil and other petroleum products, because of air emissions and product-related discharges arising out of its operations, and as a result of historical industry operations and waste disposal practices. For example, an accidental release from one of the Partnership's facilities could subject it to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury, natural resource and property damages and fines or penalties for related violations of environmental laws or regulations. Moreover, stricter laws, regulations or enforcement policies could significantly increase the Partnership's operational or compliance costs and the cost of any remediation that may become necessary. Additionally, environmental groups have, from time to time, advocated increased regulation on the issuance of drilling permits for new wells in areas where the Partnership operates, 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 the Partnership's natural gas customers' operating and compliance costs as well as reduce the rate of production of natural gas or crude oil operators with whom the Partnership has a business relationship, which could have a material adverse effect on its results of operations and cash flows.

Increased regulation of hydraulic fracturing could result in reductions or delays in drilling and completing new oil and natural gas wells, which could adversely impact the Partnership's revenues by decreasing the volumes of natural gas that it gathers, processes and fractionates.

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 federal regulatory authority over hydraulic fracturing involving diesel fuel under the SDWA Underground Injection Control Program and has issued draft guidance documents related to this asserted regulatory authority. In November 2011, the EPA announced its intent to develop and issue regulations under the federal Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing. In addition, from time to time legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. Moreover, some states have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, disclosure or well construction requirements on hydraulic fracturing activities. For example, Texas adopted a law in June 2011 requiring disclosure to the Railroad Commission of Texas and the public of certain information regarding the constituents used in the hydraulic-fracturing process. Adoption of legislation or of any implementing regulations placing restrictions on hydraulic fracturing activities could impose operational delays, increased operating costs and additional regulatory burdens on exploration and production operators, which could reduce their production of natural gas and, in turn, adversely affect the Partnership's revenues and results of operations by decreasing the volumes of natural gas that it gathers, processes and fractionates.

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In addition, several governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administrative-wide review of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a first progress report outlining work currently underway by the agency released on December 21, 2012 and a final report drawing conclusions about hydraulic fracturing on drinking water resources expected to be available for public comment and peer review by 2014. Moreover, the EPA is developing effluent standards for the treatment and disposal of wastewater resulting from hydraulic fracturing activities and plans to propose those standards by 2014. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior have evaluated various other aspects of hydraulic fracturing. These studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms, which events could delay or curtail production of natural gas by exploration and production operators, some of which are the Partnership's customers, and thus reduce demand for its midstream services.

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

VGS is engaged in the business of transporting natural gas in interstate commerce, under authorization granted by and subject to the jurisdiction of the FERC under the NGA. VGS owns and operates a natural gas gathering system extending from South Timbalier Block 135 to an onshore interconnection to a natural gas processing plant owned by VESCO. With the exception of the Partnership's interest in VGS, its operations are generally exempt from FERC regulation under the NGA, but FERC regulation still affects its non-FERC jurisdictional businesses and the markets for products derived from these businesses. The NGA exempts natural gas gathering facilities from regulation by FERC as a natural gas company under the NGA. 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, on-going litigation, so the classification and regulation of the Partnership's gathering facilities are subject to change based on future determinations by FERC, the courts or Congress. In addition, the courts have determined that certain pipelines that would otherwise be subject to the ICA are exempt from regulation by FERC under the ICA as proprietary lines. The classification of a line as a proprietary line is a fact-based determination subject to FERC and court review. Accordingly, the classification and regulation of some of the Partnership's gathering facilities and transportation pipelines may be subject to change based on future determinations by FERC, the courts or Congress.

While the Partnership's natural gas gathering operations are generally exempt from FERC regulation under the NGA, its gas gathering operations may be subject to certain FERC reporting and posting requirements in a given year. FERC has issued a final rule (as amended by orders on rehearing and clarification), Order No. 704, requiring certain participants in the natural gas market, including intrastate pipelines, natural gas gatherers, natural gas marketers and natural gas processors, that engage in a minimum level of natural gas sales or purchases to submit annual reports regarding those transactions to FERC. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order No. 704. Order No. 704 also requires market participants to indicate whether they report prices to any index publishers and, if so, whether their reporting complies with FERC's policy statement on price reporting.

In addition, FERC has issued a final rule (as amended by orders on rehearing and clarification), Order No. 720, requiring major non-interstate pipelines, defined as certain non-interstate pipelines delivering, on an annual basis, more than an average of 50 million MMBtu of gas over the previous three calendar years, to post daily certain information regarding the pipeline's capacity and scheduled flows for each receipt and delivery point that has design capacity equal to or greater than 15,000 MMBtu/d and requiring interstate pipelines 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 with respect to its application to non-interstate pipelines. In December 2011, the Fifth Circuit confirmed that Order No. 720, as clarified, remained applicable to interstate pipelines with respect to posting information regarding the provision of no-notice service. We take the position that at this time the Partnership and its subsidiaries are exempt from this rule.

In addition, FERC recently issued an order extending certain of the open-access requirements including the prohibition on buy/sell arrangements and shipper-must-have-title provisions to include Hinshaw pipelines to the extent such pipelines provide interstate service. However, FERC issued a Notice of Inquiry on October 21, 2010, effectively suspending the recent ruling and requesting comments on whether and how holders of firm capacity on Section 311 and Hinshaw pipelines should be permitted to allow others to make use of their firm interstate capacity, including to what extent buy/sell transactions should be permitted. We have no way to predict with certainty whether and to what extent the Notice of Inquiry will result in a modification to the FERC's previous ruling.

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

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

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

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

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

In December 2009, the EPA published its findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA has adopted rules under the Clean Air Act that requires a reduction in emissions of GHGs from motor vehicles and that requires certain construction and operating permit reviews for GHG emissions from certain large stationary sources. The stationary source final rule addresses the permitting of GHG emissions from stationary sources under the Clean Air Act Prevention of Significant Deterioration ("PSD") construction and Title V operating permit programs, pursuant to which these permit programs have been "tailored" to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. Moreover, because the EPA assumed responsibility for issuing Clean Air Act PSD construction and Title V operating permits for GHG emissions in Texas in December 2010, those two permitting programs are now subject to dual sets of approvals at the state and federal levels. Operators in Texas with stationary sources emitting GHGs in excess of applicable regulatory thresholds must now obtain separate PSD and/or Title V permits from each of the EPA, with respect to GHG emissions, and the TCEQ with respect to all other regulated non-GHG emissions. Facilities required to obtain PSD permits for their GHG emissions will be required to reduce those emissions according to "best available control technology" standards for

GHGs. In addition, the EPA adopted rules requiring the monitoring and reporting of GHG emissions from certain sources, including, among others, onshore and offshore oil and natural gas production facilities and onshore oil and natural gas processing, transmission, storage and distribution facilities on an annual basis, which includes certain of the Partnership's operations.

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In addition, the United States Congress has from time to time considered adopting legislation to reduce emissions of GHGs and almost half of the states have already taken legal measures to reduce emissions of GHGs primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. The adoption of legislation or regulatory programs to reduce emissions of GHGs could require the Partnership to incur increased operating costs or comply with new regulatory or reporting requirements. The division of PSD construction and Title V operating permit authority in Texas between the EPA and TCEQ may cause the Partnership's Texas operations to experience added delays in obtaining permit coverages, which delays may be significant. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the natural gas and NGLs the Partnership processes or fractionates, which could have an adverse effect on its business, financial condition and results of operations.

Pipeline safety legislation and regulations expanding integrity management programs or requiring the use of certain safety technologies could require the Partnership to use more comprehensive and stringent safety controls and subject it to increased capital and operating costs.

The 2011 Pipeline Safety 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, and leak detection system installation. The 2011 Pipeline Safety Act also directs owners and operators of interstate and intrastate gas transmission pipelines to verify their records confirming the maximum allowable pressure of pipelines in certain class locations and high consequence areas, requires promulgation of regulations for conducting tests to confirm the material strength of pipe operating above 30% of specified minimum yield strength in high consequence areas, and 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 could require the Partnership to install new or modified safety controls, pursue additional capital projects, decrease its pipeline operating pressures, or conduct maintenance programs on an accelerated basis, any or all of which tasks could result in the Partnership incurring increased operating costs that could be significant and have a material adverse effect on its results of operations or financial position.

The recent adoption of derivatives legislation by the United States Congress could have an adverse effect on the Partnership's ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with its business.

The United States Congress adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as the Partnership, that participate in that market. The new legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"), was signed into law by the President on July 21, 2010, and requires the CFTC and the SEC to promulgate rules and regulations implementing the new legislation. The financial reform legislation and subsequent rulemaking may require the Partnership to comply with margin requirements and with certain clearing and trade-execution requirements in connection with its derivative activities, although the application of those provisions to the Partnership is uncertain at this time. The financial reform legislation may also require counterparties to the Partnership's derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect the Partnership's available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks the Partnership encounters, reduce its ability to monetize or restructure its existing derivative contracts and increase its exposure to less creditworthy counterparties. If the Partnership reduces its use of derivatives as a result of the legislation and regulations, its results of operations may become more volatile and its cash flows may be less predictable, which could adversely affect its ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. The Partnership's revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on the Partnership, its financial condition and its results of operations.

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The Partnership's interstate common carrier liquids pipeline is regulated by the FERC.

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

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

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

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

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

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.

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PART II

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

Market Information

Our common stock has been listed on the New York Stock Exchange ("NYSE") since December 7, 2010 under the symbol "TRGP." The following table sets forth the high and low sales prices of the common stock at the end of each subsequent quarter, as reported by the NYSE through December 31, 2012 and the amount of cash dividends declared since our IPO.

Quarter Ended	Stock Prices High	Stock Prices Low	Dividends Declared	
December 31, 2012	$ 53.38	$ 45.74	$ 0.45750	
September 30, 2012	51.43	41.46	0.42250	
June 30, 2012	49.91	39.89	0.39375	
March 31, 2012	48.28	38.70	0.36500	
December 31, 2011	41.12	26.76	0.33625	
September 30, 2011	34.91	26.01	0.30750	
June 30, 2011	36.73	29.44	0.29000	
March 31, 2011	36.70	26.51	0.27250	
December 31, 2010	28.40	23.50	0.06160	(1)

(1) Represents a prorated dividend for the portion of the fourth quarter of 2010 that the Company was public.

As of February 11, 2013, there were approximately 250 stockholders of record of our common stock. This number does not include stockholders whose shares are held in trust by other entities. The actual number of stockholders is greater than the number of holders of record.

Stock Performance Graph

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

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

Our Dividend Policy

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

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

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

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

The Partnership's Cash Distribution Policy

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 the general partner to:

- provide for the proper conduct of the Partnership's business including reserves for future capital expenditures and for anticipated future credit needs;
-

comply with applicable law or any loan agreements, security agreements, mortgages, debt instruments or other agreements binding on the Partnership and its subsidiaries; or

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

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

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The actual cash distributions paid by the Partnership to its partners occur within 45 days after the end of each quarter. Since the second quarter of 2007, the Partnership has increased its quarterly cash distribution fifteen times. During that time period, the Partnership has increased its quarterly distribution by 101% from $0.3375 per common unit, or $1.35 on an annualized basis, to $0.68 per common unit, or $2.72 on an annualized basis.

For a discussion of restrictions on our and our subsidiaries' ability to pay dividends or make distributions, please see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Credit Facilities and Long-Term Debt" and Note 10 "Debt Obligations" to our consolidated financial statements beginning on page F-1 of this Form 10-K.

Recent Sales of Unregistered Stock

None.

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

None.

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Item 6. Selected Financial Data.

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

	2012	2011	2010	2009	2008
	(In millions, except per share amounts)				
Statement of operations data:					
Revenues	$5,885.7	$6,994.5	$5,476.1	$4,542.3	$7,998.9
Income from operations	336.3	351.1	196.1	217.2	234.5
Net income	159.3	215.4	63.3	79.1	134.4
Net income (loss) attributable to Targa Resources Corp.	38.1	30.7	(15.0)	29.3	37.3
Dividends on Series B preferred stock	-	-	(9.5)	(17.8)	(16.8)
Net income (loss) available to common shareholders	38.1	30.7	(202.3)	-	-
Net income (loss) per common share - basic	0.93	0.75	(30.94)	-	-
Net income (loss) per common share - diluted	0.91	0.74	(30.94)	-	-
Balance sheet data (at end of period):					
Total assets	$5,105.0	$3,831.0	$3,393.8	$3,367.5	$3,641.8
Long-term debt	2,475.3	1,567.0	1,534.7	1,593.5	1,976.5
Convertible cumulative participating series B preferred stock	-	-	-	308.4	290.6
Total owners' equity	1,753.4	1,330.7	1,036.1	754.9	822.0
Other:					
Dividends declared per share	$1.63875	$1.2063	$0.0616	N/A	N/A
Dividends paid on series B preferred shares	$-	$-	$238.0	$-	$-

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our historical financial statements and notes included in Part IV of this Annual Report. Also, the Partnership files a separate Annual Report on Form 10-K with the SEC.

Overview

Financial Presentation

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

As a result of the conveyance of all of our remaining operating assets to the Partnership in September 2010, we have no separate, direct operating activities apart from those conducted by the Partnership. As such, our cash inflows will primarily consist of cash distributions from our interests in the Partnership. The Partnership is required to distribute all available cash at the end of each quarter after establishing reserves to provide for the proper conduct of its business or to provide for future distributions.

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

- noncontrolling interests in the Partnership;
- our separate debt obligations;
- certain general and administrative costs applicable to us as a separate public company;
- certain non-operating assets and liabilities that we retained; and
- federal income taxes.

Our Operations

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

The Partnership's Operations

The Partnership is a leading provider of midstream natural gas, NGLs, terminaling and crude oil gathering services in the United States. It is engaged in the business of:

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

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

The Partnership's Gathering and Processing division includes assets used in the gathering of natural gas produced from oil and gas wells and processing this raw natural gas into merchantable natural gas by extracting NGLs and removing impurities. 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, the Field Gathering and Processing segment's assets now include the Badlands crude oil and natural gas gathering, terminaling and processing assets in North Dakota as well. However, because the Badlands acquisition closed on December 31, 2012, the Badlands assets had no operational impact for 2012 other than transaction costs related to the acquisition. The Coastal Gathering and Processing segment's assets are located in the onshore and near offshore regions of the Louisiana Gulf Coast and the Gulf of Mexico.

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

The Partnership's Logistics Assets segment is involved in transporting, storing and fractionating mixed NGLs; storing, terminaling and transporting finished NGLs; and storing and terminaling refined petroleum products and crude oil. These assets are generally connected to, and supplied in part by, the Partnership's Gathering and Processing segments and are predominantly located in Mont Belvieu, Texas and Southwestern Louisiana. This segment includes the activities associated with the Partnership's 2011 acquisitions of refined petroleum products and crude oil storage and terminaling facilities.

The Partnership's Marketing and Distribution segment covers activities required to distribute and market raw and finished NGLs and all natural gas marketing activities. It includes (1) marketing the Partnership's own NGL production and purchasing NGL products 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; and (4) marketing natural gas available to the Partnership from its Gathering and Processing division and the purchase and resale and other value added activities related to third-party natural gas in selected United States markets.

Other contains the results of the Partnership's commodity hedging activities included in operating margin.

Factors That Significantly Affect Our Results

Our cash flow and resulting ability to pay dividends will be dependent upon the Partnership's ability to make distributions to its partners, including us. The actual amount of cash that the Partnership will have available for distributions will depend primarily on the amount of cash that it generates from its operations.

As of February 15, 2013, our interests in the Partnership consist of the following:

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

- all of the outstanding IDRs; and
- 12,945,659 of the 101,788,617 outstanding common units of the Partnership, representing a 12.7% limited partnership interest.

Factors That Significantly Affect the Partnership's Results

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

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Volumes

In the Partnership's gathering and processing operations, plant inlet volumes and capacity utilization rates generally are driven by wellhead production, its 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 its operations. The factors that impact the gathering and processing volumes also impact the total volumes that flow to the Partnership's Downstream Business. In addition, fractionation volumes are also affected by the location of the resulting mixed NGLs, available pipeline capacity to transport NGLs to the Partnership's fractionators and the Partnership's 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)
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
2010			
4th Quarter	$3.80	$1.13	$85.26
3rd Quarter	4.38	0.94	76.21
2nd Quarter	4.09	1.00	78.05
1st Quarter	5.30	1.13	78.88
2010 Average	$4.39	$1.05	$79.60

(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.

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Contract Terms, Contract Mix and the Impact of Commodity Prices

Because of the significant volatility of natural gas and NGL prices, the contract mix of the Partnership's gathering and processing segment can also have a significant impact on its profitability, especially those contracts that create exposure to changes in energy prices ("equity volumes"). Set forth below is a table summarizing the mix of the Partnership's gathering and processing contracts for 2012 and the potential impacts of commodity prices on operating margins:

Contract Type	Percent of Throughput	Impact of Commodity Prices
Percent-of-Proceeds/Percent-of-Liquids	43%	Decreases in natural gas and or NGL prices generate decreases in operating margins.
Fee-Based	3%	No direct impact from commodity price movements.
Wellhead Purchases/Keep-whole	21%	Increases in natural gas prices relative to NGL prices generate decreases in operating margin.
Hybrid	33%	In periods of favorable processing economics (1), similar to percent-of-liquids or to wellhead purchases/keep-whole in some circumstances, if economically advantageous to the processor. In periods of unfavorable processing economics, similar to fee-based.

(1) Favorable processing economics typically occur when processed NGLs can be sold, after allowing for processing costs, at a higher value than natural gas on a Btu equivalent basis.

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

The contract terms and contract mix of the Downstream Business can also have a significant impact on its 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. Currently, demand for fractionation services is near existing industry capacity, rates have increased, contract lengths have increased and reservation fees are required. These fractionation contracts in the logistics assets segment are primarily fee-based arrangements while the marketing and distribution segment includes both fee-based and percent-of-proceeds contracts.

Impact of the Partnership's Commodity Price Hedging Activities

In an effort to reduce the variability of its cash flows, the Partnership has hedged the commodity price associated with a portion of its expected natural gas equity volumes through 2015 and NGL and condensate equity volumes through 2014 by entering into derivative financial instruments including swaps and purchased puts (or floors). With these arrangements, the Partnership has attempted to mitigate its exposure to commodity price movements with respect to its forecasted volumes for these periods. The Partnership also actively manages the Downstream Business product inventory and other working capital levels to reduce exposure to changing NGL prices. For additional information regarding the Partnership's hedging activities, see "Item 7A. Quantitative and Qualitative Disclosures About Market

Risk — Commodity Price Risk.”

Operating Expenses

Variable costs such as fuel, utilities, power, service and repairs can impact the Partnership’s results as volumes fluctuate through its systems. Continued expansion of existing assets will also give rise to additional operating expenses, which will affect the Partnership’s results.

General and Administrative Expenses

Under the Omnibus Agreement we have with the Partnership, which initial term expires in April 2013, we provide general and administrative and other services associated with (1) the Partnership’s existing assets and any future conveyances by us and (2) subject to mutual agreement, future acquisitions from third parties. Since October 1, 2010, after the final conveyance of assets by us to the Partnership, substantially all of our general and administrative costs have been and, so long as our only cash generating assets are ownership interests in the Partnership, will continue to be allocated to the Partnership, other than our direct costs of being a public reporting company. The Partnership agreement will govern these matters after the Omnibus Agreement expires. See “Item 13. Certain Relationships and Related Transactions, and Director Independence – Omnibus Agreement.”

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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 the Partnership's Services

Fluctuations in energy prices can affect production rates and investments by third parties in the development of oil and natural gas reserves. Generally, drilling and production activity will increase as energy prices increase. We believe that the current strength of oil, condensate and NGL prices as compared to natural gas prices has caused producers in and around the Partnership's 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 inlet volumes in the Field Gathering and Processing segment over the next several years. While we expect demand for the Partnership's 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 the Partnership's 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 the Partnership's terminaling and storage services in the Downstream Business. Producer activity in areas rich in oil, condensate and NGLs is currently generating increased demand for the Partnership's fractionation services and for related fee-based services provided by the 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

Current forward commodity prices as of December 31, 2012 show natural gas and crude oil prices strengthening while NGL prices remain relatively flat. Various industry commodity price forecasts based on fundamental analysis may differ significantly from forward market prices. Both are subject to change due to multiple factors. There has been, and we believe there will continue to be, significant volatility in commodity prices and in the relationships among NGL, crude oil and natural gas prices. In addition, the volatility and uncertainty of natural gas, crude oil and NGL prices impact drilling, completion and other investment decisions by producers and ultimately supply to the Partnership's systems.

The Partnership's operating income generally improves in an environment of higher natural gas, NGL and condensate prices, primarily as a result of its percent-of-proceeds contracts. The Partnership's processing profitability is largely dependent upon pricing, the supply of and market demand for natural gas, NGLs and condensate, which are beyond its control and have been volatile. Recent weak economic conditions have negatively affected the pricing and market demand for natural gas, NGLs and condensate, which caused a reduction in profitability of the Partnership's processing operations. In a declining commodity price environment, without taking into account the Partnership's hedges, it will realize a reduction in cash flows under its percent-of-proceeds contracts proportionate to average price declines. The Partnership has attempted to mitigate its exposure to commodity price movements by entering into hedging arrangements. For additional information regarding hedging activities, see "Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk."

Volatile Capital Markets

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

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Increased Regulation

Additional regulation in various areas has the potential to materially impact the Partnership's operations and financial condition. For example, increased regulation of hydraulic fracturing used by producers may cause reductions in supplies of natural gas and of NGLs 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 the Partnership's revenues by decreasing the volumes of natural gas that it gathers, processes and fractionates." Similarly, the forthcoming rules and regulations of the CFTC may limit the Partnership's ability or increase the cost to use derivatives, which could create more volatility and less predictability in its results of operations. Please read "Risk Factors—the recent adoption of derivatives legislation by the United States Congress could have an adverse effect on the Partnership's ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with its business."

How We Evaluate Our Operations

Our consolidated operations include the operations of the Partnership due to our ownership and control of the general partner. We currently have no separate, direct operating activities from those conducted by the Partnership. Our financial results differ from the Partnership's due to the financial effects of: noncontrolling interests in the Partnership, our separate debt obligations, certain non-operating costs associated with assets and liabilities that we retained and were not included in asset conveyances to the Partnership, and certain general and administrative costs applicable to us as a separate public company. Management's primary measure of analyzing our performance is the non-GAAP measure distributable cash flow.

Distributable Cash Flow

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

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

The GAAP measure most directly comparable to distributable cash flow is net income. Distributable cash flow should not be considered as an alternative to GAAP net income. Distributable cash flow is not a presentation made in accordance with GAAP and has important limitations as an analytical tool. Investors should not consider distributable cash flow in isolation or as a substitute for analysis of our results as reported under GAAP. Because distributable cash flow excludes some, but not all, items that affect net income and is defined differently by different companies in our industry, our definition of distributable cash flow may not be comparable to similarly titled measures of other companies, thereby diminishing its utility.

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Our Non-GAAP Measures

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

	2012	2011
Targa Resources Corp. Distributable Cash Flow		
Distributions declared by Targa Resources Partners LP associated with:		
General Partner Interests	$6.2	$4.8
Incentive Distribution Rights	63.3	34.4
Common Units	33.8	27.7
Total distributions declared by Targa Resources Partners LP	103.3	66.9
Income (expenses) of TRC Non-Partnership		
General and administrative expenses	(8.2)	(8.3)
Interest expense, net	(4.0)	(4.0)
Current cash tax expense (1)	(20.8)	(7.4)
Taxes funded with cash on hand (2)	8.7	10.1
Other income (expense)	(0.7)	2.9
Distributable cash flow	$78.3	$60.2

(1) Excludes $4.7 million of non-cash current tax expense arising from amortization of deferred long-term tax assets from drop down gains realized for tax purposes and paid in 2010 for the years ended December 31, 2012 and 2011.
(2) Current period portion of amount established at our IPO to fund taxes on deferred gains related to drop down transactions that were treated as sales for income tax purposes.

	2012	2011
Reconciliation of net income attributable to Targa Resources Corp. to Distributable Cash Flow		
Net income of Targa Resources Corp.	$159.3	$215.4
Less: Net income of Targa Resources Partners LP	(203.2)	(245.5)
Net loss for TRC Non-Partnership	(43.9)	(30.1)
Plus: TRC Non-Partnership income tax expense	32.7	22.3
Plus: Distributions from the Partnership	103.3	66.9
Plus: Non-cash loss (gain) on hedges	(2.2)	(4.4)
Plus: Loss on early debt extinguishment	0.2	-
Plus: Depreciation - Non-Partnership assets	0.3	2.8
Less: Current cash tax expense (1)	(20.8)	(7.4)
Plus: Taxes funded with cash on hand (2)	8.7	10.1
Distributable cash flow	$78.3	$60.2

(1) Excludes $4.7 million of non-cash current tax expense arising from amortization of deferred long-term tax assets from drop down gains realized for tax purposes and paid in 2010 for the years ended December 31, 2012 and 2011.
(2) Current period portion of amount established at our IPO to fund taxes on deferred gains related to drop down transactions that were treated as sales for income tax purposes.

How We Evaluate the Partnership's Operations

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

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The Partnership's profitability is also impacted by fee-based revenues. The Partnership's growth strategy, based on expansion of existing facilities as well as third-party acquisitions of businesses and assets, is resulting in an increasing percentage of assets that generate fee-based revenues. Fixed fees for services such as fractionation, storage and terminaling are not directly tied to changes in market prices for commodities.

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

Throughput Volumes, Facility Efficiencies and Fuel Consumption

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

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

As part of monitoring the efficiency of its operations, the Partnership measures the difference between the volume of natural gas received at the wellhead or central delivery points on its gathering systems and the volume received at the inlet of its processing plants as an indicator of fuel consumption and line loss. The Partnership also tracks the difference between the volume of natural gas received at the inlet of the processing plant and the NGLs and residue gas produced at the outlet of such plant to monitor the fuel consumption and recoveries of the facilities. Similar tracking is performed for its logistics assets. These volume, recovery and fuel consumption measurements are an important part of the Partnership's operational efficiency analysis.

Operating Expenses

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

Capital Expenditures

Capital projects associated with growth and maintenance projects are closely monitored. Return on investment is analyzed before a capital project is approved, and spending is closely monitored throughout the development of the project. The Partnership has seen a substantial increase in its total capital spent over the last three years and currently has significant internal growth projects that it closely monitors.

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Gross Margin

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

Operating Margin

The Partnership defines operating margin as gross margin less operating expenses. Operating margin is an important performance measure of the core profitability of 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 the Partnership's assets without regard to financing methods, capital structure or historical cost basis;

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

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

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

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

Adjusted EBITDA

The Partnership defines Adjusted EBITDA as net income before: interest; income taxes; depreciation and amortization; gains or losses on debt repurchases and redemptions, early debt extinguishments and asset disposals; and non-cash risk management activities related to derivative instruments. Adjusted EBITDA is used as a supplemental financial measure by the Partnership and by external users of our financial statements such as investors, commercial banks and others.

The economic substance behind the Partnership's use of Adjusted EBITDA is to measure the ability of its assets to generate cash sufficient to pay interest costs, support its indebtedness and make distributions to its investors.

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. 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.

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

Distributable Cash Flow

The Partnership defines distributable cash flow as net income attributable to Targa Resources Partners LP plus depreciation and amortization, deferred taxes and amortization of debt issue costs included in interest expense, adjusted for non-cash losses (gains) on mark-to-market derivative contracts, debt repurchases and redemptions, early debt extinguishments and asset disposals, less maintenance capital expenditures (net of any reimbursements of project costs). This measure includes any impact of noncontrolling interests.

Distributable cash flow is a significant performance metric used by the Partnership and by external users of the Partnership's financial statements, such as investors, commercial banks and research analysts, to compare basic cash flows generated by the Partnership (prior to the establishment of any retained cash reserves by the board of directors of its general partner) to the cash distributions the Partnership expects to pay the Partnership's unitholders. Using this metric, the Partnership's management and external users of its financial statements can quickly compute the coverage ratio of estimated cash flows to cash distributions. Distributable cash flow is also an important financial measure for the Partnership's unitholders since it serves as an indicator of the Partnership's success in providing a cash return on investment. Specifically, this financial measure indicates to investors whether or not the Partnership is generating cash flow at a level that can sustain or support an increase in the Partnership's quarterly distribution rates. Distributable cash flow is also a quantitative standard used throughout the investment community with respect to publicly-traded partnerships and limited liability companies because the value of a unit of such an entity is generally determined by the unit's yield (which in turn is based on the amount of cash distributions the entity pays to a unitholder).

Distributable cash flow is a non-GAAP financial measure. The GAAP measure most directly comparable to distributable cash flow is net income attributable to Targa Resources Partners LP. Distributable cash flow should not be considered as an alternative to GAAP net income attributable to Targa Resources Partners LP. It has important limitations as an analytical tool. Investors should not consider distributable cash flow in isolation or as a substitute for analysis of 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 the Partnership's 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.

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Non-GAAP Financial Measures of the Partnership

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

	2012	2011	2010
		(In millions)	
Reconciliation of Targa Resources Partners LP gross margin and operating margin to net income:			
Gross margin	$1,004.7	$948.1	$771.3
Operating expenses	(313.0)	(287.0)	(258.6)
Operating margin	691.7	661.1	512.7
Depreciation and amortization expenses	(197.3)	(178.2)	(176.2)
General and administrative expenses	(131.6)	(127.8)	(122.4)
Interest expense, net	(116.8)	(107.7)	(110.8)
Income tax expense	(4.2)	(4.3)	(4.0)
Loss on sale or disposal of assets	(15.6)	(0.2)	-
Loss on debt redemption and early debt extinguishments	(12.8)	-	-
Other, net	(10.2)	2.6	34.7
Targa Resources Partners LP Net income	$203.2	$245.5	$134.0

	2012	2011	2010
		(In millions)	
Reconciliation of net cash provided by Targa Resources Partners LP operating activities to Adjusted EBITDA:			
Net cash provided by operating activities	$465.4	$400.9	$367.9
Net income attributable to noncontrolling interests	(28.6)	(41.0)	(24.9)
Interest expense, net (1)	99.2	95.3	74.8
Loss on debt redemption and early debt extinguishments	(12.8)	-	-
Current income tax expense	2.5	3.5	2.8
Other (2)	(6.4)	7.9	(11.4)
Changes in operating assets and liabilities which used (provided) cash:			
Accounts receivable and other assets	(96.1)	150.3	71.2
Accounts payable and other liabilities	91.7	(126.1)	(84.3)
Targa Resources Partners LP Adjusted EBITDA	$514.9	$490.8	$396.1

(1) Net of amortization of debt issuance costs, discount and premium included in interest expense of $17.6 million for 2012; $12.4 million for 2011; and $6.6 million for 2010. Excludes affiliate and allocated interest expense.

(2) Includes equity earnings from unconsolidated investments – net of distributions, accretion expense associated with asset retirement obligations, amortization of stock based compensation, loss on sale or disposal of assets, loss on a debt redemption and loss on early debt extinguishments.

	2012	2011	2010
		(In millions)	
Reconciliation of net income attributable to Targa Resources Partners LP to Adjusted EBITDA:			
Net income attributable to Targa Resources Partners LP	$174.6	$204.5	$109.1
Add:			
Interest expense, net (1)	116.8	107.7	110.8
Income tax expense	4.2	4.3	4.0
Depreciation and amortization expenses	197.3	178.2	176.2
Loss on sale or disposal of assets	15.6	-	-
Loss on debt redemption and early debt extinguishments	12.8	-	-
Risk management activities	5.4	7.2	6.4
Noncontrolling interests adjustment (2)	(11.8)	(11.1)	(10.4)
Targa Resources Partners LP Adjusted EBITDA	$514.9	$490.8	$396.1

(1) Includes affiliate and allocated interest expense.
(2) Noncontrolling interest portion of depreciation and amortization expenses.

	2012	2011	2010
		(In millions)	
Reconciliation of net income attributable to Targa Resources Partners LP to distributable cash flow:			
Net income attributable to Targa Resources Partners LP	$174.6	$204.5	$109.1
Affiliate and allocated interest expense	-	-	29.4
Depreciation and amortization expenses	197.3	178.2	176.2
Deferred income tax expense	1.7	0.8	1.2
Amortization in interest expense	17.6	12.4	6.1
Loss on debt redemption and early debt extinguishment	12.8	-	-
Loss on sale or disposal of assets	15.6	-	-
Risk management activities	5.4	7.2	6.4
Maintenance capital expenditures	(67.6)	(81.8)	(50.4)
Other (1)	(3.5)	15.4	(1.0)
Targa Resources Partners LP distributable cash flow	$353.9	$336.7	$277.0

(1) Includes reimbursements of certain environmental maintenance capital expenditures by us and the noncontrolling interest portion of maintenance capital expenditures, depreciation and amortization expenses.

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Financial Information – Partnership versus Non-Partnership

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

Balance Sheets – Partnership versus Non-Partnership

	December 31, 2012			December 31, 2011		
	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
	(In millions)					
ASSETS						
Current assets:						
Cash and cash equivalents (1)	$76.3	$68.0	$ 8.3	$145.8	$55.6	$ 90.2
Trade receivables, net	514.9	514.9	-	575.7	575.9	(0.2)
Inventory	99.4	99.4	-	92.2	92.1	0.1
Deferred income taxes (2)	-	-	-	0.1	-	0.1
Assets from risk management activities	29.3	29.3	-	41.0	41.0	-
Other current assets (1)	13.4	3.3	10.1	11.7	2.7	9.0
Total current assets	733.3	714.9	18.4	866.5	767.3	99.2
Property, plant and equipment, at cost (1)	4,708.0	4,701.2	6.8	3,821.1	3,786.9	34.2
Accumulated depreciation	(1,170.0)	(1,168.0)	(2.0)	(1,001.6)	(980.8)	(20.8)
Property, plant and equipment, net	3,538.0	3,533.2	4.8	2,819.5	2,806.1	13.4
Long-term assets from risk management activities	5.1	5.1	-	10.9	10.9	-
Other intangible assets, net	680.8	680.8	-	1.4	1.4	-
Other long-term assets (3)	147.8	91.7	56.1	132.7	72.3	60.4
Total assets	$5,105.0	$5,025.7	$ 79.3	$3,831.0	$3,658.0	$ 173.0
LIABILITIES AND OWNERS' EQUITY						
Current liabilities:						
Accounts payable and accrued liabilities (4)	$679.0	$639.8	$ 39.2	$700.0	$647.8	$ 52.2
Affiliate payable (receivable) (5)	-	61.4	(61.4)	-	60.0	(60.0)
Deferred income taxes (2)	0.2	-	0.2	-	-	-
Liabilities from risk management activities	7.4	7.4	-	41.1	41.1	-

Total current liabilities	686.6	708.6	(22.0)	741.1	748.9	(7.8)
Long-term debt (6)	2,475.3	2,393.3	82.0	1,567.0	1,477.7	89.3
Long-term liabilities from risk management activities	4.8	4.8	-	15.8	15.8	-
Deferred income taxes (2)	131.2	11.2	120.0	120.5	9.5	111.0
Other long-term liabilities (7)	53.7	47.7	6.0	55.9	44.4	11.5
Total liabilities	3,351.6	3,165.6	186.0	2,500.3	2,296.3	204.0
Total owners' equity	1,753.4	1,860.1	(106.7)	1,330.7	1,361.7	(31.0)
Total liabilities and owners' equity	$5,105.0	$5,025.7	$ 79.3	$3,831.0	$3,658.0	$ 173.0

The major Non-Partnership balance sheet items relate to:

(1) Corporate assets consisting of cash, administrative property and equipment, and prepaid insurance, as applicable.

(2) Current and long-term deferred income tax balances.

(3) Long-term tax assets primarily related to gains on 2010 dropdown transactions recognized as sales of assets for tax purposes.

(4) Accrued current employee liabilities related to payroll and incentive compensation plans and taxes payable.

(5) Intercompany receivable with the Partnership related to the ongoing execution of the Omnibus Agreement.

(6) Long-term debt obligations of TRC and TRI.

(7) Long-term liabilities related to incentive compensation plans and deferred rent related to the headquarters office lease.

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Results of Operations – Partnership versus Non-Partnership

	2012			2011			2010		
	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
	(In millions)								
Revenues (1)	$5,885.7	$5,883.6	$2.1	$6,994.5	$6,987.1	$7.4	$5,476.1	5,467.0	$9.1
Costs and Expenses:									
Product purchases	4,879.0	4,878.9	0.1	6,039.0	6,039.0	-	4,695.5	4,695.7	(0.2)
Operating expenses	313.1	313.0	0.1	287.1	287.0	0.1	259.3	258.6	0.7
Depreciation and amortization (2)	197.6	197.3	0.3	181.0	178.2	2.8	185.5	176.2	9.3
General and administrative (3)	139.8	131.6	8.2	136.1	127.8	8.3	144.4	122.4	22.0
Other operating (income) expense	19.9	19.9	-	0.2	0.2	-	(4.7)	(3.3)	(1.4)
Income from operations	336.3	342.9	(6.6)	351.1	354.9	(3.8)	196.1	217.4	(21.3)
Other income (expense):									
Interest expense, net - third party (4)	(120.8)	(116.8)	(4.0)	(111.7)	(107.7)	(4.0)	(110.9)	(81.4)	(29.5)
Interest expense - intercompany (5)	-	-	-	-	-	-	-	(29.4)	29.4
Equity earnings	1.9	1.9	-	8.8	8.8	-	5.4	5.4	-
Loss on debt redemption (4)	(11.1)	(11.1)	-	-	-	-	(17.4)	-	(17.4)
Gain (loss) on early debt extinguishment (4)	(1.7)	(1.7)	-	-	-	-	12.5	-	12.5
Gain (loss) on mark-to-market derivative instruments	-	-	-	(5.0)	(5.0)	-	(0.4)	26.0	(26.4)
Other income (expense)	(8.4)	(7.8)	(0.6)	(1.2)	(1.2)	-	0.5	-	0.5
Income (loss) before income taxes	196.2	207.4	(11.2)	242.0	249.8	(7.8)	85.8	138.0	(52.2)
Income tax expense	(36.9)	(4.2)	(32.7)	(26.6)	(4.3)	(22.3)	(22.5)	(4.0)	(18.5)
Net income (loss)	$159.3	$203.2	$(43.9)	$215.4	$245.5	$(30.1)	$63.3	$134.0	$(70.7)
Less: Net income attributable to	121.2	28.6	92.6	184.7	41.0	143.7	78.3	24.9	53.4

noncontrolling interests (6)									
Net income (loss) after noncontrolling interests	$38.1	$174.6	$(136.5)	$30.7	$204.5	$(173.8)	$(15.0)	$109.1	$(124.1)

The major Non-Partnership results of operations relate to:

(1) Business interruption revenues of $3.0 million and $6.0 million for the years ended December 31, 2011 and 2010 and amortization of Other comprehensive income ("OCI") related to Versado hedges dropped down to the Partnership, and OCI related to terminated hedges.
(2) Depreciation on assets excluded from drop down transactions and corporate administrative assets.
(3) General and administrative expenses retained by TRC related to its status as a public entity.
(4) Interest expense and other gains and losses related to TRC and TRI debt obligations.
(5) Interest on pre-drop down intercompany debt obligations.
(6) TRC noncontrolling interest in the Partnership.

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Statements of Cash Flows – Partnership versus Non-Partnership

	2012			2011			2010		
	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
Cash flows from operating activities					(In millions)				
Net income (loss)	$159.3	$203.2	$(43.9)	$215.4	$245.5	$(30.1)	$63.3	$134.0	$(70.7)
Adjustments to reconcile net income to net cash provided by operating activities:									
Amortization in interest expense	18.2	17.6	0.6	13.0	12.4	0.6	9.4	6.6	2.8
Paid-in-kind interest expense	-	-	-	-	-	-	10.9	-	10.9
Compensation on equity grants	17.5	3.6	13.9	15.2	1.5	13.7	13.4	0.4	13.0
Interest expense on affiliate and allocated indebtedness (1)	-	-	-	-	-	-	-	29.4	(29.4)
Depreciation and amortization expense (2)	197.6	197.3	0.3	181.0	178.2	2.8	174.7	171.3	3.4
Asset impairment charges	-	-	-	-	-	-	10.8	4.9	5.9
Accretion of asset retirement obligations	4.0	3.9	0.1	3.6	3.6	-	3.2	3.2	-
Deferred income tax expense (3	9.0	1.7	7.3	12.3	0.8	11.5	33.1	1.2	31.9
Equity earnings, net of distributions (4)	-	-	-	(0.4)	(0.4)	-	-	-	-
Risk management activities (5)	3.6	5.3	(1.7)	(21.2)	(16.7)	(4.5)	29.9	3.8	26.1
Loss (gain) on sale of assets	15.6	15.6	-	0.2	0.2	-	(1.5)	-	(1.5)
Loss on debt redemption	11.1	11.1	-	-	-	-	17.4	-	17.4
	1.7	1.7	-	-	-	-	(12.5)	-	(12.5)

Loss (gain) on early debt extinguishment									
Payments of interest on Holdco loan facility	-	-	-	-	-	-	(0.9)	-	(0.9)
Changes in operating assets and liabilities: (6)	(9.4)	4.4	(13.8)	(39.8)	(24.2)	(15.6)	(146.0)	13.1	(159.1)
Net cash provided by (used in) operating activities	428.2	465.4	(37.2)	379.3	400.9	(21.6)	205.2	367.9	(162.7)
Cash flows from investing activities									
Outlays for property, plant and equipment (2)	(582.7)	(582.3)	(0.4)	(331.9)	(328.7)	(3.2)	(139.3)	(137.0)	(2.3)
Business acquisitions, net of cash acquired	(996.2)	(996.2)	-	(156.5)	(156.5)	-	-	-	-
Investment in unconsolidated affiliate	(16.8)	(16.8)	-	(21.2)	(21.2)	-	-	-	-
Return of capital from unconsolidated affiliate (4)	0.5	0.5	-	-	-	-	3.3	3.3	-
Other	4.5	1.0	3.5	0.3	0.3	-	4.7	2.1	2.6
Net cash provided by (used in) investing activities	(1,590.7)	(1,593.8)	3.1	(509.3)	(506.1)	(3.2)	(131.3)	(131.6)	0.3
Cash flows from financing activities									
Loan Facilities - Partnership:									
Borrowings	2,595.0	2,595.0	-	2,112.0	2,112.0	-	1,593.1	1,593.1	-
Repayments	(1,690.7)	(1,690.7)	-	(2,082.0)	(2,082.0)	-	(1,057.0)	(1,057.0)	-
Repayment of affiliated indebtedness (1)	-	-	-	-	-	-	-	(737.7)	737.7
Loan Facilities - Non-Partnership:									
Borrowings (7)	90.0	-	90.0	-	-	-	495.0	-	495.0
Repayments (7)	(96.8)	-	(96.8)	-	-	-	(1,087.4)	-	(1,087.4)
	(16.1)	(15.2)	(0.9)	(6.2)	(6.2)	-	(39.6)	(20.2)	(19.4)

Costs incurred in connection with financing arrangements (7)									
Proceeds from sale of common units of the Partnership	493.5	554.5	(61.0)	298.0	304.1	(6.1)	224.4	-	224.4
Distributions to owners (8)	(211.5)	(303.8)	92.3	(196.2)	(256.6)	60.4	(136.9)	(183.1)	46.2
Dividends to common and common equivalent shareholders	(62.2)	-	(62.2)	(38.2)	-	(38.2)	(210.1)	-	(210.1)
Repurchase of common stock (9)	(9.5)	-	(9.5)	-	-	-	(0.1)	-	(0.1)
Excess tax benefit from stock-based awards	1.3	-	1.3	-	-	-	-	-	-
Contributions (distributions) (10)	-	1.0	(1.0)	-	13.2	(13.2)	-	(95.7)	95.7
Partnership equity transactions (11)	-	-	-	-	-	-	317.8	317.8	-
Distributions under common control	-	-	-	-	-	-	-	(68.1)	68.1
Stock options exercised	-	-	-	-	-	-	0.9	-	0.9
Dividends to preferred shareholders	-	-	-	-	-	-	(238.0)	-	(238.0)
Net cash provided by (used in) financing activities	1,093.0	1,140.8	(47.8)	87.4	84.5	2.9	(137.9)	(250.9)	113.0
Net change in cash and cash equivalents	(69.5)	12.4	(81.9)	(42.6)	(20.7)	(21.9)	(64.0)	(14.6)	(49.4)
Cash and cash equivalents, beginning of period	145.8	55.6	90.2	188.4	76.3	112.1	252.4	90.9	161.5
Cash and cash equivalents, end of period	$76.3	$68.0	$8.3	$145.8	$55.6	$90.2	$188.4	$76.3	$112.1

The major Non-Partnership cash flow items relate to:

(1) Affiliated indebtedness that was settled in drop down transactions.

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

(3) Reflects the Partnership's state margin tax, and TRC's federal and state taxes.

(4) Pursuant to the Purchase and Sale Agreement of the Downstream Business acquisition, we were entitled to receive GCF distributions of $2.3 in 2010.

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

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

(7) Cash activity related to TRC and TRI debt obligations.

(8) TRP cash distributions, including distributions received by TRC from the Partnership for its general partner interest, limited partner interest, IDRs, and net cash distributions related to noncontrolling interests.

(9) Reflects the repurchase of TRC common stocks from employees to satisfy the employees' minimum statutory tax withholdings on the vested awards.

(10) Contributions (distributions) to affiliates.

(11) Reflects TRP equity offerings, inclusive of TRC purchase of limited partner units and TRC's additional equity contribution to maintain its 2% general partner interest.

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Consolidated Results of Operations

The following table and discussion is a summary of our consolidated results of operations for the years ended December 31, 2012, 2011 and 2010 (in millions, except operating statistics and price amounts):

	2012	2011	2010	2012 vs. 2011		2011 vs. 2010	
Revenues	$5,885.7	$6,994.5	$5,476.1	$(1,108.8)	(16%)	$1,518.4	28%
Product purchases	4,879.0	6,039.0	4,695.5	(1,160.0)	(19%)	1,343.5	29%
Gross margin (1)	1,006.7	955.5	780.6	51.2	5%	174.9	22%
Operating expenses	313.1	287.1	259.3	26.0	9%	27.8	11%
Operating margin (2)	693.6	668.4	521.3	25.2	4%	147.1	28%
Depreciation and amortization expenses	197.6	181.0	185.5	16.6	9%	(4.5)	(2%)
General and administrative expenses	139.8	136.1	144.4	3.7	3%	(8.3)	(6%)
Other operating (income) expense	19.9	0.2	(4.7)	19.7	nm	4.9	(104%)
Income from operations	336.3	351.1	196.1	(14.8)	(4%)	155.0	79%
Interest expense, net	(120.8)	(111.7)	(110.9)	(9.1)	8%	(0.8)	1%
Equity earnings	1.9	8.8	5.4	(6.9)	(78%)	3.4	63%
Loss on debt redemption	(11.1)	-	(17.4)	(11.1)	0%	17.4	(100%)
Gain (loss) on early debt extinguishment, net	(1.7)	-	12.5	(1.7)	0%	(12.5)	(100%)
Loss on mark-to-market derivative instruments	-	(5.0)	(0.4)	5.0	(100%)	(4.6)	1,150%
Other income (expense)	(8.4)	(1.2)	0.5	(7.2)	600%	(1.7)	(340%)
Income tax expense	(36.9)	(26.6)	(22.5)	(10.3)	39%	(4.1)	18%
Net income	159.3	215.4	63.3	(56.1)	(26%)	152.1	240%
Less: Net income attributable to noncontrolling interests	121.2	184.7	78.3	(63.5)	(34%)	106.4	136%
Net income (loss) attributable to Targa Resources Corp.	38.1	30.7	(15.0)	7.4	24%	45.7	(305%)

Less:							
Dividends on Series B preferred stock	-	-	(9.5)	-	0%	9.5	(100%)
Dividends to common equivalents	-	-	(177.8)	-	0%	177.8	(100%)
Net income (loss) available to common shareholders	$38.1	$30.7	$(202.3)	$7.4	24%	$233.0	(115%)
Operating statistics:							
Plant natural gas inlet, MMcf/d (3) (4)	2,098.3	2,162.1	2,268.0	(63.8)	(3%)	(63.8)	(3%)
Gross NGL production, MBbl/d	128.7	123.9	121.2	4.8	4%	4.8	4%
Natural gas sales, BBtu/d (4)	927.6	779.3	685.8	148.3	19%	148.1	22%
NGL sales, MBbl/d	284.5	269.6	251.5	14.9	6%	14.8	6%
Condensate sales, MBbl/d	3.5	3.0	3.5	0.5	17%	0.3	10%

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

(3) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.

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

2012 Compared to 2011

Revenues, including the impacts of hedging, decreased due to the impact of lower realized prices on commodities ($1,965.3 million), partially offset by higher commodity sales volumes ($769.7 million) and higher fee-based and other revenues ($86.8 million).

The increase in gross margin reflects lower revenues more than offset by lower product purchases. For additional information regarding the period to period changes in our gross margins see "– Results of Operations – By Reportable Segment."

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.

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

Other operating (income) expense reflects a $15.4 million loss due to a write-off of the Partnership's 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 includes $3.6 million in costs associated with the clean-up and repairs necessitated by Hurricane Isaac at the Partnership's Coastal Straddle plants.

The increase in interest expense was the result of higher borrowings ($22.3 million), offset by a lower effective interest rate ($3.0 million) and higher capitalized interest ($10.2 million) attributable to major expansion capital projects.

Operations at the Partnership's non-operated equity investment, GCF, were impacted by the planned shutdown of operations that started during the second quarter and completed in the third quarter of 2012. The planned shutdown was associated with GCF's 43 MBbl/d capacity expansion. The facility's operations were also hampered by start-up issues associated with the expansion. This resulted in lower equity earnings from this equity investment for 2012 compared to 2011.

Losses on a debt redemption and early debt extinguishments during 2012 are largely attributable to premiums and write-offs of debt issue costs in connection with the redemption of the Partnership's 8¼% Notes due 2016 (the "8¼% Notes") and the amendment of the revolving credit facilities. 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 during the second quarter of that year. Consequently, the Partnership discontinued hedge accounting on those swaps, and changes in fair value and cash settlements were recorded as mark-to-market loss. The Partnership terminated all of its interest rate swaps in 2011 and therefore no comparable loss was recognized in 2012.

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

The decrease in earnings attributable to noncontrolling interests is primarily due to lower Partnership earnings and increased incentive distributions. After adjusting for the impact of the IDRs, the weighted average percentages of the net income allocable to noncontrolling interest decreased from 70.2% in 2011 to 53.0% in 2012. Additionally, net income attributable to noncontrolling interests was $12.4 million lower due to increased net income of CBF more than offset by decreased net income of Versado and VESCO, primarily due to a weaker price environment.

2011 Compared to 2010

Revenues (including the impacts of hedging) increased due to the net impact of higher realized prices on NGLs and condensate ($1,077.2 million), higher natural gas and NGL sales volumes ($488.4 million) and higher fee-based and other revenues ($80.7 million), partially offset by lower natural gas prices ($116.8 million) and lower condensate sales volumes ($11.1 million).

The increase in gross margin reflects higher revenues partially offset by higher product purchases. For additional information regarding the period to period changes in our gross margins see "– Results of Operations – By Reportable Segment."

The increase in operating expenses primarily reflects increased compensation and benefits expenses ($7.4 million), and increased maintenance and fuel costs, utilities and catalyst costs ($16.0 million). See "– Results of Operations – By Segment" for additional discussion regarding changes in operating expenses.

The decrease in depreciation and amortization expenses of $4.5 million was driven by an impairment charge in 2010 ($10.8 million) related to idled terminal and processing assets, plus assets that became fully depreciated in 2010 ($2.2 million). Factors that partially offset this decrease were: (1) depreciation on assets and expansions that were placed in service during 2010 and had a full year of expense in 2011 ($4.1 million); (2) the impact of Petroleum Logistics acquisitions in 2011 ($2.0 million); and (3) expansion projects that went online during 2011 ($4.4 million).

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General and administrative expenses decreased $8.3 million, primarily due to lower professional service fees in 2011, as compared to 2010, when we incurred professional fees associated with our IPO and drop-down transactions.

Interest expense was essentially flat as higher interest expense ($26.3 million) from an increase in third-party debt obligations of the Partnership was offset by lower interest expense ($25.5 million) from a reduction in our outstanding borrowings.

The increase in loss on mark-to-market derivative instruments ($4.6 million) is attributable to a portion of interest rate swaps that no longer qualified for hedge accounting treatment as of February 11, 2011.

At December 31, 2011 our ownership in the Partnership was 16.5% versus 17.1% at year-end 2010. After adjusting for the impact of the incentive distribution rights, our weighted average percentages of the net income of the Partnership were 29.8% in 2011 and 35.5% in 2010. The dilution of our earnings of the Partnership is a result of our sale of common units in April 2010 (6%). This impact was partially offset by issuance of common units to us associated with the assets dropped down to the Partnership, which were also offset by an increasing share of earnings from our ownership of the IDR’s (1%) due to increased distributions from the Partnership. Additionally, $16.1 million of the increase was due to increased net income subject to noncontrolling interest for CBF, Versado and VESCO.

Results of Operations—By Reportable Segment

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

	Partnership Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	TRC Non-Partnership	Consolidated Operating Margin
				(In millions)			
2012	$231.2	$115.1	$188.3	$116.0	$41.1	$1.9	$693.6
2011	287.9	174.3	123.1	113.4	(37.6)	7.3	668.4
2010	236.6	107.8	83.8	80.5	4.0	8.6	521.3

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Results of Operations of the Partnership – By Reportable Segment

Gathering and Processing Segments

Field Gathering and Processing

	2012	2011	2010	2012 vs. 2011		2011 vs. 2010	
				($ in millions)			
Gross margin	$357.4	$403.6	$338.8	$(46.2)	(11%)	$64.8	19%
Operating expenses	126.2	115.7	102.2	10.5	9%	13.5	13%
Operating margin	$231.2	$287.9	$236.6	$(56.7)	(20%)	$51.3	22%
Operating statistics (1):							
Plant natural gas inlet, MMcf/d (2),(3)							
Sand Hills	145.2	134.2	128.7	11.0	8%	5.5	4%
SAOU	124.8	111.0	99.8	13.8	12%	11.2	11%
North Texas System	244.5	203.5	180.4	41.0	20%	23.1	13%
Versado	167.4	162.8	178.8	4.6	3%	(16.0)	(9%)
	681.9	611.5	587.7	70.4	12%	23.8	4%
Gross NGL production, MBbl/d							
Sand Hills	16.9	15.7	14.8	1.2	8%	0.9	6%
SAOU	19.2	17.4	15.3	1.8	10%	2.1	14%
North Texas System	26.8	22.9	20.7	3.9	17%	2.2	11%
Versado	19.7	18.2	20.4	1.5	8%	(2.2)	(11%)
	82.6	74.2	71.2	8.4	11%	3.0	4%
Natural gas sales, BBtu/d (3)	325.0	285.5	258.6	39.5	14%	26.9	10%
NGL sales, MBbl/d	68.5	59.8	56.6	8.7	15%	3.2	6%
Condensate sales, MBbl/d	3.2	2.8	2.9	0.4	14%	(0.1)	(3%)
Average realized prices (4):							
Natural gas, $/MMBtu	2.60	3.80	4.09	(1.20)	(32%)	(0.29)	(7%)
NGL, $/gal	0.87	1.23	0.93	(0.36)	(29%)	0.30	32%
Condensate, $/Bbl	88.49	91.55	75.48	(3.06)	(3%)	16.07	21%

(1)

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

(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 include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.

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

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.

2011 Compared to 2010

The increase in gross margin for 2011 was primarily due to higher NGL and condensate sales prices, higher natural gas and NGL volumes and higher fee-based and other revenues, partially offset by higher product purchases, lower natural gas sales prices and lower condensate sales volumes. The increase in plant inlet volumes was largely attributable to new well connects, particularly at North Texas and SAOU. These factors were partially offset by the impact of severe cold weather, operational outages in 2011 and production declines at our Versado system. Natural gas sales increased due to higher throughput and a decrease in take-in-kind volumes.

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The increase in operating expenses was primarily due to higher fuel, utilities and catalysts expenses, higher system maintenance expenses driven by severe cold weather and operational outages in 2011, higher compensation and benefit costs and higher contract and professional service expenses.

Coastal Gathering and Processing

	2012	2011	2010	2012 vs. 2011		2011 vs. 2010	
				($ in millions)			
Gross margin	$162.2	$221.6	$151.2	$(59.4)	(27%)	$70.4	47%
Operating expenses (1)	47.1	47.3	43.4	(0.2)	(%)	3.9	9%
Operating margin	$115.1	$174.3	$107.8	$(59.2)	(34%)	$66.5	62%
Operating statistics (2):							
Plant natural gas inlet, MMcf/d (3),(4)							
LOU (5)	260.6	175.7	184.6	84.9	48%	(8.9)	(5%)
Coastal Straddles	676.2	876.4	1,068.4	(200.2)	(23%)	(192.0)	(18%)
VESCO	479.6	498.5	427.3	(18.9)	(4%)	71.2	17%
	1,416.4	1,550.6	1,680.3	(134.2)	(9%)	(129.7)	(8%)
Gross NGL production, MBbl/d							
LOU	8.6	7.4	7.2	1.2	16%	0.2	3%
Coastal Straddles	15.4	16.5	19.7	(1.1)	(7%)	(3.2)	(16%)
VESCO	22.1	25.9	23.2	(3.8)	(15%)	2.7	12%
	46.1	49.8	50.1	(3.7)	(7%)	(0.3)	(1%)
Natural gas sales, BBtu/d (4)	298.5	268.4	294.2	30.1	11%	(25.8)	(9%)
NGL sales, MBbl/d	42.5	43.5	43.7	(1.0)	(2%)	(0.2)	(%)
Condensate sales, MBbl/d	0.3	0.3	0.5	-	-	(0.2)	(40%)
Average realized prices:							
Natural gas, $/MMBtu	2.78	4.02	4.48	(1.24)	(31%)	(0.46)	(10%)
NGL, $/gal	0.96	1.31	1.03	(0.35)	(27%)	0.28	27%
Condensate, $/Bbl	103.57	105.10	78.82	(1.53)	(1%)	26.28	33%

(1) Costs associated with the clean-up and repair of Coastal Straddle plants resulting from Hurricane Isaac are reported as Other Operating Expenses and thus are not reflected in operating margin.

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

(3) Plant natural gas inlet represents the volume of natural gas passing through the meter located at the inlet of a natural gas processing plant.
(4) Plant natural gas inlet volumes include producer take-in-kind volumes, while natural gas sales exclude producer take-in-kind volumes.
(5) Includes volumes from the Big Lake processing plant acquired in July 2012.

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 and increased sales to other reportable segments for resale.

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.

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2011 Compared to 2010

The increase in gross margin is primarily attributable to higher NGL and condensate sales prices, favorable frac spread as a result of low gas prices relative to NGLs and crude oil, a significant increase in higher GPM keep-whole volumes at VESCO and the Lowry processing facility and higher system average GPM at LOU, largely due to increased traditional wellhead volumes. The decrease in plant inlet volumes was largely attributable to a decline in other offshore and off-system supply volumes. Despite the lower inlet volumes, NGL production and sales volumes remained relatively flat as a result of the above-mentioned higher GPM gas and the optimization of throughput to more efficient, higher recovery plants. Natural gas sales volumes decreased due to lower demand from industrial customers and lower sales to other reportable segments for resale.

The increase in operating expenses was primarily due to higher contract and professional service expenses, higher miscellaneous and other expenses, higher operating expenses on non-operated joint ventures and a decrease in recovery of expenses by an operated joint venture.

Logistics and Marketing Segments

Logistics Assets

	2012	2011	2010	2012 vs. 2011		2011 vs. 2010	
			($ in millions)				
Gross margin	$286.0	$221.1	$171.4	$64.9	29%	$49.7	29%
Operating expenses	97.7	98.0	87.6	(0.3)	(%)	10.4	12%
Operating margin	$188.3	$123.1	$83.8	$65.2	53%	$39.3	47%
Operating statistics (1):							
Fractionation volumes, MBbl/d	299.2	268.4	230.8	30.8	11%	37.6	16%
Treating volumes, MBbl/d (2)	22.4	15.3	18.0	7.1	46%	(2.7)	(15%)

(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 quarter and the denominator is the number of calendar days during the quarter.
(2) Includes the volumes related to the natural gasoline hydrotreater at the Mt. Belvieu facility.

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. Exporting 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 Cedar Bayou facility 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.

2011 Compared to 2010

The increase in gross margin was primarily due to higher fractionation and treating revenue, higher terminaling and storage revenue and higher fee-based and other revenue. Higher fractionation revenues were driven by the expansion at CBF. LSNG customers, contractually bound to take-or-pay contracts for treating services, decided not to use their reserved throughput in the fourth quarter of 2011, leading to lower treating volumes compared to 2010. The increase in terminaling and storage revenue was partially due to the impact of propane and normal butane exports. The increase in fee-based and other revenue is due to the 2011 acquisitions of petroleum terminaling assets.

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The increase in operating expenses was primarily due to higher utilities, power and catalyst costs as a result of the expansion of the CBF facility, higher compensation and benefits expense, system maintenance costs, and contract and professional services fees, partially offset by an increase in system product gains as a result of increased volumes at the expanded CBF, which provides more favorable product upgrades. Higher operating expenses also reflect the 2011 acquisitions of petroleum terminaling assets.

Marketing and Distribution

	2012	2011	2010	2012 vs. 2011		2011 vs. 2010	
				($ in millions)			
Gross margin	$154.1	$156.4	$125.3	$(2.3)	(1%)	$31.1	25%
Operating expenses	38.1	43.0	44.8	(4.9)	(11%)	(1.8)	(4%)
Operating margin	$116.0	$113.4	$80.5	$2.6	2%	$32.9	41%
Operating statistics (1):							
Natural gas sales, BBtu/d	1,105.0	877.8	634.9	227.2	26%	242.9	38%
NGL sales, MBbl/d	289.8	272.5	246.7	17.3	6%	25.8	10%
Average realized prices:							
Natural gas, $/MMBtu	2.74	3.94	4.31	(1.20)	(30%)	(0.37)	(9%)
NGL realized price, $/gal	0.98	1.34	1.10	(0.36)	(27%)	0.24	22%

(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 quarter and the denominator is the number of calendar days during the quarter.

2012 Compared to 2011

The decrease in gross margin was 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 in 2012 compared to 2011, partially offset by increased truck operating costs.

2011 Compared to 2010

The increase in gross margin was primarily due to higher NGL sales prices, higher natural gas and NGL sales volumes and increased fee-based and other revenues, partially offset by increased product purchases, lower natural gas sales prices and lower condensate sales volumes. NGL sales volumes rose on increased demand from industrial customers and from increased export sales. Natural gas sales volumes increased due to higher natural gas purchases which resulted in incremental increases in volumes processed by other reportable segments.

Operating expenses decreased due to lower railcar expenses and contractor and professional services fees, partially offset by higher system maintenance costs and compensation and benefits expenses.

Other

	2012	2011	2010	2012 vs. 2011	2011 vs. 2010
			(In millions)		
Gross margin	$41.1	$(37.6)	$4.0	$78.7	$(41.6)
Operating margin	$41.1	$(37.6)	$4.0	$78.7	$(41.6)

Other contains the financial effects of the Partnership's hedging program on operating margin. It typically represents the cash settlements on the Partnership's 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 the Partnership's commodity risk management activities is to manage its exposure to commodity price risk and reduce volatility in its operating cash flow due to fluctuations in commodity prices. The Partnership has hedged the commodity price associated with a portion of its expected (i) natural gas equity volumes in Field Gathering and Processing Operations and (ii) NGL and condensate equity volumes predominately in Field Gathering and Processing as well as in the LOU portion of the Coastal Gathering and Processing Operations that result from its percent of proceeds processing arrangements by entering into derivative instruments. Because the Partnership is essentially forward selling a portion of its plant equity volumes, these hedge positions will move favorably in periods of falling prices and unfavorably in periods of rising prices.

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The following table provides a breakdown of the Partnership's hedge revenue by product:

	2012	2011	2010	2012 vs. 2011	2011 vs. 2010
			(In millions)		
Natural gas	$33.8	$21.2	$20.2	$12.6	$1.0
NGL	9.1	(53.1)	(14.2)	62.2	(38.9)
Crude oil	(1.8)	(5.7)	(2.0)	3.9	(3.7)
	$41.1	$(37.6)	$4.0	$78.7	$(41.6)

The increase in gross margin from risk management activities between 2012 and 2011 was primarily due to decreasing natural gas, NGL and crude oil prices.

The decrease in gross margin from risk management activities between 2011 and 2010 was primarily due to increasing NGL and crude oil prices, partially offset by decreasing prices of natural gas.

Our Liquidity and Capital Resources

We have no separate, direct operating activities apart from those conducted by the Partnership. As such, our ability to finance our operations, including payment of dividends to our common stockholders, funding capital expenditures and acquisitions, or to meet our indebtedness obligations, will depend on cash inflows from future cash distributions to us from our interests in the Partnership. The Partnership is required to distribute all available cash at the end of each quarter after establishing reserves to provide for the proper conduct of its business or to provide for future distributions. See "Item 1A. Risk Factors." As of February 15, 2013, our interests in the Partnership consist of the following:

- a 2% general partner interest, which we hold through our 100% ownership interest in the general partner of the Partnership;
- all of the outstanding IDRs; and
- 12,945,659 of the 101,788,617 outstanding common units of the Partnership, representing a 12.7% limited partnership interest.

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

Our future cash flows will consist of distributions to us from our interests in the Partnership, from which we intend to make quarterly cash dividends to our stockholders from available cash. Based on our anticipated levels of distributions that we expect to receive from the Partnership, cash generated from this interest should provide sufficient resources to finance our operations, long-term debt and quarterly cash dividends for at least the next twelve months.

The impact on us of changes in the Partnership's distribution levels will vary depending on several factors, including the Partnership's total outstanding partnership interests on the record date for the distribution, the aggregate cash distributions made by the Partnership and the interests in the Partnership owned by us. If the Partnership increases distributions to its unitholders, including us, we would expect to increase dividends to our stockholders, although the timing and amount of such increased dividends, if any, will not necessarily be comparable to the timing and amount of the increase in distributions made by the Partnership. In addition, the level of distributions we receive and of dividends we pay to our stockholders may be affected by the various risks associated with an investment in us and the underlying business of the Partnership. Please read "Item 1A. Risk Factors" for more information about the risks that may impact your investment in us.

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As of February 1, 2013, our liquidity consisted of the following:

	February 1, 2013
	(In millions)
Cash on hand	$ 10.8
Total availability under TRC's credit facility	150.0
Less: Outstanding borrowings under TRC's credit facility	(87.0)
Less: Outstanding letters of credit outstanding under TRC's credit facility	-
Total liquidity	$ 73.8

Subsequent Event

On January 15, 2013, the Partnership announced that the board of directors of its general partner declared a quarterly distribution for the three months ended December 31, 2012 of $0.68 per common unit, or an annual rate of $2.72 per common unit. This distribution was paid on February 14, 2013. Based on these current distribution rates, we will receive approximate distributions in future quarters and years of:

- $8.8 million or $35.2 million annually based on our common unit ownership in the Partnership;
- $20.1 million or $80.3 million annually based on our IDRs; and
- $1.8 million or $7.3 million annually based on our 2% general partner interests.

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

The following table details the dividends declared and/or paid since our initial public offering on December 10, 2010 through December 31, 2012:

Three Months Ended	Date Paid	Total Dividend Declared	Amount of Dividend Paid	Accrued Dividends (1)	Dividend Declared per Share of Common Stock
	(In millions, except per share amounts)				
2012					
December 31, 2012	February 15, 2013	$ 19.4	$ 19.0	$ 0.4	$ 0.45750
September 30, 2012	November 15, 2012	18.0	17.3	0.7	0.42250
June 30, 2012	August 15, 2012	16.7	16.1	0.6	0.39375
March 31, 2012	May 16, 2012	15.5	15.0	0.5	0.36500

2011						
December 31, 2011	February 15, 2012	$ 14.3	$ 13.8	$ 0.5	$ 0.33625	
September 30, 2011	November 15, 2011	13.0	12.6	0.4	0.30750	
June 30, 2011	August 16, 2011	12.3	11.9	0.4	0.29000	
March 31, 2011	May 13, 2011	11.6	11.2	0.4	0.27250	
2010						
December 31, 2010	February 14, 2011	$ 2.6	$ 2.5	$ 0.1	$ 0.06160	(2)

(1) Represents accrued dividends on the restricted shares that are payable upon vesting.

(2) Represents a prorated dividend for the portion of the fourth quarter of 2010 that the Company was public.

We have sufficient liquidity to satisfy a $70.6 million tax liability over the next 12 years related to our sales of assets to the Partnership.

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The Partnership's Liquidity and Capital Resources

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

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

As of February 1, 2013, the Partnership's liquidity consisted of the following:

	February 1, 2013
	(In millions)
Cash on hand	$ 124.5
Total availability under the TRP Revolver	1,200.0
Less: Outstanding borrowings under the TRP Revolver	(480.0)
Less: Outstanding letters of credit outstanding under the TRP Revolver	(45.7)
Total liquidity	$ 798.8

The Partnership may issue additional equity or debt securities to assist it in meeting future liquidity and capital spending requirements. The Partnership filed with the SEC a universal shelf registration statement (the "2010 Shelf"), which provides it with the ability to offer and sell an unlimited amount of debt and equity securities, subject to market conditions and the Partnership's capital needs. Over the last two years, the Partnership conducted four equity offerings under the 2010 Shelf with proceeds totaling $1,019.3 million. The 2010 Shelf expires in April 2013.

The Partnership also filed with the SEC a universal shelf registration statement that allows the Partnership to issue up to an aggregate of $300 million of debt or equity securities (the "2012 Shelf"). In August 2012, the Partnership entered into an Equity Distribution Agreement ("EDA") with Citigroup Global Markets Inc. ("Citigroup") pursuant to which the Partnership 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. Settlement for sales of common units will occur on the third business day following the date on which any sales were made in return for payment of the net proceeds to the Partnership. As of December 31, 2012, there were no sales of common units pursuant to this program. However, during the first quarter of 2013, the Partnership sold securities under the program. See "Subsequent Events" below. The 2012 Shelf expires in August 2015.

Subsequent Events

In 2013, the Partnership issued 1,679,848 common units and received proceeds of $64.1 million, net of 2% commission fees, pursuant to the EDA. In addition, we contributed $1.3 million to maintain our 2% general partner interest.

In January 2013, the Partnership entered into its Securitization Facility that provides up to $200 million of borrowing capacity at favorable commercial paper rates through January 2014. Under this Securitization Facility, one of the Partnership's consolidated subsidiaries (Targa Liquids Marketing and Trade LLC or "TLMT") sells or contributes receivables to another of the Partnership's 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, without recourse, 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 us or TLMT. Any excess receivables are eligible to satisfy the claims of creditors of us or TLMT. Total funding under this Securitization Facility in January 2013 was $171.4 million.

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Risk Management

The Partnership evaluates counterparty risks related to its commodity derivative contracts and trade credit. The Partnership has all of its commodity derivatives with major financial institutions or major oil companies. Should any of these financial counterparties not perform, the Partnership may not realize the benefit of some of its hedges under lower commodity prices, which could have a material adverse effect on its results of operation. The Partnership sells its 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 the Partnership's cash flows, the Partnership has hedged the commodity price associated with a portion of its expected natural gas equity volumes through 2015 and its NGL and condensate equity volumes through 2014 by entering into derivative instruments including swaps and purchased puts (or floors). With these arrangements, the Partnership has attempted to mitigate its exposure to commodity price movements with respect to its forecasted volumes for this period. See "Quantitative and Qualitative Disclosures About Market Risk—Commodity Price Risk." The current market conditions may also impact the Partnership's ability to enter into future commodity derivative contracts.

The Partnership's risk management position has moved from a net liability position of $5.0 million at December 31, 2011 to a net asset position of $22.2 million at December 31, 2012. Aggregate forward prices for commodities are below the fixed prices the Partnership currently expects to receive on those derivative contracts, creating a net asset position. Consequently, the Partnership's expected future receipts on derivative contracts are greater than its expected future payments. The Partnership accounts for derivatives that mitigate commodity price risk as cash flow hedges. Changes in fair value are deferred in OCI until the underlying hedged transactions settle.

Working Capital

Working capital is the amount by which current assets exceed current liabilities. On a consolidated basis at the end of any given month, accounts receivable and payable tied to commodity sales and purchases are relatively balanced with receivables from NGL customers offset by plant settlements payable to producers. The factors that typically cause overall variability in the Partnership's reported total working capital are: (1) the Partnership's cash position; (2) liquids inventory levels and their valuation, which the Partnership closely manages; and (3) changes in the fair value of the current portion of derivative contracts.

For 2012, the Partnership's working capital decreased by $12.1 million primarily due to an increase in non-commodity accounts payable and accrued liabilities of $90.5 million and an increase in accounts payable, net of receivables, for commodities of $32.8 million, partially offset by increases in the net current portion of derivative contracts of $22.0 million, cash of $12.4 million, inventory of $7.3 million and non-commodity receivables of $4.7 million. The impact of the Badlands acquisition was an increase in working capital of $16.2 million, primarily acquired inventory.

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

A significant portion of the Partnership's capital resources may be utilized in the form of letters of credit to satisfy certain counterparty credit requirements. While the Partnership's credit rating has improved over the last year, these letters of credit reflect its non-investment grade status, as assigned to us by Moody's Investors Service, Inc. and Standard & Poor's Corporation, and counterparties' views of the Partnership's financial condition and ability to satisfy its performance obligations, as well as commodity prices and other factors. As of December 31, 2012, the Partnership had $45.3 million in letters of credit outstanding.

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Cash Flow

The following table and discussion summarize our consolidated cash flows provided by or used in operating activities, investing activities and financing activities for the periods indicated. See "Statement of Cash Flows – Partnership versus Non-Partnership" for a detailed presentation of cash flow activity:

2012	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
Net cash provided by (used in):		(In millions)	
Operating activities	$428.2	$465.4	$ (37.2)
Investing activities	(1,590.7)	(1,593.8)	3.1
Financing activities	1,093.0	1,140.8	(47.8)
2011			
Net cash provided by (used in):			
Operating activities	$379.3	$400.9	$ (21.6)
Investing activities	(509.3)	(506.1)	(3.2)
Financing activities	87.4	84.5	2.9
2010			
Net cash provided by (used in):			
Operating activities	$205.2	$367.9	$ (162.7)
Investing activities	(131.3)	(131.6)	0.3
Financing activities	(137.9)	(250.9)	113.0

Cash Flow from Operating Activities - Partnership

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

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

	2012	2011	2010	2012 vs. 2011	2011 vs. 2010
			(In millions)		
Cash flows from operating activities:					
Cash received from customers	$5,948.9	$6,916.0	$5,400.1	$(967.1)	$1,515.9
Cash received from (paid to) derivative counterparties	47.3	(56.6)	38.1	103.9	(94.7)
Cash outlays for:					
Product purchases	(4,972.9)	(5,960.1)	(4,643.7)	987.2	(1,316.4)
Operating expenses	(339.6)	(286.1)	(274.6)	(53.5)	(11.5)
General and administrative expenses	(117.8)	(124.1)	(85.8)	6.3	(38.3)

Cash distributions from equity investment	1.8	8.3	5.4	(6.5)	2.9
Interest paid, net of amounts capitalized (1)	(92.5)	(92.7)	(68.7)	0.2	(24.0)
Income taxes paid	(2.2)	(2.5)	(3.1)	0.3	0.6
Other cash receipts (payments)	(7.6)	(1.3)	0.2	(6.3)	(1.5)
Net cash provided by operating activities	$465.4	$400.9	$367.9	$64.5	$33.0

(1) Net of capitalized interest paid of $13.6 million, $3.4 million and $1.3 million included in investing activities for 2012, 2011 and 2010.

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, the Partnership's derivative settlements were a net cash inflow, as opposed to a net outflow for 2011. The change in cash related to derivative counterparties reflects lower aggregate commodity prices compared to the higher aggregate fixed prices we receive 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.

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Higher aggregate commodity prices were the primary factor in the changes in cash from customers, cash from derivative contracts, cash paid for purchases in 2011 compared to 2010. In 2011, the Partnership's derivative settlements were a net cash outflow, as opposed to a net inflow in 2010. The change in cash paid to derivative counterparties reflects higher aggregate commodity prices compared to the lower aggregate fixed prices we receive on those derivative contracts, a payment for interest rate swaps terminated in the amount of $23.0 million, and total payments for ethane call options in the amount of $1.5 million.

Cash Flow from Operating Activities - Non-Partnership

The operating activities of TRC – Non-Partnership are primarily related to interest, taxes, retained general and administrative expenses and business interruption insurance proceeds.

Cash Flow from Investing Activities - Partnership

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.

Net cash used in investing activities increased by $374.5 million for 2011 compared to 2010. The increase was primarily due to the Partnership's petroleum logistics acquisitions of $156.5 million and a $157.0 million increase in expansion capital projects in gathering and processing assets and in fractionation capacity. The Partnership also invested $21.2 million in equity contributions associated with the expansion of fractionation capacity at GCF.

Cash Flow from Investing Activities – Non-Partnership

The increase in net cash provided by investing activities for 2012 compared to 2011 was primarily due to a transfer of corporate administrative assets from us to the Partnership and a decrease in capital expenditures.

During 2011, Non-Partnership net cash used in investing activities consisted of $3.2 million in outlays for corporate administrative assets. During 2010, net cash provided by investing activities primarily consisted of $3.5 million in insurance recoveries, partially offset by outlays for corporate administrative assets of $2.3 million.

Cash Flow from Financing Activities - Partnership

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 the issuance of common units of the Partnership of $250.4 million, partially offset by an increase in distributions to owners of $47.1 million.

The Partnership's primary financing activities that occurred during 2012 were:

- In January 2012, the Partnership completed an offering of 4,405,000 common units (including underwriters' overallotment option) at a price of $38.30 per common unit, providing net proceeds of $164.9 million. As part of this offering, we purchased 1,300,000 common units with an aggregate value of $49.8 million. We contributed $3.4 million to maintain our 2% general partner interest. See Note 11 of the "Consolidated Financial Statements."

- In January 2012, the Partnership privately placed $400.0 million of 6 % Senior Notes due 2022 (the "6 % Notes"). See Note 10 of the "Consolidated Financial Statements."

- In October 2012, the Partnership privately placed $400.0 million of 5¼% Senior Notes due 2023 (the "5¼% Notes"), See Note 10 of the "Consolidated Financial Statements."

- In November 2012, the Partnership completed a public offering of 9,500,000 common units at a price of $36.00 per common unit ($34.65 per common unit, net of underwriting discounts). Net proceeds from this offering were approximately $329.2 million. Pursuant to the exercise of the underwriters' overallotment option, the Partnership issued an additional 1,425,000 common units, providing net proceeds of approximately $49.4 million. In addition, we contributed $8.0 million to the Partnership for 222,959 general partner units to maintain our 2% general partner interest in the Partnership. See Note 11 of the "Consolidated Financial Statements."

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- In December 2012, the Partnership privately placed an additional $200.0 million of the 5¼% Notes, See Note 10 of the "Consolidated Financial Statements."

Net cash from the completion of the January equity and debt offerings was used to reduce outstanding borrowings under the TRP Revolver. Net cash from the issuance of the 5¼% Notes in October was used to redeem all of the outstanding 8¼% Senior Notes and reduce borrowings under the TRP Revolver. Net cash from the November unit offering was used to partially fund the Badlands acquisition. Net cash from the issuance of the 5¼% Notes in December was used to partially fund the Badlands acquisition.

Net cash provided by financing activities for 2011 was $84.5 million compared to net cash used in financing activities of $250.9 million for 2010. The increase was due to two primary factors: changes in the Partnership's equity offerings and financing activities and distributions.

Net proceeds from public offerings, issuance of senior notes and borrowings under the TRP Revolver less repayments on the TRP Revolver increased $211.1 million from $123.0 million for 2010 to $334.1 million for 2011. The Partnership's primary financing activities during 2011 were:

- In January 2011, the Partnership completed a public offering of 8,000,000 common units at a price of $33.67 per common unit ($32.41 per common unit, net of underwriting discounts), providing net proceeds of $259.2 million. Pursuant to the exercise of the underwriters' overallotment option, on February 3, 2011 the Partnership issued an additional 1,200,000 common units, providing net proceeds of approximately $38.8 million. In addition, we contributed $6.3 million for 187,755 general partner units to maintain our 2% general partner interest.

- In February 2011, the Partnership closed a private placement of $325.0 million in aggregate principal amount of its 6 % Notes due 2012 (the "6 % Notes") resulting in net proceeds of $318.8 million.

- In February 2011, the Partnership exchanged an additional $158.6 million principal amount of its 6 % Notes for $158.6 million aggregate principal amount of the Partnership's 11¼% Notes. In conjunction with the exchange the Partnership paid a cash premium of $28.6 million including $0.9 million of accrued interest.

Net cash from the completion of the above offerings was used to reduce outstanding borrowings under the TRP Revolver by $553.4 million.

Cash Flow Financing Activities - Non-Partnership

The decrease in net cash provided by financing activities for 2012 compared to 2011 was primarily attributable to the purchase of 1,300,000 of the Partnership's common units in January 2012, purchase of general partner units of the Partnership, payment of dividends, purchase of treasury stock and net payments to reduce long-term debt, partially offset by an increase in distributions received from the Partnership.

Non-Partnership net cash provided by financing activities decreased by $110.0 million during 2011. During 2010, we received from the Partnership $737.7 million in repayments of affiliated indebtedness, and received $224.4 million from the sale of Partnership interests. These proceeds were primarily used to pay $448.1 million in dividends to common and common equivalent shareholders and preferred shareholders, and $592.4 million in outstanding balances on our loan facilities during 2010. Distributions to us from the Partnership increased $14.3 million in 2011 compared to 2010 primarily from a $15.7 million increase in distributions related to our incentive distribution rights, partially offset by a $2.5 million decrease in limited partner distributions due to our sale of Partnership interests during 2010.

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Distributions from the Partnership and Dividends of TRC

The following table details the distributions declared and/or paid by the Partnership during 2012, 2011 and 2010 with respect to our 2% general partner interest, the associated IDRs and common units that we held during the periods indicated along with dividends declared by us to our shareholders for the same periods:

For the Three Months Ended	Date Paid	Cash Distribution Per Limited Partner Unit	Cash Distributions Limited Partner Units	General Partner Interest	IDRs	Distributions to Targa Resources Corp. (1)	Dividend Declared Per TRC Common Share	Total Dividend Declared to Common Shareholders
			(In millions, except per unit amounts)					
2012								
December 31, 2012	February 14, 2013	$ 0.6800	$ 8.8	$ 1.8	$ 20.1	$ 30.7	$ 0.45750	$ 19.4
September 30, 2012	November 14, 2012	0.6625	8.6	1.5	16.1	26.2	0.42250	18.0
June 30, 2012	August 14, 2012	0.6425	8.3	1.5	14.4	24.2	0.39375	16.7
March 31, 2012	May 15, 2012	0.6225	8.1	1.4	12.7	22.2	0.36500	15.5
2011								
December 31, 2011	February 14, 2012	$ 0.6025	$ 7.8	$ 1.3	$ 11.0	$ 20.1	$ 0.33625	$ 14.3
September 30, 2011	November 14, 2011	0.5825	6.8	1.2	8.8	16.8	0.30750	13.0
June 30, 2011	August 12, 2011	0.5700	6.6	1.2	7.8	15.6	0.29000	12.3
March 31, 2011	May 13, 2011	0.5575	6.5	1.1	6.8	14.4	0.27250	11.5
2010								
December 31, 2010	February 14, 2011	$ 0.5475	$ 6.4	$ 1.1	$ 6.0	$ 13.5	$ 0.06160	$ 2.6
September 30, 2010	November 12, 2010	0.5375	6.3	0.9	4.6	11.8	N/A	N/A
June 30, 2010	August 13, 2010	0.5275	6.1	0.8	3.5	10.4	N/A	N/A
March 31, 2010	May 14, 2010	0.5175	6.0	0.8	2.8	9.6	N/A	N/A

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

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 gas supply and service capability of our existing assets, including the replacement of system components and equipment which is worn, obsolete or completing its useful life, and expenditures to remain in compliance with environmental laws and regulations.

	2012			2011			2010		
	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC - Non-Partnership
	(In millions)								
Capital expenditures and business acquisitions:									
Business acquisitions, net of cash acquired (1)	$996.2	$ 996.2	$ -	$156.5	$ 156.5	$ -	$-	$ -	$ -
Expansion (2)	540.7	540.7	-	252.3	251.7	0.6	95.3	94.7	0.6
Maintenance	76.3	76.0	0.3	83.4	81.8	1.6	53.3	50.5	2.8
Gross additions to property, plant and equipment	1,613.2	1,612.9	0.3	492.2	490.0	2.2	148.6	145.2	3.4
Change in capital project payables and accruals	(34.3)	(34.4)	0.1	(3.8)	(4.8)	1.0	(9.3)	(8.2)	(1.1)
Cash outlays for capital projects and business acquisitions	$1,578.9	$ 1,578.5	$ 0.4	$488.4	$ 485.2	$ 3.2	$139.3	$ 137.0	$ 2.3

(1) Includes Badlands acquisition-related expenditures of $970.4 million, net of cash received.

(2) Excludes the Partnership's investment in GCF, which is accounted for as an equity investment. Cash calls for expansion are reflected in Investment in unconsolidated affiliate in cash flows from investing activities on our Consolidated Statement s of Cash Flows in our Consolidated Financial Statements

The Partnership estimates that its total growth capital expenditures for 2013 will be approximately $1.0 billion on a gross basis, and maintenance capital expenditures net to the Partnership's interest will be $75 million. Given the Partnership's objective of growth through acquisitions, expansions of existing assets and other internal growth projects, the Partnership anticipates that over time they will invest significant amounts of capital to grow and acquire assets.

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Major capital projects include:

- $480 million expansion of the Partnership's Mont Belvieu complex and the Partnership's existing import/export marine terminal at Galena Park to export international grade propane;
- $385 million expansion project at CBF to add a fourth fractionation train and related infrastructure enhancements at Mont Belvieu;
- $250 million in capital expansion programs to expand the gathering and processing capability of Badlands;
- $225 million High Plains project for a new cryogenic processing plant with associated expansion projects to expand the gathering and processing capability of SAOU;
- $150 million North Texas Longhorn project for a new cryogenic processing plant with associated expansion projects to expand the gathering and processing capability of the North Texas system;
- $50 million gathering and processing capital expansion program; and
- $50 million expansion of the Partnership's petroleum logistics assets.

These capital projects will extend through 2014. For a detailed discussion of these projects, see "Item 1. Business – Overview of the Partnership." Future expansion capital expenditures may vary significantly based on investment opportunities.

The Partnership expects to fund future capital expenditures with funds generated from its operations, borrowings under the TRP Revolver and proceeds from any issuances of additional common units and debt offerings.

Credit Facilities and Long-Term Debt

The following table summarizes consolidated debt obligations as of December 31, 2012 (in millions):

Non-Partnership Obligations:		
TRC Senior secured revolving credit facility due October 2017	$	82.0
Partnership Obligations		
Senior secured revolving credit facility, due October 2017		620.0
Senior unsecured notes, 11¼% fixed rate, due July 2017		72.7
Unamortized discount		(2.5)
Senior unsecured notes, 7 % fixed rate, due July 2018		250.0
Senior unsecured notes, 6 % fixed rate, due July 2021		483.6
Unamortized discount		(30.5)
Senior unsecured notes, 6 % fixed rate, due August 2022		400.0
Senior unsecured notes, 5¼% fixed rate, due May 2023		600.0

Total debt		2,475.3
Current maturities of debt		-
Total long-term debt	$	2,475.3

We consolidate the debt of the Partnership with that of our own; however, we do not have the contractual obligation to make interest or principal payments with respect to the debt of the Partnership. Our debt obligations do not restrict the ability of the Partnership to make distributions to us. TRC's Credit Agreement has restrictions and covenants that may limit our ability to pay dividends to our stockholders. Please read "—TRC Senior Secured Credit Agreement" for a discussion of the restrictions and covenants in TRC's Credit Agreement.

Compliance with Debt Covenants

As of December 31, 2012, both we and the Partnership were in compliance with the covenants contained in our various debt agreements.

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TRC Credit Agreement

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

In October 2012, using proceeds from our TRC Revolver and cash on hand; we paid $88.8 million to acquire the remaining $89.3 million of outstanding borrowings under the TRC Holdco Loan Facility.

The TRC Revolver bears interest, at our option, at either (a) a base rate equal to the highest of the prime rate of Deutsche Bank Trust Company Americas, the administrative agent, the federal funds rate plus 0.5% and the one-month LIBOR rate plus 1.0%, plus an applicable margin ranging from 1.75% to 2.5% (dependent upon the Company's consolidated leverage ratio), or (b) LIBOR plus an applicable margin ranging from 2.75% to 3.5% (dependent upon the Company's consolidated leverage ratio).

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

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

The Partnership's Revolving Credit Agreement

In October 2012, the Partnership entered into a Second Amended and Restated Credit Agreement that amends and replaces the Partnership's existing 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.

For 2012, the Partnership had gross borrowings under its TRP Revolver of $1,595.0 million, and repayments totaling $1,473.0 million, for a net increase for the year ended December 31, 2012 of $122.0 million. The TRP Revolver balance at December 31, 2012 was $620.0 million.

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

The Partnership is 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 from 1.75% to 2.75%.

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

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

The Partnership's Senior Unsecured Notes

In February 2011, the Partnership exchanged $158.6 million principal amount of its 6 % Notes plus payments of $28.6 million, including $0.9 million of accrued interest, for $158.6 million aggregate principal amount of its 11¼% Notes. The holders of the exchanged Notes are subject to the provisions of the 6 % 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, the Partnership privately placed $400.0 million in aggregate principal amount of its 6 % Notes, resulting in approximately $395.5 million of net proceeds.

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

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

The terms of the senior unsecured notes outstanding as of December 31, 2012 were as follows:

Note Issue	Issue Date	Per Annum Interest Rate	Due Date	Dates Interest Paid
"11¼% Notes"	July 2009	11¼%	July 15, 2017	January & July 15th
"7 % Notes"	August 2010	7 %	October 15, 2018	April & October 15th
"6 % Notes"	February 2011	6 %	February 1, 2021	January & July 1st
"6 % Notes"	January 2012	6 %	August 1, 2022	February & August 1st
"5¼% Notes"	Oct / Dec 2012	5¼%	May 1, 2023	May & November 1st

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 Partnership's credit facility. They are senior in right of payment to any of our future subordinated indebtedness and are unconditionally guaranteed by the Partnership. These notes are effectively subordinated to all secured indebtedness under the Partnership's credit agreement, which is secured by substantially all of the Partnership's assets and the Partnership's Securitization Facility, which is secured by accounts receivable pledged under the facility, to the extent of the value of the collateral securing that indebtedness. Interest on all issues of senior unsecured notes is payable semi-annually in arrears.

The Partnership's senior unsecured notes and associated indenture agreements (other than the indenture for the 11¼ Notes) restrict the Partnership's ability to make distributions to unitholders in the event of default (as defined in the indentures). The indentures also restrict the Partnership's ability and the ability of certain of its subsidiaries to: (i) incur additional debt or enter into sale and leaseback transactions; (ii) pay certain distributions on or repurchase, equity interests (only if such distributions do not meet specified conditions); (iii) make certain investments; (iv) incur liens; (v) enter into transactions with affiliates; (vi) merge or consolidate with another company; and (vii) transfer and sell assets. These covenants are subject to a number of important exceptions and qualifications. If at any time when the notes are rated investment grade by both Moody's Investors Service, Inc. and Standard & Poor's Ratings Services and no Default (as defined in the indentures) has occurred and is continuing, many of such covenants will terminate and the Partnership and its subsidiaries will cease to be subject to such covenants.

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Subsequent Events

In January 2013, the Partnership entered into a Securitization Facility that provides up to $200 million of borrowing capacity at favorable commercial paper rates through January 2014. Under this Securitization Facility, one of the Partnership's consolidated subsidiaries (TLMT) sells or contributes receivables to another of its 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, without recourse, 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 us or TLMT. Any excess receivables are eligible to satisfy the claims of creditors of us or TLMT. Total funding under this Securitization Facility in January 2013 was $171.4 million.

Off-Balance Sheet Arrangements

We currently have no off-balance sheet arrangements as defined by the Securities and Exchange Commission. See "Contractual Obligations" below and "Commitments and Contingencies" included under Note 17 to our "Consolidated Financial Statements" for a discussion of our commitments and contingencies.

Contractual Obligations

The following is a summary of contractual obligations over the next several fiscal years, representing amounts that were fixed and determinable as of December 31, 2012:

		Payments Due By Period			
Contractual Obligations	Total	Less Than 1 Year	1-3 Years (In millions)	3-5 Years	More Than 5 Years
Non-Partnership Obligations:					
Debt obligations (1)	$82.0	$-	$-	$82.0	$-
Interest on debt obligations (2)	12.8	2.7	5.4	4.7	-
Operating lease obligations (3)	1.2	0.3	0.6	0.3	-
Partnership Obligations:					
Debt obligations (1)	2,426.3	-	-	692.7	1,733.6
Interest on debt obligations (2)	1,114.2	135.8	279.9	261.7	436.8
Operating lease and service contract obligations (3)	37.1	6.5	11.6	9.3	9.7
Pipeline capacity and throughput agreements (4)	191.1	22.5	37.0	36.4	95.2
Land site lease and right-of-way (5)	7.3	1.6	2.9	2.8	-
Asset retirement obligation	45.3	-	-	-	45.3
Commodities (6)	216.5	216.5	-	-	-
Purchase commitments (7)	324.5	321.7	2.8	-	-
	$4,458.3	$707.6	$340.2	$1,089.9	$2,320.6
Commodity volumetric commitments:					
Natural Gas (MMBtu)	58.7	58.7	-	-	-
NGL (millions of gallons)	16.8	16.8	-	-	-

(1) Represents scheduled future maturities of consolidated debt obligations for the periods indicated.

(2) Represents interest expense on debt obligations based on interest rates as of December 31, 2012.
(3) Includes minimum payments on lease obligations for office space, railcars and tractors, and service contracts.
(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 the Partnership. 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.

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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

In general, depreciation 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. 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 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.

As of December 31, 2012, the net book value of our property, plant and equipment was $3.5 billion and we recorded $197.6 million in depreciation and amortization expense for 2012. The weighted average life of our long-lived assets, excluding the Badlands assets purchases on December 31, 2012, is approximately 20 years. We are still determining the useful lives of certain categories of tangible and intangible assets associated with our Badlands acquisition. If the useful lives of these assets were found to be shorter than originally estimated, depreciation expense may increase, liabilities for future asset retirement obligations may be insufficient and impairments in carrying values of tangible and intangible assets may result. For example, if the depreciable lives of our assets were reduced by 10%, we estimate that depreciation expense would increase by $22.0 million per year, which would result in a corresponding reduction in our operating income. In addition, if an assessment of impairment resulted in a reduction of 1% of our long-lived assets, our operating income would decrease by $35.4 million in the year of the impairment. There have been no material changes impacting estimated useful lives of the assets.

Revenue Recognition

The Partnership's 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.

Price Risk Management (Hedging)

The Partnership's 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, the Partnership has entered into derivative financial instruments related to a portion of its equity volumes to manage the purchase and sales prices of commodities. We are exposed to the credit risk of the Partnership's counterparties in these derivative financial instruments. We also monitor NGL inventory levels with a view to mitigating losses related to downward price exposure.

The Partnership's cash flow is affected by the derivative financial instruments it enters 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 the Partnership's operating results each period is the price assumptions used to value the Partnership's 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 the Partnership's derivative financial instruments was a net asset of $22.2 million as of December 31, 2012, 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. The Partnership has 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 and the Partnership would be exposed to the loss of fair value of the financial instrument transaction with that counterparty. Ignoring the adjustment for credit risk, if a bankruptcy by a financial instrument counterparty impacted 10% of the fair value of commodity-based financial instruments that are in an asset position, we estimate that the Partnership's operating income would decrease by $3.4 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 to our “Consolidated Financial Statements.”

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

Our exposure to market risk is largely derivative of the Partnership's exposure to market risk. The Partnership's principal market risks are its 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 its customers. Neither we nor the Partnership use risk sensitive instruments for trading purposes.

Commodity Price Risk

A significant portion of the Partnership's revenues are derived from percent-of-proceeds contracts under which it receives 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 the Partnership's control. The Partnership monitors these risks and enters into hedging transactions designed to mitigate the impact of commodity price fluctuations on its 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 the commodity risk management activities is to hedge the exposure to commodity price risk and reduce fluctuations in the Partnership's operating cash flow despite fluctuations in commodity prices. In an effort to reduce the variability of the Partnership's cash flows, as of December 31, 2012, the Partnership has hedged the commodity price associated with a portion of its expected (i) natural gas equity volumes in Field Gathering and Processing Operations and (ii) NGL and condensate equity volumes predominately in Field Gathering and Processing Operations as well as in the LOU portion of the Coastal Gathering and Processing Operations that result from its percent of proceeds processing arrangements by entering into derivative instruments, including swaps and purchased puts (or floors) and calls (or caps). The Partnership hedges a higher percentage of its expected equity volumes in the current year compared to future years, in which it hedges incrementally lower percentages of expected equity volumes. With swaps, the Partnership typically receives an agreed fixed price for a specified notional quantity of natural gas or NGL and it pays the hedge counterparty a floating price for that same quantity based upon published index prices. Since the Partnership receives from its 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 its actual equity volumes, the Partnership typically limits its use of swaps to hedge the prices of less than its expected natural gas and NGL equity volumes. The Partnership utilizes purchased puts (or floors) and calls (or caps) to hedge additional expected equity commodity volumes without creating volumetric risk. The Partnership may buy calls in connection with swap positions to create a price floor with upside. The Partnership intends to continue to manage its exposure to commodity prices in the future by entering into similar derivative transactions using swaps, collars, purchased puts (or floors) or other derivative instruments as market conditions permit.

The Partnership has tailored its hedges to generally match the NGL product composition and the NGL and natural gas delivery points to those of its physical equity volumes. The NGL hedges cover specific NGL products based upon the expected equity NGL composition. The Partnership believes 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 the Partnership's 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. The principal counterparties (or, if applicable, their guarantors) have investment grade credit ratings. The Partnership's 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 its senior secured indebtedness that ranks equal in right of payment with liens granted in favor of its senior secured lenders. Absent federal regulations resulting from the Dodd-Frank Act, and as long as this first priority lien is in effect, the Partnership expects to have no obligation to post cash, letters of credit or other additional collateral to secure these hedges at any time, even if a counterparty's exposure to the Partnership's credit increases over the term of the hedge as a result of higher commodity prices or because there has been a change in the Partnership's creditworthiness. A purchased put (or floor) transaction does not expose the Partnership's counterparties to credit risk, as the Partnership has no obligation to make future payments beyond the premium paid to enter into the transaction, however, the Partnership is 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.

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For all periods presented, the Partnership has entered into hedging arrangements for a portion of its forecasted equity volumes. Floor volumes and floor pricing are based solely on purchased puts (or floors). During the years ended December 31, 2012, 2011 and 2010, our operating revenues were increased (decreased) by net hedge adjustments on commodity derivative contracts of $43.2 million, $(33.9) million and $4.7 million. The net hedge adjustments that impact our consolidated revenues (but do not affect the Partnership's revenues) include amortization of OCI related to hedges terminated and re-assigned upon the Partnership's acquisition of Versado in 2010, as well as OCI related to terminations of commodity derivatives in July 2008.

As of December 31, 2012, the Partnership had the following derivative instruments which will settle during the years ending December 31, 2013 through 2015:

Natural Gas						
Instrument Type	Index	Price $/MMBtu	MMBtu 2013	2014	2015	Fair Value (in millions)
Swap	IF-WAHA	4.68	10,730	-	-	$ 4.8
Swap	IF-WAHA	3.53	-	7,000	-	(1.0)
Swap	IF-WAHA	3.53	-	-	1,750	(0.4)
Total Swaps			10,730	7,000	1,750	
Swap	IF-PB	4.69	10,084	-	-	4.7
Swap	IF-PB	3.49	-	6,000	-	(0.9)
Swap	IF-PB	3.49	-	-	1,500	(0.3)
Total Swaps			10,084	6,000	1,500	
Swap	IF-NGPL MC	4.17	5,275	-	-	1.5
Swap	IF-NGPL MC	3.45	-	5,000	-	(0.7)
Swap	IF-NGPL MC	3.46	-	-	1,250	(0.3)
Total Swaps			5,275	5,000	1,250	
Total Sales			26,089	18,000	4,500	
Natural Gas Basis Swaps						
Basis Swaps	Various Indexes, Maturities Through October 2013					(0.3)
						$ 7.1

NGL					
Instrument Type	Index	Price $/Gal	Gal 2013	2014	Fair Value (in millions)
Swap	OPIS-MB	1.05	5,650	-	$ 11.9
Swap	OPIS-MB	1.21	-	1,000	3.6
Total Swaps			5,650	1,000	
					$ 15.5

Condensate					
Instrument Type	Index	Price $/Bbl	Bbl 2013	2014	Fair Value (in millions)
Swap	NY-WTI	93.34	1,795	-	$ 0.1
Swap	NY-WTI	90.03	-	700	(0.5)
Total Sales			1,795	700	
					$ (0.4)

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

The Partnership accounts for the fair value of its 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. The Partnership values its 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 the Partnership is 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 15 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 TRC Revolver. The Partnership is exposed to the risk of changes in interest rates, primarily as a result of variable rate borrowings under its TRP Revolver. As of December 31, 2012, neither we nor the Partnership have any interest rate hedges. However, we or the Partnership 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 TRC Revolver and the TRP Revolver will also increase. As of December 31, 2012, the Partnership had $620.0 million in variable rate borrowings under its TRP Revolver and we had variable rate borrowings of $82.0 million under our TRC Revolver. A hypothetical change of 100 basis points in the interest rate of variable rate debt would impact the Partnership's annual interest expense by $6.2 million and the TRC Non-Partnership annual interest expense by $0.8 million.

Counterparty Credit Risk

The Partnership is subject to risk of losses resulting from nonpayment or nonperformance by its 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, the Partnership's 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, the Partnership may sustain a loss and its cash receipts could be negatively impacted.

As of December 31, 2012, affiliates of Wells Fargo Bank N.A. ("Wells Fargo"), Barclays PLC ("Barclays"), Securities Americas LLC ("Natixis"), Credit Suisse Group AG ("Credit Suisse") and Bank of America Merrill Lynch ("BAML") accounted for 31%, 16%, 15%, 11% and 10% of the Partnership's counterparty credit exposure related to commodity derivative instruments. Wells Fargo, Barclays, Natixis, Credit Suisse and BAML 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

The Partnership extends credit to customers and other parties in the normal course of business. The Partnership has established various procedures to manage its credit exposure, including initial credit approvals, credit limits and terms, letters of credit and rights of offset. The Partnership also uses prepayments and guarantees to limit credit risk to ensure that its established credit criteria are met.

The Partnership has 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 the Partnership’s third-party accounts receivable, annual operating income would decrease by $5.1 million in the year of the assessment.

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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, 2012 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 Securities and Exchange Commission 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 Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the results of this evaluation, management concluded that the internal control over financial reporting was effective as of December 31, 2012, 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.

The business of Saddle Butte Pipeline, LLC that the Partnership purchased on December 31, 2012 was excluded from the scope of our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2012. This business constituted 20.1% of our total assets as of December 31, 2012.

(b) Changes in Internal Control Over Financial Reporting

During the three months ended December 31, 2012, 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.

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PART III

Item 10. Directors, Executive Officers and Corporate Governance.

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

Our directors hold office until the earlier of their death, resignation, removal or disqualification or until their successors have been elected and qualified. Officers serve at the discretion of the board of directors. There are no family relationships among any of our directors or executive officers. Please read "Certain Relationships and Related Transactions—Stockholders' Agreement" for a discussion of arrangements among our stockholders pursuant to which our directors were selected prior to our IPO. The following table sets forth certain information with respect to our directors, executive officers and other officers as of February 15, 2013.

Name	Age	Position
Rene R. Joyce	65	Executive Chairman of the Board and Director
Joe Bob Perkins	52	Chief Executive Officer and Director
James W. Whalen	71	Advisor to Chairman and CEO and Director
Michael A. Heim	64	President and Chief Operating Officer
Jeffrey J. McParland	58	President-Finance and Administration
Roy E. Johnson	68	Executive Vice President
Paul W. Chung	52	Executive Vice President, General Counsel and Secretary
Matthew J. Meloy	35	Senior Vice President, Chief Financial Officer and Treasurer
John R. Sparger	59	Senior Vice President and Chief Accounting Officer
Charles R. Crisp	65	Director
In Seon Hwang	36	Director
Peter R. Kagan	44	Director
Chris Tong	56	Director
Ershel C. Redd Jr.	65	Director

Rene R. Joyce has served as Executive Chairman of the Board of TRC, the general partner and TRI since January 1, 2012 and as a director of the Company since its formation on October 27, 2005 and of the general partner since October 2006. Mr. Joyce previously served as Chief Executive Officer of the Company between October 27, 2005 and December 31, 2011, the 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 the Company, the general partner and TRI since January 1, 2012. Mr. Perkins previously served as President of the Company between the date of its formation on October 27, 2005 and December 31, 2011, of the 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 the Company, derived from his service as President from its founding through 2011 and his current service as Chief Executive Officer and director, coupled with his broad experience in the oil and gas industry, and specifically in the midstream sector, his engineering and business educational background and his experience with the investment community enable Mr. Perkins to provide a valuable and unique perspective to the board on a range of business and management matters.

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

Michael A. Heim has served as President and Chief Operating Officer of the Company, the general partner and TRI since January 1, 2012. Mr. Heim previously served as Executive Vice President and Chief Operating Officer of the Company between the date of its formation on October 27, 2005 and December 2011, of the 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 the Company and TRI since October 25, 2010 and of the general partner since December 15, 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 the Company 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 the general partner between October 2006 and December 15, 2010 and served as a director of the general partner from October 2006 to February 2007. Mr. McParland served as Treasurer of the Company from October 27, 2005 until May 2007, of the 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.

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Roy E. Johnson has served as Executive Vice President of the Company since its formation on October 27, 2005, of the general partner since October 2006 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 the Company since its formation on October 27, 2005, of the general partner since October 2006 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 the Company and TRI since October 25, 2010 and of the general partner since December 15, 2010. Mr. Meloy served as Vice President — Finance and Treasurer of the Company and TRI between April 2008 and October 2010, and as Director, Corporate Development of the Company and TRI between March 2006 and March 2008 and of the general partner between March 2006 and March 2008. He has served as Vice President — Finance and Treasurer of the general partner between April 2008 and December 15, 2010. Mr. Meloy was with The Royal Bank of Scotland in the structured finance group, focusing on the energy sector from October 2003 to March 2006, most recently serving as Assistant Vice President.

John R. Sparger has served as Senior Vice President and Chief Accounting Officer of the Company and TRI since January 2006 and of the general partner since October 2006. Mr. Sparger served as Vice President, Internal Audit of the Company 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.

Charles R. Crisp has served as a director of the Company since its formation on October 27, 2005 and of TRI between February 2004 and December 2010. Mr. Crisp was President and Chief Executive Officer of Coral Energy, LLC, a subsidiary of Shell Oil Company from 1999 until his retirement in November 2000, and was President and Chief Operating Officer of Coral from January 1998 through February 1999. Prior to this, Mr. Crisp served as President of the power generation group of Houston Industries and, between 1988 and 1996, as President and Chief Operating Officer of Tejas. Mr. Crisp is also a director of AGL Resources Inc., EOG Resources Inc. and IntercontinentalExchange, Inc. Mr. Crisp brings extensive energy experience, a vast understanding of many aspects of our industry and experience serving on the boards of other public companies in the energy industry. His leadership and business experience and deep knowledge of various sectors of the energy industry bring a crucial insight to the board of directors.

In Seon Hwang has served as a director of the Company since May 2006, of TRI between May 2006 and December 2010 and the general partner since February 2011. 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 Competitive Power Ventures, Gulf Coast Energy Resources, LLC, Omega Energia Renovavel S.A. and Venari LLC and serves on the investment committee of Sheridan Production Partners LLC. Mr. Hwang was appointed as a director because certain investment funds managed by Warburg Pincus LLC, for whom Mr. Hwang is a managing director and member, previously controlled us through their ownership of securities in Targa Resources Corp. 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.

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Peter R. Kagan has served as a director of the Company since its formation on October 27, 2005, of the general partner since February 2007 and of TRI between February 2004 and December 2010. Mr. Kagan is a member and Managing Director of Warburg Pincus LLC and a general partner of Warburg Pincus & Co., where he has been employed since 1997 and became a partner of Warburg Pincus & Co. in 2002. He is also a member of Warburg Pincus' Executive Management Group. He is also a director of Antero Resources Corporation, Asian Amercian Gas, Inc., Canbriam Energy, Fairfield Energy Limited, Hawkwood Energy LLC, Laredo Petroleum, MEG Energy Corp. and Venari Resources LLC. Mr. Kagan was appointed as a director because certain investment funds managed by Warburg Pincus LLC, for whom Mr. Kagan is a managing director and member, previously controlled us through their ownership of securities in Targa Resources Corp. Mr. Kagan 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.

Chris Tong has served as a director of the Company since January 2006 and of TRI between January 2006 and December 2010. Mr. Tong is a director of Kosmos Energy Ltd. He also served as a director of Cloud Peak Energy Inc. from October 2009 until May 2012. He served as Senior Vice President and Chief Financial Officer of Noble Energy, Inc. from January 2005 until August 2009. He also served as Senior Vice President and Chief Financial Officer for Magnum Hunter Resources, Inc. from August 1997 until December 2004. Prior thereto, he was Senior Vice President of Finance of Tejas Acadian Holding Company and its subsidiaries, including Tejas Gas Corp., Acadian Gas Corporation and Transok, Inc., all of which were wholly-owned subsidiaries of Tejas Gas Corporation. Mr. Tong held these positions from August 1996 until August 1997, and had served in other treasury positions with Tejas since August 1989. Mr. Tong brings a breadth and depth of experience as a chief financial officer in the energy industry, a financial executive, a director of other public companies and a member of other audit committees. He brings significant financial, capital markets and energy industry experience to the board and in his position as the chairman of our Audit Committee.

Ershel C. Redd Jr. has served as a director of the Company since February 2011. Mr. Redd has served as a consultant in the energy industry since 2008 providing advice to various energy companies and investors regarding their operations, acquisitions and dispositions. Mr. Redd was President and Chief Executive Officer of El Paso Electric Company, a public utility company, from May 2007 until March 2008. Prior to this, Mr. Redd served in various positions with NRG Energy, Inc., a wholesale energy company, including as Executive Vice President – Commercial Operations from October 2002 through July 2006, as President – Western Region from February 2004 through July 2006, and as a director between May 2003 and December 2003. On May 14, 2003, NRG filed for protection under Chapter 11 of the Federal Bankruptcy Code. On November 24, 2003, NRG's Chapter 11 Plan of Reorganization was confirmed. Mr. Redd served as Vice President of Business Development for Xcel Energy Markets, a unit of Xcel Energy Inc., from 2000 through 2002, and as President and Chief Operating Officer for New Century Energy's (predecessor to Xcel Energy Inc.) subsidiary, Texas Ohio Gas Company, from 1997 through 2000. Mr. Redd brings to the Company extensive energy industry experience, a vast understanding of varied aspects of the energy industry and experience in corporate performance, marketing and trading of natural gas and natural gas liquids, risk management, finance, acquisitions and divestitures, business development, regulatory relations and strategic planning. His leadership and business experience and deep knowledge of various sectors of the energy industry bring a crucial insight to the board of directors.

Board of Directors

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

Our directors are divided into three classes serving staggered three-year terms. Class I, Class II and Class III directors will serve until our annual meetings of stockholders in 2014, 2015 and 2013, respectively. The Class I directors are Messrs. Crisp and Whalen, the Class II directors are Messrs. Redd, Perkins and Hwang and the Class III directors are Messrs. Kagan, Tong and Joyce. At each annual meeting of stockholders, directors will be elected to succeed the class of directors whose terms have expired. This classification of our board of directors could have the effect of increasing the length of time necessary to change the composition of a majority of the board of directors. In general, at least two annual meetings of stockholders will be necessary for stockholders to effect a change in a majority of the members of the board of directors.

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Committees of the Board of Directors

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

Audit Committee

The members of our Audit Committee are Messrs. Tong, Redd and Crisp. Mr. Tong is the Chairman of this committee. Our board of directors has affirmatively determined that Messrs. Crisp, Redd, and Tong are independent as described in the rules of the NYSE and the Exchange Act. Our board of directors has also determined that, based upon relevant experience, Mr. Tong is an "audit committee financial expert" as defined in Item 407 of Regulation S-K of the Exchange Act.

This committee oversees, reviews, acts on and reports on various auditing and accounting matters to our board of directors, including: the selection of our independent accountants, the scope of our annual audits, fees to be paid to the independent accountants, the performance of our independent accountants and our accounting practices. In addition, the Audit Committee oversees our compliance programs relating to legal and regulatory requirements. We have adopted an Audit Committee charter defining the committee's primary duties in a manner consistent with the rules of the SEC and NYSE or market standards.

Compensation Committee

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

Nominating and Governance Committee

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

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

Conflicts Committee

The members of our Conflicts Committee are Messrs. Crisp, Redd and Tong. Mr. Tong is the Chairman of this committee. This Committee reviews matters of potential conflicts of interest, as directed by our board of directors. We adopted a Conflicts Committee charter defining the committee's primary duties.

Corporate Governance

Code of Business Conduct and Ethics

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

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Available Information

We make available, free of charge within the "Corporate Governance" section of our website at www.targaresources.com and in print to any stockholder who so requests, our Corporate Governance Guidelines, Code of Ethics, Code of Conduct, Audit Committee Charter, Compensation Committee charter and Nominating and Governance Committee charter. Requests for print copies may be directed to: Investor Relations, Targa Resources Corp., 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 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. Peter Kagan.

Interested parties may communicate directly with our non-management directors by writing to: Non-Management Directors, Targa Resources Corp., 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% stockholders to file with the SEC reports of ownership and changes in ownership of our equity securities. Based solely upon a review of the copies of the Form 3, 4 and 5 reports furnished to us and certifications from our directors and executive officers, we believe that during 2012, 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.

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Item 11. Executive Compensation.

Compensation Discussion and Analysis

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

Overview

Compensatory arrangements with our executive officers identified in the Summary Compensation Table (“named executive officers”) are approved by the Compensation Committee of our Board of Directors (the “Compensation Committee”). For 2012, our named executive officers 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 named executive officers also serve as executive officers of the general partner. We own a 14.5% interest in the Partnership, including the 2% general partner interest, and are the indirect parent of the general partner. The compensation information described in this Compensation Discussion and Analysis and contained in the tables that follow reflects all compensation received by our named executive officers for the services they provide to us and for the services they provide to the general partner and the Partnership for the years covered.

All decisions regarding this compensation are made by 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 the 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 the Partnership’s business and affairs. During 2012, the Partnership reimbursed us and our affiliates for the compensation of our named executive officers pursuant to the Partnership Agreement and the terms, and subject to the limitations, of the Omnibus Agreement, which will expire in April 2013. See “Item 13. Certain Relationships and Related Transactions, and Director Independence—Omnibus Agreement” for additional information regarding the Partnership’s reimbursement obligations for 2012 and for 2013 following the expiration of the Omnibus Agreement.

The Compensation Committee believes that the actions it has taken to govern compensation in a responsible way as described in this CD&A and the Company’s performance over its relative brief trading history will demonstrate that our compensation programs are structured to pay reasonable amounts for performance based on our understanding of the markets and that our shareholders have realized substantial returns since our public offering.

At our 2011 Annual Meeting, more than 99% of the votes cast by our shareholders approved the compensation paid to our named executive officers as described in the CD&A and the other related compensation tables and disclosures contained in our Proxy Statement filed with the SEC on April 4, 2011. The Board of Directors and the Compensation

Committee reviewed the results of this vote and concluded that with this level of support, no changes to our compensation design and philosophy needed to be considered as a result of the vote. In accordance with the preference expressed by our shareholders to conduct an advisory vote on executive compensation every three years, the next advisory vote will occur at our 2014 Annual Meeting.

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Summary of 2012 Compensation Decisions

While the compensation arrangements for our named executive officers during fiscal 2012 remained substantially similar to those in place during fiscal 2011, specific compensatory changes in 2012 included the following:

- Base salary raises were approved for our named executive officers, ranging from 2.4% to 17.0%. The larger adjustments approved for Mr. Heim and Mr. Meloy were implemented to reflect the increased responsibilities of these named executive officers in connection with organizational restructurings of executive roles and duties.

- Mr. Meloy's target bonus amount under our annual incentive plan was increased to 50% of his base salary from 40% of his base salary in 2011, in order to reflect his promotion to Chief Financial Officer. The target bonus amounts for all other named executive officers did not change from 2011.

- On January 12, 2012, we adopted the Executive Change in Control Program, which provides "double trigger" benefits, including cash payments, to our named executive officers following a qualifying termination in connection with a change in control event. Under a "double trigger" plan, both a change in control and a qualifying termination must occur in order for an executive to be entitled to the change in control benefits. We believe these post-termination change in control benefits are appropriately aligned with shareholder interests are important in attracting and retaining qualified executives and are in line with similar benefits provided by our Peer Group and other companies with which we compete for executive talent.

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, which is a leading provider of midstream natural gas and natural gas liquid services in the United States. As described in "Management's Discussion and Analysis of Financial Conditions and Results of Operations" in our Annual Report on Form 10-K, our 2012 financial results and the 2012 financial results of the Partnership as well as the 2012 strategic and operational accomplishments were both significant improvements relative to 2011 results. In summary, some of our more significant financial, operational and strategic highlights in 2012 included:

- On balance, excellent execution across our businesses offset by weaker commodity prices, with the Partnership's EBITDA nonetheless at the low end of public guidance;

- Excellent execution on announced expansion projects;

- Launch of additional expansion projects;

- Continued development of our potential future expansion project portfolio;

- Successful negotiation of the agreement for and closing of the acquisition of a Bakken shale midstream business;

- A strong track record and performance regarding safety and compliance with all aspects of our business, including environmental and regulatory compliance.

See "Components of Executive Compensation Program for Fiscal 2012—Annual Cash Incentive Bonus" for further detail regarding the above summary highlights.

Consistent with, and in recognition of, these achievements, in January 2013 we awarded 2012 annual cash incentive bonuses to our named executive officers at 165% of the target level. We also approved base salary raises to bring our named executive officers more closely in line with salaries provided to executives at companies within our Peer Group, adjusted for company size. The 2013 annual incentive bonus target was increased for Mr. Perkins to be more in line with those of chief executive officers at our Peer Group companies and the long-term equity incentive award opportunity for 2013 for Messrs. Perkins and Heim was increased to be more in line with those provided to executives at companies within our Peer Group, in all cases adjusted for company size. See "Role of Peer Group and Benchmarking" for a description of our Peer Group companies for 2012, including the regression methodology used by BDO USA, LLC, the compensation consultant engaged by the Compensation Committee (the "Compensation Consultant"), to adjust for company size, and see "Changes for 2013" for additional information regarding base salary and incentive bonus opportunity increases effected for fiscal 2013.

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Discussion and Analysis of Executive Compensation

Compensation Philosophy

The Compensation Committee believes that total compensation for our executives should be 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 "Role of Peer Group and Benchmarking" below. 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 provide a competitive total compensation program that enables us to attract and retain key executives.

- Accountability for Performance. The Compensation Committee believes our executive compensation program should ensure an alignment between our strategic 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.

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Consistent with this philosophy and the compensation objectives, our executive compensation program is 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 are tied to achievement of annual financial, operational and strategic business priorities and are 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 total target 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" 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 2012 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.

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The approximate allocation of total direct compensation for our named executive officers in fiscal 2012 is presented below. This reflects (i) the salary rates in effect as of December 31, 2012, (ii) target annual cash incentive bonuses for services performed in fiscal 2012, and (iii) the grant date fair value of long-term equity incentive awards granted during fiscal 2012.

Fiscal 2012 Total Direct Compensation

	Rene J. Joyce	Joe Bob Perkins	James W. Whalen	Michael A. Heim	Matthew J. Meloy
Base Salary	26%	29%	32%	31%	39%
Annual Cash Incentive Bonus	26%	23%	25%	24%	20%
Long-Term Equity Incentive Awards	48%	48%	43%	45%	41%
Total	100%	100%	100%	100%	100%

In the two full calendar years since our December 2010 public offering, 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 70% of the market total compensation level that our Peer Group company-based regression models predict for a company of our size as measured by 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 decrease in the Chief Executive Officer target from 2010 to 2011 corresponds to Mr. Perkin's appointment to that position for 2011.

Because incentive compensation comprises 72% of our Chief Executive Officer's total compensation opportunity, the amount of compensation he may realize 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 and the total return of our common stock relative to peer companies.

In the two full calendar years since our December 2010 public offering, we have delivered annual total return to our shareholders of 55.2% and 33.6%, respectively.

Methodology and Process

Role of Peer Group and Benchmarking

When evaluating compensation levels for each named executive officer, the Compensation Committee, with the assistance of the Compensation Consultant, reviews publicly available compensation data for executives in our Peer Group and compensation surveys and uses that information to set compensation levels for the named executive officers in the context of their roles and levels of responsibility, accountability and decision-making authority and in the context of company size relative to the Peer Group. 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 the compensation 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.

The Peer Group considered by the Compensation Committee in consultation with senior management for compensation comparison purposes includes midstream master limited partnerships ("MLPs") and other energy utilities and exploration and production companies to reflect the market in which we compete for executive talent. Our analysis places greater weight on the compensation data reported by other publicly-traded midstream partnerships that are comparable to us in size as measured by market capitalization and total assets. Utilities and exploration and production companies 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 are larger than us 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 peer group and is then weighted as follows to develop a reference point for assessing our total executive pay opportunity relative to market practice: MLPs (given a 70% weighting), exploration and production companies ("E&Ps") (given a 15% weighting) and utility companies (given a 15% weighting). For 2012, the "Peer Group" companies were:

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

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

- Utility peer companies: Centerpoint Energy Inc., Dominion Resources Inc., Enbridge Inc., EQT Corp., National Fuel Gas Co., NiSource Inc., ONEOK Inc., Questar Corp., Sempra Energy, Spectra Energy Co., Southern Union Co., TransCanada Corporation and Williams Companies Inc.

Senior management and the Compensation Committee review our compensation-setting practices and Peer Group companies on at least an annual basis.

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 key 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.

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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 has no other role in determining compensation for our named executive officers, although the Compensation Committee may delegate the approval of award grants and other transactions and responsibilities regarding the administration of compensatory programs to the Executive Chairman of the Board or the Chief Executive Officer, provided that such administration and approval of awards does not apply for 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 2012

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 long-term equity incentive award component of our compensation program.

For 2012, the Compensation Committee authorized increases in base salary for our named executive officers, effective March 1, 2012, as set forth in the following table. Salaries for all named executive officers were increased to recognize outstanding performance and to better align their salaries with data generated in our Compensation Consultant’s Peer Group analysis regarding expected compensation for companies of our size. The increases for Messrs. Heim and Meloy were more significant to reflect their increased responsibilities within the organization.

	Prior Salary	Base Salary Effective March 1, 2012	Percent Increase
Rene R. Joyce	$ 547,000	$ 560,000	$ 2.4 %
Joe Bob Perkins	468,000	480,000	2.6 %
James W. Whalen	468,000	480,000	2.6 %
Michael A. Heim	415,000	460,000	10.8 %
Matthew J. Meloy	235,000	275,000	17.0 %

Annual Cash Incentive Bonus

For 2012, our named executive officers were eligible to receive annual cash incentive bonuses under the 2012 Annual Incentive Plan (the “2012 Bonus Plan”), which was approved by the Compensation Committee in January 2012. 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.

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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 2012 Bonus Plan. Each participant's target bonus amount is equal to the product of the participant's base salary and the participant's target bonus percentage, which may generally range from 6.0% to 100%. For purposes of the 2012 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	80 %	384,000
James W. Whalen	80 %	384,000
Michael A. Heim	80 %	368,000
Matthew J. Meloy	50 %	137,500

Mr. Meloy's target bonus percentage was increased from 40% to 50%, effective January 12, 2012, to recognize his increased responsibilities as our Chief Financial Officer.

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 2012 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 2012 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.

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2012 Business Priority	Committee Consensus	Overall Assessment
Continue to control all operating, capital and general and administrative costs	Achieved	· On balance, excellent execution across our businesses offset by weaker commodity prices, with the Partnership's EBITDA nonetheless at the low end of public guidance: · Excellent execution on: volume growth for Field Gathering and Processing, fractionation and exports; major project execution; new growth projects and commercial arrangements; expense control; distribution and dividend growth; credit, inventory, hedging and balance sheet management; and, capital markets execution and investor relations · Somewhat offset by commodity prices, lower Coastal Gathering and Processing volumes and start-up issues related to our non-operated Gulf Coast Fractionator expansion · Excellent execution on announced expansion projects including: start-up of the benzene saturation and de-ethanizer and of the semi-refrigerated HD5 propane export; and Sound Terminal expansion on schedule (at revised budget) and Cedar Bayou Fractionator ("CBF") Train 4 expansion and International Export Project on schedule and budget · Launch of additional expansion projects including: 30 MMcf/d plants at both SAOU and Sand Hills ; 200 MMcf/d plant in North Texas; and phase 2 of the International Export Project · Continued development of our potential future expansion project portfolio including: engineering and permitting for CBF Train 5 and for unit train facilities and the Sound and Stockton Terminals; and potential processing expansions in the Permian Basin · Successful negotiation of agreement for and closing of acquisition of Bakken shale midstream business · Strong track record and performance regarding safety and compliance with all aspects of our business, including environmental and regulatory compliance.
Invest in our businesses	Exceeded	
Continue priority emphasis and strong performance relative to a safe workplace	Achieved	
Reinforce business philosophy and mindset that promotes compliance with all aspects of our business including environmental and regulatory compliance	Achieved	
Continue to tightly manage credit, inventory, interest rate and commodity price exposures	Achieved	
Execute on major capital and development projects, such as finalizing negotiations, completing projects on time and on budget, and optimizing economics and capital funding	Exceeded	
Pursue selected growth opportunities, including new gathering and processing build-outs, fee-based capital expenditure projects and potential purchases of strategic assets	Exceeded	
Pursue commercial and financial approaches to achieve maximum value and manage risks	Exceeded	
Execute on all business dimensions, including the financial business plan	Exceeded	

After reviewing the 2012 Business Priorities, Results and Overall Assessment as summarized above, in January, 2013, the Compensation Committee, in its sole discretion, approved a cash bonus pool equal to 165% of the target level under the 2012 Bonus Plan. The Compensation Committee determined to pay these above target level bonuses because it considered overall performance, including organizational performance, to have substantially exceeded expectations in 2012 based on its assessment of the key business priorities it established for 2012 despite deterioration in commodity prices.

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 key business priorities. This subjective evaluation that performance had substantially exceeded expectations occurred with the background and ongoing context of (i) refinements of the 2012 business priorities by the Board of Directors and the Compensation Committee both before the beginning of and during the year, (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 2012. 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.

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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 2012 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 165% of the target amount, each named executive officer was awarded a bonus amount equal to 165% 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 execution of multiple capital markets transactions during 2012 and leading in 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 2012 Bonus Plan to be paid by February 28, 2013 are as follows:

	Target Bonus Amount	Individual Performance Factor	Company Performance Factor	Actual Bonus Amount
Rene R. Joyce	$ 560,000	1.0	1.65	$924,000
Joe Bob Perkins	384,000	1.0	1.65	633,600
James W. Whalen	384,000	1.0	1.65	633,600
Michael A. Heim	368,000	1.0	1.65	607,200
Matthew J. Meloy	137,500	1.25	1.65	283,594

Long-Term Equity Incentive Awards

In connection with our initial public offering in December 2010 (the "IPO"), 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, 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 at the beginning of each year.

For 2012, 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.

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The Compensation Committee believes that the combination of equity awards consisting of restricted stock (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 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 12, 2012, our named executive officers were awarded restricted shares of our common stock under the Stock Incentive Plan in the following amounts: (i) 6,565 restricted shares to Mr. Joyce, (ii) 5,035 restricted shares to Mr. Perkins, (iii) 4,235 restricted shares to Mr. Whalen, (iv) 4,399 restricted shares to Mr. Heim, and (v) 1,866 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.

Equity-Settled Performance Unit Awards. Our named executive officers also receive awards of equity-settled performance unit awards under the Partnership's Long-Term Incentive Plan. The vesting of these awards is dependent on the Partnership's performance relative to the performance of a specified comparator group of publicly-traded partnerships (the "LTIP Peer Group"). These 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 12, 2012, our named executive officers were awarded equity-settled performance units under the Partnership's Long-Term Incentive Plan in the following amounts: (i) 21,240 performance units to Mr. Joyce, (ii) 16,290 performance units to Mr. Perkins, (iii) 13,702 performance units to Mr. Whalen, (iv) 14,233 performance units to Mr. Heim, and (v) 6,039 performance units to Mr. Meloy.

The performance period for the 2012 performance unit awards began on June 30, 2012 and ends on June 30, 2015. Provided a named executive officer remains continuously employed throughout the performance period, his 2012 performance units will vest on June 30, 2015 and will be settled as soon as practicable following the vesting date by the issuance of a number of Partnership common units 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 2012 performance unit awards, the LTIP Peer Group is composed of the Partnership and the following other companies:

Copano Energy, L.L.C.	MarkWest Energy Partners, LP
Crosstex Energy, LP	Martin Midstream Partners LP
DCP Midstream Partners, LP	ONEOK Partners, LP
Enbridge Energy Partners LP	Plains All American Pipeline L.P.
Energy Transfer Partners, LP	Regency Energy Partners LP
Magellan Midstream Partners, LP	Williams Partners LP

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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 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.

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 the average closing price per share/unit for the first ten trading days of the performance period (the "Beginning Price") from the sum of (a) the average closing price per share/unit for the last ten trading days ending on the date that is 15 days prior to the end of the performance period, plus (b) the aggregate amount of dividends/distributions paid with respect to a share/unit during such period (such result is referred to as the "Value Increase"), and (ii) dividing the Value Increase by the Beginning Price. During the period the performance unit awards 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 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 measured over the period beginning in June 30 of each year in which the long-term incentive awards were made, using the Beginning Price described above, and continuing through January 10, 2013.

Severance and Change in Control Benefits. On January 12, 2012, the Compensation Committee adopted the Executive Officer Change in Control Program (the "Change in Control Program"), in which each of our named executive officers is eligible to participate. Prior to 2012, none of our named executive officers (other than Mr. Meloy) was eligible to participate in any arrangement providing cash payments upon a change in control or specified termination of employment events. The Change in Control Program provides for post-termination payments following a qualifying termination 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.

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

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

Changes for 2013

Base Salary

The Compensation Committee authorized, and executive management will implement, the following increased base salaries for our named executive officers effective March 1, 2013.

	Effective March 1, 2013	Current Salary
Rene R. Joyce	$ 560,000	$ 560,000
Joe Bob Perkins	525,000	480,000
James W. Whalen	480,000	480,000
Michael A. Heim	485,000	460,000
Matthew J. Meloy	325,000	275,000

Mr. Joyce and Mr. 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 more closely align the total direct compensation of these individuals with the total direct compensation provided to similarly situated executives at companies within our Peer Group, adjusted for company size and to reflect professional growth and the assumption of additional responsibilities. The analysis provided to the Compensation Committee by the

Compensation Consultant indicates that the 2013 total target direct compensation of our Chief Executive Officer remains more than 25% below the competitive amount suggested by the market trend line that was developed through regression analysis of Peer Group pay programs.

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Annual Cash Incentive Bonus

In preparing our business plan for 2013, senior management developed and proposed a set of business priorities to the Compensation Committee. The Compensation Committee adopted the business priorities proposed by senior management, with certain modifications requested by the Compensation Committee, for purposes of the 2013 Annual Incentive Plan (the "2013 Bonus Plan"). The 2013 business priorities are similar to those in effect for 2012 and have been revised to reflect a focus on EBITDA and distribution/dividend growth, our recent Bakken shale midstream acquisition and retaining qualified talent, and specifically include the following:

- execute on all business dimensions, including 2013 guidance for EBITDA and distribution/dividend growth as furnished from time to time,
- successfully integrate and commercialize the Bakken shale midstream acquisition including contribution to 2013 guidance,
- 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 2013 Bonus Plan remain the same as for the 2012 Bonus Plan. In addition, the target bonus percentage (as a percentage of base salary) for each named executive officer (other than Mr. Perkins) remains the same for 2013. Mr. Perkins' target bonus percentage for 2013 has been increased from 80% of base salary to 100% of base salary in order to more closely align his total direct compensation with the total direct compensation provided to similarly situated chief executive officers at companies within our Peer Group, adjusted for company size. As with the 2012 Bonus Plan, 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.

Long-Term Incentive Awards

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.

Equity-Settled Performance Unit Awards. 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) 13,709performance units to Mr. Whalen, (iv) 18,405 performance units to Mr. Heim, and (v) 7,465 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 12, 2012, except that the performance period for the 2013 awards will begin on June 30, 2013 and end on June 30, 2016. Please see "Components of Executive Compensation Program for Fiscal 2012– Long-Term Equity Incentive Awards—Equity-Settled Performance Unit Awards."

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Other Compensation Matters

Accounting Considerations. We account for the equity compensation expense for our employees, including our named executive officers, under the rules of the 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 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 has reviewed the relationship between our risk management policies and compensation policies and practices and has concluded that we do not have any compensation policies or practices that expose us to excessive or unnecessary risks that are reasonably likely to have a material adverse effect on us. Because our Compensation Committee retains the sole discretion for determining the actual amount paid to executives pursuant to our annual cash incentive bonus program, our Compensation Committee is able to assess the actual behavior of our executives as it relates to risk-taking in awarding bonus amounts. Further, our use of long-term equity incentive compensation serves our executive compensation program's goal of aligning the interests of executives and shareholders, thereby reducing the incentives to unnecessary risk-taking.

Compensation Committee Report

Messrs. Crisp, Hwang and Kagan are the current members of our Compensation Committee. In fulfilling its oversight responsibilities, the Compensation Committee has reviewed and discussed with management the Compensation Discussion and Analysis contained in our Annual Report on Form 10-K for the year ended December 31, 2012 and in this proxy statement. Based on these reviews and discussions, the Compensation Committee recommended to our Board of Directors that the Compensation Discussion and Analysis be included in our Annual Report on Form 10-K for the year ended December 31, 2012 and in this proxy statement for filing with the SEC.

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

The Compensation Committee

Charles R. Crisp, Chairman   Peter R. Kagan   In Seon Hwang

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Executive Compensation Tables

Summary Compensation Table for 2012

The following Summary Compensation Table sets forth the compensation of our named executive officers for 2012, 2011 and 2010. 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 Compensation
Joe Bob Perkins	2012	$ 478,000	$ 633,600	$ 784,417	$ 21,181	$ 1,917,198
Chief Executive Officer	2011	454,000	748,800	542,079	20,715	1,765,594
	2010	361,250	823,191	3,831,960	20,448	5,036,849
Matthew J. Meloy	2012	268,333	283,594	290,776	20,210	862,913
Senior Vice President, Chief	2011	228,125	235,000	160,859	19,771	643,755
Financial Officer and Treasurer	2010	195,625	224,100	493,350	19,740	932,815
Rene R. Joyce	2012	557,833	924,000	1,022,777	27,739	2,532,349
Executive Chairman of	2011	529,000	1,094,000	979,380	23,394	2,625,774
the Board of Directors	2010	410,000	1,120,067	5,358,408	22,410	6,910,885
James W. Whalen	2012	478,000	633,600	659,793	30,580	1,801,973
Advisor to Chairman and CEO	2011	454,000	748,800	542,079	29,587	1,774,466
	2010	356,750	593,280	3,831,960	22,338	4,804,328
Michael A. Heim	2012	452,500	607,200	685,357	23,188	1,768,245
President and Chief Operating	2011	403,500	664,000	480,517	22,400	1,570,417
Officer	2010	328,000	1,469,275	2,699,620	21,776	4,518,671

(1) For 2012, represents payments pursuant to our 2012 Bonus Plan. Please see "—Components of Executive Compensation Program for Fiscal 2012—Annual Cash Incentive Bonus." Note that, in prior filings, the payments reported under this column for 2010 were reported in the "Non-Equity Incentive Plan Compensation" column. 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 2012 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 2012. Detailed information about the amount recognized for specific awards is reported in the table under "—Grants of Plan-Based Awards for 2012" below. The grant date fair value of each restricted share subject to the restricted stock awards granted on January 12, 2012, assuming vesting will occur, is $38.72. The grant date fair value of each performance unit subject to the equity-settled performance unit awards granted on January 12, 2012 is $41.54, computed in accordance with FASB ASC Topic 718. 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 12, 2012 for each named executive officer is as follows: Mr. Joyce - $1,323,464; Mr. Meloy - $376,311; Mr. Perkins - $1,015,030; Mr. Whalen - $853,772; and Mr. Heim - $886,879.

(3) For 2012 "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 coverage provided by the Company.

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Name	401(k) and Profit Sharing Plan	Dollar Value of Life Insurance	Total
Joe Bob Perkins	$ 20,000	$1,181	$21,181
Matthew J. Meloy	20,000	210	20,210
Rene R. Joyce	20,000	7,739	27,739
James W. Whalen	20,000	10,580	30,580
Michael A. Heim	20,000	3,188	23,188

Grants of Plan Based Awards for 2012

The following table and the footnotes thereto provide information regarding grants of plan-based equity awards made to the named executive officers during 2012:

		Estimated Future Payouts Under Equity Incentive Plan Awards (#) (1)				
Name	Grant Date	Threshold (#)	Target (#)	Maximum (#)	All Other Stock Awards: Number of Shares of Stock or Units (1)	Grant Date Fair Value of Equity Awards (2)
Mr. Perkins	01/12/12				5,035	194,955
	01/12/12	5,816	16,290	24,435		589,462
Mr. Meloy	01/12/12				1,866	72,252
	01/12/12	2,156	6,039	9,059		218,524
Mr. Joyce	01/12/12				6,565	254,197
	01/12/12	7,583	21,240	31,860		768,580
Mr. Whalen	01/12/12				4,235	163,979
	01/12/12	4,892	13,702	20,553		495,814
Mr. Heim	01/12/12				4,399	170,329
	01/12/12	5,081	14,233	21,350		515,028

(1) The grants on January 12, 2012 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 2012—Long-Term Equity Incentive Awards—Equity-Settled Performance Unit Awards."

(2) The dollar amounts shown for the restricted stock awards granted on January 12, 2012 are determined by multiplying the shares reported in the table by $38.72, 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 12, 2012 are determined by multiplying the number of units equal to approximately 87% of the number of units reported in the table under the "Target" column by $41.54, 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 2012 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 2012 restricted stock awards under our Stock Incentive Plan and the 2012 equity-settled performance unit awards under the Partnership's Long-Term Incentive Plan, such as the vesting schedule of such awards, any applicable performance-based conditions, and the extent to which dividends and distributions are paid with respect to such awards.

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Outstanding Equity Awards at 2012 Fiscal Year-End

The following table and the footnotes related thereto provide information regarding equity-based awards outstanding as of December 31, 2012 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	36,477	$1,927,445	46,855	$ 1,751,440
Matthew J. Meloy	12,096	639,153	14,998	560,625
Rene R. Joyce	62,705	3,313,332	69,431	2,595,331
James W. Whalen	35,677	1,885,173	43,871	1,639,898
Michael A. Heim	32,523	1,718,515	38,931	1,455,241

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

	December 10, 2010 Award (a)	February 14, 2011 Award (b)	January 12, 2012 Award (c)	Total
Joe Bob Perkins	27,192	4,250	5,035	36,477
Matthew J. Meloy	8,970	1,260	1,866	12,096
Rene R. Joyce	48,450	7,690	6,565	62,705
James W. Whalen	27,192	4,250	4,235	35,677
Michael A. Heim	24,354	3,770	4,399	32,523

(a) The restricted shares subject to the December 10, 2010 awards are subject to the following vesting schedule: 60% of the restricted shares vested on December 10, 2012 and the remaining 40% of the restricted shares will vest on December 10, 2013.

(b) 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.

(c) 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.

(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, 2012 ($52.84). The amounts do not include the related distribution equivalent rights for the award.

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

	December 3, 2009 Award (a)	August 2, 2010 Award (b)	February 17, 2011 Award (c)	January 12, 2012 Award (d)	Total
Joe Bob Perkins	13,860	--	16,705	16,290	46,855
Matthew J. Meloy	--	4,000	4,959	6,039	14,998
Rene R. Joyce	18,025	--	30,166	21,240	69,431
James W. Whalen	13,464	--	16,705	13,702	43,871
Michael A. Heim	9,894	--	14,804	14,233	38,931

(a) Reflects the target number of performance units granted to the named executive officers on December 3, 2009. Vesting of these awards is contingent upon continuous active employment at the end of the performance period, which ends June 30, 2013, 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 officer on August 2, 2010 . Vesting of this award is contingent upon continuous active employment at the end of the performance period, which ends June 30, 2013, 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 February 17, 2011 multiplied by a performance percentage of 142.9%. Vesting of these awards is contingent upon continuous active 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.

(d) Reflects the target number of performance units granted to the named executive officers on January 12, 2012 multiplied by a performance percentage of 100%. Vesting of these awards is contingent upon continuous active 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.

(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, 2012 ($37.38). The amounts do not include the related distribution equivalent rights for the award.

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Option Exercises and Stock Vested in 2012

The following table provides the amount realized during 2012 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 2012 year and, currently, there are no options outstanding under any of our plans.

	Stock Vested for 2012		Units Vested for 2012	
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	40,788	$ 1,952,929	20,800	$ 741,520
Matthew J. Meloy	13,455	644,225	7,500	267,375
Rene R. Joyce	72,675	3,479,679	34,000	1,212,100
James W. Whalen	40,788	1,952,929	-	-
Michael A. Heim	36,531	1,749,104	20,800	741,520

(1) Shares of restricted stock granted under our Stock Incentive Plan on December 10, 2010, which vested on December 10, 2012 (60% 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, 2012 vesting date ($47.88) and does not include associated dividends accrued during the vesting period.
(3) Performance units linked to the performance of the Partnership's common units granted under the Partnership's Long-Term Incentive Plan in January 2009 (in August 2009 with respect to Mr. Meloy), which vested on June 30, 2012, at the 100% payout level.
(4) Computed as the number of performance units vested multiplied by the closing price of a Partnership common unit on June 29, 2012 ($35.65), since the June 30, 2012 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 events and/or a change in control, in each case, that occurred on December 31, 2012. 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 2012 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	$ 3,716,541	$ 6,355,831	$ 2,108,018	$ 3,716,541
Matthew J. Meloy	1,214,345	2,499,134	675,198	1,214,345
Rene R. Joyce	5,921,379	9,316,935	3,124,135	5,921,379
James W. Whalen	3,556,379	6,183,936	1,973,111	3,556,379
Michael A. Heim	3,193,478	5,724,768	1,752,484	3,193,478

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Executive Officer Change in Control Severance Program

We adopted the Change in Control Program on and effective as of January 12, 2012. Each of our named executive officers became eligible to participate in the Change in Control Program during the 2012 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 Code for such individual, thereby subjecting the individual to an excise tax under section 4999 of the Code, then, depending on which method produces the largest net after-tax benefit for the recipient, the Payments shall either be: (i) reduced to the level at which no excise tax applies or (ii) paid in full, which would subject the individual to the excise tax.

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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, 2012.

Name	Qualifying Termination Following Change in Control (1)
Joe Bob Perkins	$ 2,639,290
Matthew J. Meloy	1,284,790
Rene R. Joyce	3,395,556
James W. Whalen	2,627,556
Michael A. Heim	2,531,290

(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, 2012 for each named executive officer and his eligible dependents in the following amounts: (a) Mr. Perkins – $47,290, (b) Mr. Meloy – $47,290, (c) Mr. Joyce – $35,556, (d) Mr. Whalen – $35,556, and (e) Mr. Heim – $47,290.

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, 2012. If a "Change in Control" occurs and the named executive officer has remained continuously employed by us from the date of grant to the date upon which such Change in Control occurs, then 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.

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

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

2. 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.

3. 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, 2012. The amounts reported below assume that the price per share of our common stock was $52.84, which was the closing price per share of our common stock on December 31, 2012.

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Name	Change in Control		Termination for Death or Disability	
Joe Bob Perkins	$ 2,007,139	(1)	$ 2,007,139	(1)
Matthew J. Meloy	665,309	(2)	665,309	(2)
Rene R. Joyce	3,453,614	(3)	3,453,614	(3)
James W. Whalen	1,964,214	(4)	1,964,214	(4)
Michael A. Heim	1,789,725	(5)	1,789,725	(5)

(1) Of the amount reported under each of the "Change in Control" column and the "Termination for Death or Disability" column: (a) $1,436,825 and $66,596, respectively, relate to the restricted shares and related dividend rights granted on December 10, 2010, which are scheduled to vest December 10, 2013; (b) $224,570 and $8,989, respectively, relate to the restricted shares and related dividend rights granted on February 14, 2011, which are scheduled to vest February 14, 2014; and (c) $266,049 and $4,110, respectively, relate to the restricted shares and related dividend rights granted on January 12, 2012, which are scheduled to vest on January 12, 2015.

(2) Of the amount reported under each of the "Change in Control" column and the "Termination for Death or Disability" column: (a) $473,975 and $21,968, respectively, relate to the restricted shares and related dividend rights granted on December 10, 2010, which are scheduled to vest December 10, 2013; (b) $66,578 and $2,665, respectively, relate to the restricted shares and related dividend rights granted on February 14, 2011, which are scheduled to vest February 14, 2014; and (c) $98,599 and $1,523, respectively, relate to the restricted shares and related dividend rights granted on January 12, 2012, which are scheduled to vest on January 12, 2015.

(3) Of the amount reported under each of the "Change in Control" column and the "Termination for Death or Disability" column: (a) $2,560,098 and $118,659, respectively, relate to the restricted shares and related dividend rights granted on December 10, 2010, which are scheduled to vest December 10, 2013; (b) $406,340 and $16,264, respectively, relate to the restricted shares and related dividend rights granted on February 14, 2011, which are scheduled to vest February 14, 2014; and (c) $346,895 and $5,359, respectively, relate to the restricted shares and related dividend rights granted on January 12, 2012, which are scheduled to vest on January 12, 2015.

(4) Of the amount reported under each of the "Change in Control" column and the "Termination for Death or Disability" column: (a) $1,436,825 and $66,596, respectively, relate to the restricted shares and related dividend rights granted on December 10, 2010, which are scheduled to vest December 10, 2013; (b) $224,570 and $8,989, respectively, relate to the restricted shares and related dividend rights granted on February 14, 2011, which are scheduled to vest February 14, 2014; and (c) $223,777 and $3,457, respectively, relate to the restricted shares and related dividend rights granted on January 12, 2012, which are scheduled to vest on January 12, 2015.

(5) Of the amount reported under each of the "Change in Control" column and the "Termination for Death or Disability" column: (a) $1,286,865 and $59,645, respectively, relate to the restricted shares and related dividend rights granted on December 10, 2010, which are scheduled to vest December 10, 2013; (b) $199,207 and $7,974, respectively, relate to the restricted shares and related dividend rights granted on February 14, 2011, which are scheduled to vest February 14, 2014; and (c) $232,443 and $3,591, respectively, relate to the restricted shares and related dividend rights granted on January 12, 2012, which are scheduled to vest on January 12, 2015.

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, 2012. If a "Change in Control" occurs during the performance period established for the performance units and related distribution equivalent rights granted to a named executive officer under the Performance Unit Agreements prior to 2011, the performance units and related distribution equivalent rights then credited to a named executive officer will be cancelled and the named executive officer will be paid an amount in cash equal to the sum of (i) the product of (a) the fair market value of a common unit of the Partnership multiplied by (b) the target number of performance units granted to the named executive officer, plus (ii) the amount of distribution equivalent rights then credited to the named executive officer, if any. 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 in 2011 and later years, 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," 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.

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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 or their employment was terminated due to death or Disability or by us without Cause, each as of December 31, 2012. The amounts reported below assume that the price per Partnership common unit was $37.38, which was the closing price per common unit on December 31, 2012. 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, 2012 and are based on achieving the next higher performance level for the award (if any) that exceeds performance for the 2012 fiscal year.

Name	Change in Control		Termination for Death or Disability or Without Cause	
Joe Bob Perkins	$ 1,709,402	(1)	$ 2,108,018	(1)
Matthew J. Meloy	549,036	(2)	675,198	(2)
Rene R. Joyce	2,467,765	(3)	3,124,135	(3)
James W. Whalen	1,592,165	(4)	1,973,111	(4)
Michael A. Heim	1,403,753	(5)	1,752,484	(5)

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(1) Of the amount reported under the "Change in Control" column; (a) $518,087 and $81,116, respectively, relate to the performance units and related distribution equivalent rights granted on December 3, 2009; (b) $436,972 and $43,048, respectively, relate to the performance units and related distribution equivalent rights granted on February 17, 2011; and (c) $608,920 and $21,258, respectively, relate to the performance units and related distribution equivalent rights granted on January 12, 2012. Of the amount reported under the "Termination for Death or Disability or Without Cause" column: (a) $518,087 and $99,840, respectively, relate to the performance units and related distribution equivalent rights granted on December 3, 2009; (b) $624,433 and $127,919, respectively, relate to the performance units and related distribution equivalent rights granted on February 17, 2011; and (c) $608,920 and $129,180, respectively, relate to the performance units and related distribution equivalent rights granted on

January 12, 2012.

(2) Of the amount reported under the “Change in Control” column: (a) $149,520 and $23,410, respectively, relate to the performance units and related distribution equivalent rights granted on August 2, 2010; (b) $129,709 and $12,778, respectively, relate to the performance units and related distribution equivalent rights granted on February 17, 2011; and (c) $225,738 and $7,881, respectively, relate to the performance units and related distribution equivalent rights granted on January 12, 2012. Of the amount reported under the “Termination for Death or Disability or Without Cause” column: (a) $149,520 and $28,710, respectively, relate to the performance units and related distribution equivalent rights granted on December 3, 2009; (b) $185,367 and $37,974, respectively, relate to the performance units and related distribution equivalent rights granted on February 17, 2011; and (c) $225,738 and $47,889, respectively, relate to the performance units and related distribution equivalent rights granted on January 12, 2012.

(3) Of the amount reported under the “Change in Control” column: (a) $673,775 and $105,491, respectively, relate to the performance units and related distribution equivalent rights granted on December 3, 2009; (b) $789,092 and $77,738, respectively, relate to the performance units and related distribution equivalent rights granted on February 17, 2011; and (c) $793,951 and $27,718, respectively, relate to the performance units and related distribution equivalent rights granted on January 12, 2012. Of the amount reported under the “Termination for Death or Disability or Without Cause” column: (a) $673,775 and $129,374, respectively, relate to the performance units and related distribution equivalent rights granted on December 3, 2009; (b) $1,127,605 and $230,996, respectively, relate to the performance units and related distribution equivalent rights granted on February 17, 2011; and (c) $793,951 and $168,433, respectively, relate to the performance units and related distribution equivalent rights granted on January 12, 2012.

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(4) Of the amount reported under the "Change in Control" column: (a) $503,284 and $78,798, respectively, relate to the performance units and related distribution equivalent rights granted on December 3, 2009; (b) $436,972 and $43,048, respectively, relate to the performance units and related distribution equivalent rights granted on February 17, 2011; and (c) $512,181 and $17,881, respectively, relate to the performance units and related distribution equivalent rights granted on January 12, 2012. Of the amount reported under the "Termination for Death or Disability or Without Cause" column: (a) $503,284 and $96,638, respectively, relate to the performance units and related distribution equivalent rights granted on December 3, 2009; (b) $624,433 and $127,919, respectively, relate to the performance units and related distribution equivalent rights granted on February 17, 2011; and (c) $512,181 and $108,657, respectively, relate to the performance units and related distribution equivalent rights granted on January 12, 2012.

(5) Of the amount reported under the "Change in Control" column: (a) $369,838 and $57,905, respectively, relate to the performance units and related distribution equivalent rights granted on December 3, 2009; (b) $387,257 and $38,151, respectively, relate to the performance units and related distribution equivalent rights granted on February 17, 2011; and (c) $532,030 and $18,574, respectively, relate to the performance units and related distribution equivalent rights granted on January 12, 2012. Of the amount reported under the "Termination for Death or Disability or Without Cause" column: (a) $369,838 and $71,014, respectively, relate to the performance units and related distribution equivalent rights granted on December 3, 2009; (b) $553,374 and $113,362, respectively, relate to the performance units and related distribution equivalent rights granted on February 17, 2011; and (c) $532,030 and $112,868, respectively, relate to the performance units and related distribution equivalent rights granted on January 12, 2012.

Director Compensation

The following table sets forth the compensation earned by our non-employee directors for 2012:

Name	Fees Earned or Paid in Cash	Stock Awards $ (3)	Total Compensation
Charles R. Crisp (2)	$ 96,500	$ 73,735	$ 170,235
Ershel C. Redd Jr.	75,500	73,735	149,235
Chris Tong (2)	94,000	73,735	167,735
Peter R. Kagan (1)(2)	85,500	73,735	159,235
In Seon Hwang (1)	72,500	73,735	146,235

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(1) Each of Messrs. Kagan and Hwang earned $63,550 and $65,000, respectively, in fees for service on the Board of Directors of the general partner in 2012. Mr. Kagan's compensation included $63,500 in cash fees, $77,285 in common unit awards and $82,562 in all other compensation. Mr. Hwang's compensation included $65,500 in cash fees, $77,285 in common unit awards and $0 in all other compensation. Please see "Director Compensation" in the Partnership's Annual Report on Form 10-K for the fiscal year ended December 31, 2012 for additional information.

(2) As of December 31, 2012, Messrs. Crisp, Tong, and Kagan each held 750 unvested common units of the Partnership.

(3) Amounts reported in the "Stock Awards" column represent the aggregate grant date fair value of fully vested shares of our common stock awarded to the non-employee directors under our Stock Incentive Plan, computed in accordance with FASB ASC Topic 718. For a discussion of the assumptions and methodologies used to value the awards reported in this column, see the discussion contained in the Notes to Consolidated Financial Statements at Note 22 included in our Annual Report on Form 10-K for the year ended December 31, 2012. On January 12, 2012, each director received 1,851 fully vested shares of our common stock in connection with their 2012 service on our Board of Directors, and the grant date fair value of each share of common stock computed in accordance

with FASB ASC Topic 718 was $38.72. As of December 31, 2012, none of our non-employee directors held any outstanding stock options or any outstanding, unvested shares of our common stock.

Narrative to Director Compensation Table

For 2012, all non-employee directors received an annual cash retainer of $50,000. The Chairman of the Audit Committee received an additional annual retainer of $20,000, the Chairman of the Compensation Committee received an additional annual retainer of $15,000 and the Chairman of the Governing and Nominating Committee received an additional retainer of $10,000. All of our non-employee directors receive $1,500 for each Board of Directors, Audit Committee, Compensation Committee, Governance and Nominating Committee, and Conflicts Committee meeting attended. Payment of non-employee director fees is generally made twice annually, at the second regularly scheduled meeting of the Board of Directors and at the final regularly scheduled meeting of the Board of Directors for the fiscal year. All non-employee directors are reimbursed for out-of-pocket expenses incurred in attending Board of Director and committee meetings.

A director who is also an employee receives no additional compensation for services as a director. Accordingly, the Summary Compensation Table reflects total compensation received by Messrs. Joyce, Perkins and Whalen for services performed for us and our affiliates.

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Director Long-term Equity Incentives

We granted equity awards in January 2012 to our non-employee directors under the Stock Incentive Plan. Each of these directors received an award of 1,851 fully vested shares of our common stock, which reflected our intent to provide them with a target value of approximately $75,000 in annual long-term incentive awards. The awards are intended to align the long-term interests of our directors with those of our stockholders.

Changes for 2013

In January 2013, the Board of Directors approved changes to our non-employee director compensation for the 2013 fiscal year by increasing the annual cash retainer for service on our Board of Directors to $56,000 per year.

Director Long-term Equity Incentives. In January 2013, each of our non-employee directors received an award of 1,492 fully vested shares of our common stock under the Stock Incentive Plan, which reflects our desire to increase the target value of those awards from approximately $75,000 to $80,000 per year.

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

The following table sets forth information regarding the beneficial ownership of our common stock and the beneficial ownership of the Partnership's common units as of February 15, 2013 held by:

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

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 stockholders and unitholders identified in the table below have sole voting and investment power with respect to all securities shown as beneficially owned by them. Percentage ownership calculations for any security holder listed in the table below are based on 42,331,085 shares of our common stock and 101,788,617 common units of the Partnership outstanding on February 15, 2013.

	Targa Resources Partners LP		Targa Resources Corp.	
Name of Beneficial Owner (1)	Common Units Beneficially Owned (9)	Percentage of Common Units Beneficially Owned (9)	Common Stock Beneficially Owned	Percentage of Common Stock Beneficially Owned
Warburg Pincus Private Equity VIII, L.P. (2)	-	-	2,941,917	6.9%
Warburg Pincus Netherlands Private Equity VIII C.V.I (2)	-	-	85,273	*
WP-WPVIII Investors, L.P. (2)	-	-	8,534	*
Warburg Pincus Private Equity IX, L.P. (2)	-	-	1,672,580	4.0%
Prudential Financial, Inc. (3)	-	-	4,439,865	10.5%
BAMCO Inc	-	-	2,495,443	5.9%
Fidelity Management and Research Company	-	-	2,230,919	5.3%
Rene R. Joyce (4)	81,000	*	1,107,631	2.6%
Joe Bob Perkins (5)	32,100	*	624,988	1.5%
Michael A. Heim (6)	8,000	*	605,932	1.4%
James W. Whalen (7)	111,152	*	645,114	1.5%
Matthew J Meloy	6,000	*	72,263	*
In Seon Hwang (8)	6,246	*	4,719,966	11.2%
Peter R. Kagan (8)	16,496	*	4,729,778	11.2%
Chris Tong	23,150	*	61,592	*
Charles R. Crisp	11,350	*	152,933	*
Ershel C. Redd Jr.	1,100	*	5,853	*
All directors and executive officers as a group (14 persons) (7)	396,012	*	9,428,689	22.3%

* Less than 1%.

(1) Unless otherwise indicated, the address for all beneficial owners in this table is 1000 Louisiana, Suite 4300, Houston, Texas 77002.

(2) Warburg Pincus Private Equity VIII, L.P., a Delaware limited partnership, and two affiliated partnerships, Warburg Pincus Netherlands Private Equity VIII C.V.I., a company organized under the laws of the Netherlands, and WP-WP VIII Investors, L.P., a Delaware limited partnership (together "WP VIII"), and Warburg Pincus Private Equity IX, L.P., a Delaware limited partnership ("WP IX"), in the aggregate own, on a fully diluted basis, approximately 11% of our equity interests. The general partner of WP VIII is Warburg Pincus Partners, LLC, a New York limited liability company ("WP Partners LLC"), and the general partner of WP IX is Warburg Pincus IX, LLC, a New York limited liability company, of which WP Partners LLC is the sole member. Warburg Pincus & Co., a New York general partnership ("WP"), is the managing member of WP Partners LLC. WP VIII and WP IX are managed by Warburg Pincus LLC, a New York limited liability company ("WP LLC"). The address of the Warburg Pincus entities is 450 Lexington Avenue, New York, New York 10017. Messrs. Hwang and Kagan are Partners of WP and Managing Directors and Members of WP LLC. Charles R. Kaye and Joseph P. Landy are Managing General Partners of WP and Managing Members and Co-Presidents of WP LLC and may be deemed to control the Warburg Pincus entities. Messrs. Hwang, Kagan, Kaye and Landy disclaim beneficial ownership of all shares held by the Warburg Pincus entities.

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(3) The business address for Prudential Financial, Inc. is 751 Broad Street, Newark, New Jersey 07102-3777. Prudential Financial, Inc. through its indirect ownership of The Prudential Insurance Company of America ("PICOA") may be deemed to presently hold 17,100 shares of our common stock for the benefit of PICOA's general account. Prudential Financial, Inc. may be deemed the beneficial owner of securities beneficially owned by PICOA, Jennison Associates LLC, Prudential Investment Management, Inc. and Quantitative Management Associates LLC and may have direct or indirect voting and/or investment discretion over 4,422,765 shares which are held for its own benefit or for the benefit of its clients by its separate accounts, externally managed accounts, registered investment companies, subsidiaries and/or other affiliates. Of the 4,439,865 common shares reported as beneficially held by Prudential Financial, Inc., Prudential Financial, Inc. has reported that it has shared voting power with respect to 133,991 of these common shares and shared dispositive power with respect to 4,305,874 of the common shares.

(4) Shares of common stock beneficially owned by Mr. Joyce include: (i) 234,959 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.

(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.

(8) All shares indicated as owned by Messrs. Hwang and Kagan other than 11,662 shares issued to Mr. Hwang and 21,474 shares issued to Mr. Kagan in their capacity as directors are included because of their affiliation with the Warburg Pincus entities.

(9) The common units of the Partnership presented as being beneficially owned by our directors and officers do not include the common units held indirectly by us that may be attributable to such directors and officers based on their ownership of equity interests in us.

Securities Authorized for Issuance under Equity Compensation Plans

The following table sets forth certain information as of December 31, 2012 regarding our long-term incentive plans, under which our common stock is authorized for issuance to employees, consultants and directors of us, our general partner and its affiliates. Our sole equity compensation plan, under which we will make equity grants in the future, is our long-term incentive plan, which was approved by our stockholders prior to our initial public offering.

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding

	(a)	(b)	securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	-	-	3,091,332(1)
Equity compensation plans not approved by security holders	-	-	-
Total	-	-	3,091,332

(1) Generally, awards of restricted stock to our officers and employees under the 2010 Incentive Plan are subject to vesting over time as determined by the Compensation Committee and, prior to vesting, are subject to forfeiture. Stock incentive plan awards may vest in other circumstances, as approved by the Compensation Committee and reflected in an award agreement. Restricted stock is issued, subject to vesting, on the date of grant. The Compensation Committee may provide that dividends on restricted stock are subject to vesting and forfeiture provisions, in which cash such dividends would be held, without interest, until they vest or are forfeited.

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

Our Relationship with Targa Resources Partners LP and its General Partner

Our only cash generating assets consist of our interests in the Partnership, which as of February 15, 2013 consists of the following:

- a 2.0% general partner interest in the Partnership, which we hold through our 100% ownership interests in the general partner;
- all of the outstanding IDRs of the Partnership; and
- 12,945,659 of the 101,788,617 outstanding common units of the Partnership, representing a 12.7% limited partnership interest.

Omnibus Agreement

Our Omnibus Agreement with the Partnership addresses the reimbursement to us for costs we incur on the Partnership's behalf, competition and indemnification matters. Any or all of the provisions of the Omnibus Agreement, other than the indemnification provisions described below, are terminable by us at our option if the general partner is removed as the Partnership's general partner without cause and units held by us and our affiliates have not voted in favor of that removal. The Omnibus Agreement will also terminate in the event of a Change of Control (as defined in the Omnibus Agreement) of the Partnership or its general partner. The Omnibus Agreement expires according to its terms on April 30, 2013, and the Omnibus Agreement will not be extended. At such time, reimbursement matters will be governed by our partnership agreement, which provides that our general partner will be 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 the Omnibus Agreement, the Partnership reimburses us for the payment of certain operating and direct expenses, including compensation and benefits of operating personnel, and for the provision of various general and administrative services for the Partnership's benefit. Pursuant to these arrangements, we perform centralized corporate functions for the Partnership, such as legal, accounting, treasury, insurance, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes, engineering and marketing. The Partnership reimburses us for the direct expenses to provide these services as well as other direct expenses we incur on the Partnership's behalf, such as compensation of operational personnel performing services for the Partnership's benefit and the cost of their employee benefits, including 401(k), pension and health insurance benefits. The general partner determines the amount of general and administrative expenses to be allocated to the Partnership in accordance with the partnership agreement. Other than our direct costs of being a reporting company, so long as our only cash-generating asset consists of our interests in the Partnership, substantially all of our general and administrative costs have been, so long as our only cash-generating assets consist of our interest in the Partnership, and will continue to be allocated to the Partnership. The Omnibus Agreement expires according to its terms on April 30, 2013, and the term of the Omnibus Agreement will not be extended. At such time, reimbursement matters will be governed by the Partnership Agreement, which provides that we will be reimbursed for all direct and indirect expenses, as well as expenses otherwise allocable to the Partnership in connection with the operation of the Partnership's business, incurred on the Partnership's behalf.

Competition

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

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Registration Rights Agreement

Agreement with Series B Preferred Stock Investors

On October 31, 2005, we entered into an amended and restated registration rights agreement with the holders of our then outstanding Series B preferred stock that received or purchased 6,453,406 shares of preferred stock pursuant to a stock purchase agreement dated October 31, 2005. Pursuant to the registration rights agreement, we agreed to register the sale of shares of our common stock that holders of such preferred stock received upon conversion of the preferred stock, under certain circumstances. These holders include (directly or indirectly through subsidiaries or affiliates), among others, Warburg Pincus.

Demand Registration Rights

At any time, the qualified holders have the right to require us by written notice to register a specified number of shares of common stock in accordance with the Securities Act and the registration rights agreement. The qualified holders have the right to request up to an aggregate of five registrations; provided that such qualified holders are not limited in the number of demand registrations that constitute "shelf" registrations pursuant to Rule 415 under the Securities Act. In no event shall more than one demand registration occur during any six-month period or within 120 days after the effective date of a registration statement we file, provided that no demand registration may be prohibited for that 120-day period more than once in any 12-month period.

Piggy-back Registration Rights

If, at any time, we propose to file a registration statement under the Securities Act with respect to an offering of common stock (subject to certain exceptions), for our own account, then we must give at least 15 days' notice prior to the anticipated filing date to all holders of registrable securities to allow them to include a specified number of their shares in that registration statement. We will be required to maintain the effectiveness of that registration statement until the earlier of 180 days after the effective date and the consummation of the distribution by the participating holders.

Conditions and Limitations; Expenses

These registration rights are subject to certain conditions and limitations, including the right of the underwriters to limit the number of shares to be included in a registration and our right to delay or withdraw a registration statement under certain circumstances. We will generally pay all registration expenses in connection with our obligations under the registration rights agreement, regardless of whether a registration statement is filed or becomes effective.

Contracts with Affiliates

Indemnification Agreements with Directors and Officers

In February 2007, the Partnership and the general partner entered into indemnification agreements with each independent director of the general partner. Each indemnification agreement provides that each of the Partnership and the general partner will indemnify and hold harmless each indemnitee against Expenses (as defined in the indemnification agreement) to the fullest extent permitted or authorized by law, including the Delaware Revised Uniform Limited Partnership Act and the Delaware Limited Liability Company Act in effect on the date of the agreement or as such laws may be amended to provide more advantageous rights to the indemnitee. If such indemnification is unavailable as a result of a court decision and if the Partnership or the general partner is jointly liable in the proceeding with the indemnitee, the Partnership and the general partner will contribute funds to the indemnitee for his Expenses (as defined in the in the Indemnification Agreement) in proportion to relative benefit and fault of the Partnership or the general partner on the one hand and indemnitee on the other in the transaction giving rise to the proceeding.

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

We have entered into parent indemnification agreements with each of our directors and officers, including Messrs. Joyce, Perkins, Whalen, Kagan, Meloy and Hwang who serve or served as directors and/or officers of the general partner. Each parent indemnification agreement provides that we will indemnify and hold harmless each indemnitee for Expenses (as defined in the parent indemnification agreement) to the fullest extent permitted or authorized by law, including the Delaware General Corporation Law, in effect on the date of the agreement or as it may be amended to provide more advantageous rights to the indemnitee. If such indemnification is unavailable as a result of a court decision and if we and the indemnitee are jointly liable in the proceeding, we will contribute funds to the indemnitee for his Expenses in proportion to relative benefit and fault of us and indemnitee in the transaction giving rise to the proceeding.

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

Indemnification Agreements with the Partnership

Under the Omnibus Agreement, the Partnership agreed to indemnify us against environmental liabilities related to the North Texas System arising or occurring after February 14, 2007.

Additionally, we have agreed to indemnify the Partnership 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. We do not have any obligation under this indemnification until the Partnership's aggregate losses exceed $250,000. Our obligation under this indemnification will terminate upon the expiration of any applicable statute of limitations. The Partnership will indemnify us for all losses attributable to the post-IPO operations of the North Texas System.

Transactions with Related Persons

Relationship with Sajet Resources LLC

Former holders of our Class B Common units, including Warburg Pincus and 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. We provide general and administrative services to Sajet and are reimbursed for these amounts at our actual cost. During 2012, we were reimbursed $1.3 million for such services provided. Additionally, on December 1, 2012, Targa Midstream Services LLC purchased six 90,000 gallon propane storage tanks from Sajet for $1.2 million. This transaction was at a market price consistent with similar transactions with other nonaffiliated entities.

Relationship with Tesla Resources LLC

In September 2012, Tesla Resources LLC ("Tesla") was spun-off from Sajet. Tesla owns certain technology rights, real property and ownership interests in Floridian Natural Gas Storage Company LLC. We will provide general and administrative services to Tesla and will be reimbursed for these amounts at our actual cost. During 2012, there were no services rendered.

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Relationship with Warburg Pincus LLC

Affiliates of Warburg Pincus beneficially own approximately 11.1% of our outstanding common stock. Accordingly, Warburg Pincus can exert significant influence over us and any action requiring the approval of the holders of our stock, including the election of directors and approval of significant corporate transactions. Warburg's concentrated ownership makes it less likely that any other holder or group of holders of common stock will be able to affect the way we are managed or the direction of our business.

Peter Kagan, one of our directors, is a Managing Director of Warburg Pincus LLC and is also a director of Laredo Petroleum Holdings Inc. ("Laredo") from whom the Partnership buys natural gas and NGL products. Affiliates of Warburg Pincus LLC own a controlling interest in Laredo. Purchases from Laredo during 2012 totaled $88.1 million. These transactions were at market prices consistent with similar transactions with other nonaffiliated entities.

Relationship with Total Safety US Inc.

Joe Bob Perkins, our Chief Executive Officer, is also a member of the Board of Managers of W3 Holdings, LLC, parent company of Total Safety US Inc. ("Total Safety") which provides the Partnership safety services and equipment, including detection and monitoring systems. Affiliates of Warburg Pincus own a controlling interest in Total Safety. During 2012, we made payments of $242,980 to Total Safety. These transactions were at market prices consistent with similar transactions with other nonaffiliated entities.

Relationships with Sequent Energy Management, LP, EOG Resources Inc. and IntercontinentalExchange, Inc.

Charles R. Crisp, one of our directors, is a director of AGL Resources, Inc., parent company of Sequent Energy Management, LP ("Sequent") and Northern Illinois Gas Company d/b/a NICOR Energy ("NICOR"). The Partnership purchases and sells natural gas and NGL products from and to Sequent and sells natural gas products to NICOR. Mr. Crisp also serves as a director of EOG Resources Inc. ("EOG") from whom the Partnership purchases natural gas and NGL products. Mr. Crisp is also a director of IntercontinentalExchange Inc., parent company of ICE US OTC Commodity Markets LLC ("ICE") from whom the Partnership purchases brokerage services. The following table shows the Partnership's transactions with each of these entities during 2012.

	Sales	Purchases
	(In millions)	
Sequent	$ 20.8	$ 4.5
EOG	-	8.4
ICE	-	0.1
NICOR	19.0	-

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

Relationships with Martin Gas Sales and Southwest Energy LP

Erschel C. Redd, one of our directors, has an immediate family member who is an officer of Martin Gas Sales, which is a subsidiary of Martin Midstream Partners LP ("Martin") and an immediate family member who is an officer and part owner of Southwest Energy LP ("Southwest Energy") from and to whom the Partnership purchases and sells natural gas and NGL products. The following table shows the Partnership's transactions with each of these entities during 2012.

	Sales	Purchases
	(In millions)	

Martin Gas	$ 7.3	$ 7.1
Southwest Energy	3.4	1.8

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

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Conflicts of Interest

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

Review, Approval or Ratification of Transactions with Related Persons

Our policies and procedures for approval or ratification of transactions with "related persons" are not contained in a single policy or procedure. Instead, they are reflected in the general operation of our board of directors, consistent with past practice. Prior to our IPO, an agreement among our stockholders prohibited us from entering into, modifying, amending or terminating any transaction (other than certain compensatory arrangements and sales or purchases of capital stock) with an executive officer, director or affiliate without the prior written consent of the holders of at least a majority of our outstanding shares. We distribute and review a questionnaire to our executive officers and directors requesting information regarding, among other things, certain transactions with us in which they or their family members have an interest. If a conflict or potential conflict of interest arises between us and our affiliates (excluding the Partnership) on the one hand and the Partnership and its limited partners (other than us and our affiliates), on the other hand, the resolution of any such conflict or potential conflict is addressed as described under "—Conflicts of Interest." Pursuant to our Code of Conduct, our officers and directors are required to abandon or forfeit any activity or interest that creates a conflict of interest between them and us or any of our subsidiaries, unless the conflict is pre-approved by our board of directors.

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

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

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

- approved by the vote of a majority of the Partnership's outstanding common units, excluding any common units owned by the general partner or any of its affiliates;

- on terms no less favorable to the Partnership than those generally being provided to or available from unrelated third parties; or

- fair and reasonable to the Partnership, taking into account the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to the Partnership.

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

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Director Independence

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

Item 14. Principal Accounting Fees and Services.

We have engaged PricewaterhouseCoopers LLP as our principal accountant. The following table summarizes fees we were billed by PricewaterhouseCoopers LLP for independent auditing, tax and related services for each of the last two fiscal years:

	2012	2011
	(In millions)	
Audit fees (1)	$ 3.1	$ 2.7
Audit related fees (2)	-	-
Tax fees (3)	-	-
All other fees (4)	-	-
	$ 3.1	$ 2.7

(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.

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

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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 Financial Statements" Page F-1 of this Annual Report.

(a)(2) Financial Statement Schedules

All other 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)).
3.1	Amended and Restated Certificate of Incorporation of Targa Resources Corp. (incorporated by reference to Exhibit 3.1 to Targa Resources Corp.'s Current Report on Form 8-K filed December 16, 2010 (File No. 001-34991)).
3.2	Form of Amended and Restated Bylaws of Targa Resources Corp. (incorporated by reference to Exhibit 3.1 to Targa Resources Corp.'s Current Report on Form 8-K filed December 16, 2010 (File No. 001-34991)).
3.3	

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)).

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3.4 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)).

3.5 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)).

3.6 Amendment No. 1 to First Amended and Restated Agreement of Limited Partnership of Targa Resources Partners LP (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)).

3.7 Amendment No. 2 to the 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)).

3.8 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)).

3.9 Amended and Restated Certificate of Incorporation of Targa Resources, Inc. (incorporated by reference to Exhibit 3.1 to Targa Resources, Inc.'s Registration Statement on Form S-4 filed October 31, 2007 (File No. 333-147066)).

3.10 Amendment to Amended and Restated Certificate of Incorporation of Targa Resources, Inc. (incorporated by reference to Exhibit 3.9 of Targa Resources Corp.'s Annual Report on Form 10-K filed February 28, 2011 (File No. 001-34991)).

3.11 Amended and Restated Bylaws of Targa Resources, Inc. (incorporated by reference to Exhibit 3.2 to Targa Resources, Inc.'s Registration Statement on Form S-4 filed October 31, 2007 (File No. 333-147066)).

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

10.1 Credit Agreement, dated as of January 5, 2010 among Targa Resources, Inc., as the borrower, Deutsche Bank Trust Company Americas, as the administrative agent, Deutsche Bank Securities Inc. and Credit Suisse Securities (USA) LLC, as joint lead arrangers, Credit Suisse Securities (USA) LLC and Citadel Securities LLC, as the co-syndication agents, Deutsche Bank Securities Inc., Credit Suisse Securities (USA) LLC, Citadel Securities LLC, Banc of America Securities LLC and Barclays Capital, as joint book runners, Bank of America, N.A., Barclays Bank PLC and ING Capital LLC, as the co-documentation agents and the other lenders party thereto (incorporated by reference to Exhibit 4.1 to Targa Resources Corp.'s Registration Statement on Form S-1/A filed November 12, 2010 (File No. 333-169277)).

10.2 Amendment No. 1 to Credit Agreement, dated November 12, 2010 among TRI Resources Inc., as the Borrower, Deutsche Bank Trust Company Americas, Credit Suisse AG, Cayman Islands Branch, Bank of America, N.A., ING Capital LLC and Barclays Bank PLC, as Lenders, and Deutsche Bank Trust Company Americas, as Administrative Agent (incorporated by reference to Exhibit 10.94 to Targa Resources Corp.'s Registration Statement on Form S-1/A filed November 16, 2010 (File No. 333-169277)).

10.3 Holdco Credit Agreement, dated as of August 9, 2007 among Targa Resources Investments Inc., as the borrower, Credit Suisse, as the administrative agent, Credit Suisse Securities (USA) LLC and Deutsche Bank Securities Inc.

and, as joint lead arrangers, Deutsche Bank Securities Inc., as the syndication agent, Credit Suisse Securities (USA) LLC, Deutsche Bank Securities Inc., Lehman Brothers, Inc. and Merrill Lynch Capital Corporation, as joint book runners, Lehman Commercial Paper Inc. and Merrill Lynch Capital Corporation, as the co-documentation agents and the other lenders party thereto (incorporated by reference to Exhibit 4.1 to Targa Resources Corp.'s Registration Statement on Form S-1/A filed November 12, 2010 (File No. 333-169277)).

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10.4	Amendment No. 1 to Holdco Credit Agreement, dated January 5, 2010 among Targa Resources Investments Inc., as the Borrower, Targa Resources, Inc., as Lender, Targa Capital, LLC, as Lender, and Credit Suisse AG, Cayman Islands Brach, as Administrative Agent (incorporated by reference to Exhibit 10.92 to Targa Resources Corp.'s Registration Statement on Form S-1/A filed November 12, 2010 (File No. 333-169277)).
10.5	Amended and Restated Credit Agreement, dated July 19, 2010, by and among Targa Resources Partners LP, as the borrower, Bank of America, N.A., as the administrative agent, Wells Fargo Bank, National Association and the Royal Bank of Scotland plc, as the co-syndication agents, Deutsche Bank Securities Inc. and Barclays Bank PLC, as the co-documentation agents, Banc of America Securities LLC, Wells Fargo Securities, LLC and RBS Securities Inc., as joint lead arrangers and co-book managers and the other lenders part thereto (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Form 8-K filed on July 21, 2010 (File No. 001-33303)).
10.6	Credit Agreement, dated October 3, 2012, by and among Targa Resources Corp., Deutsche Bank Trust Company Americas, as Administrative Agent, Collateral Agent, Swing Line Lender and the L/C Issuer and each lender from time to time party thereto (incorporated by reference to Exhibit 10.1 to Targa Resources Corp.'s Current Report on Form 8-K filed October 9, 2012 (File No. 001-34991)).
10.7	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)).
10.8	Targa Resources Investments Inc. Amended and Restated Stockholders' Agreement dated as of October 28, 2005 (incorporated by reference to Exhibit 10.2 to Targa Resources Inc.'s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.9	First Amendment to Amended and Restated Stockholders' Agreement, dated January 26, 2006 (incorporated by reference to Exhibit 10.3 to Targa Resources Inc.'s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.10	Second Amendment to Amended and Restated Stockholders' Agreement, dated March 30, 2007 (incorporated by reference to Exhibit 10.4 to Targa Resources Inc.'s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.11	Third Amendment to Amended and Restated Stockholders' Agreement, dated May 1, 2007 (incorporated by reference to Exhibit 10.5 to Targa Resources Inc.'s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.12	Fourth Amendment to Amended and Restated Stockholders' Agreement, dated December 7, 2007 (incorporated by reference to Exhibit 10.6 to Targa Resources Inc.'s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.13	Fifth Amendment to Amended and Restated Stockholders' Agreement, dated December 1, 2009 (incorporated by reference to Exhibit 10.1 to Targa Resources, Inc.'s Current Report on Form 8-K filed December 2, 2009 (File No. 333-147066)).
10.14	Form of Sixth Amendment to Amended and Restated Stockholders' Agreement (incorporated by reference to Exhibit 10.11 to Targa Resources Corp.'s Registration Statement on Form S-1/A filed November 12, 2010 (File No. 333-169277)).

10.15+	Targa Resources Investments Inc. 2005 Stock Incentive Plan (incorporated by reference to Exhibit 10.10 to Targa Resources Inc.'s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.16+	First Amendment to Targa Resources Investments Inc. 2005 Stock Incentive Plan (incorporated by reference to Exhibit 10.11 to Targa Resources Inc.'s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).

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10.17+	Second Amendment to Targa Resources Investments Inc. 2005 Stock Incentive Plan (incorporated by reference to Exhibit 10.12 to Targa Resources Inc.'s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.18+	Form of Targa Resources Investments Inc. Nonstatutory Stock Option Agreement (Non-Employee Directors) (incorporated by reference to Exhibit 10.13 to Targa Resources Inc.'s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.19+	Form of Targa Resources Investments Inc. Nonstatutory Stock Option Agreement (Non-Director Management and Other Employees) (incorporated by reference to Exhibit 10.14 to Targa Resources Inc.'s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.20+	Form of Targa Resources Investments Inc. Incentive Stock Option Agreement (incorporated by reference to Exhibit 10.15 to Targa Resources Inc.'s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.21+	Form of Targa Resources Investments Inc. Restricted Stock Agreement (incorporated by reference to Exhibit 10.16 to Targa Resources Inc.'s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.22+	Form of Targa Resources Investments Inc. Restricted Stock Agreement (relating to preferred stock option exchange for directors) (incorporated by reference to Exhibit 10.17 to Targa Resources Inc.'s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.23+	Form of Targa Resources Investments Inc. Restricted Stock Agreement (relating to preferred stock option exchange for employees) (incorporated by reference to Exhibit 10.18 to Targa Resources Inc.'s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.24+	Targa Resources Corp. 2010 Stock Incentive Plan (incorporated by reference to Exhibit 4.3 of Targa Resources Corp.'s Registration Statement on Form S-8 filed December 9, 2010 (File No. 333-171082)).
10.25+	Form of Targa Resources Corp. Restricted Stock Agreement – 2010 (incorporated by reference to Exhibit 4.4 of Targa Resources Corp.'s Registration Statement on Form S-8 filed December 9, 2010 (File No. 333-171082)).
10.26+	Form of Targa Resources Corp. 2011 Restricted Stock Agreement – 2011 (incorporated by reference to Exhibit 10.2 of Targa Resources Corp.'s Current Report on Form 8-K filed February 18, 2011 (File No. 001-34991)).
10.27+	Targa Resources Investments Inc. Long-Term Incentive Plan (incorporated by reference to Exhibit 10.27 to Targa Resources Inc.'s Registration Statement on Form S-4/A filed December 18, 2007 (File No. 333-147066)).
10.28+	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)).
10.29+	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)).
10.30+	

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)).

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10.31+	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 25, 2011 (File No. 001-33303)).
10.32+	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)).
10.33+	Targa Resources Corp. 2013 Annual Incentive Compensation Plan (incorporated by reference to Exhibit 10.3 to Targa Resources Partner's Current Report on Form 8-K filed January 18, 2013 (File No. 001-33303)).
10.34+	Targa Resources Partners LP 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)).
10.35+	Form of Targa Resources Partners LP 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)).
10.36+	Form of Targa Resources Partners LP Restricted Unit Grant Agreement — 2010 (incorporated by reference to Exhibit 10.15 to Targa Resources Partners LP's Form 10-K filed March 4, 2010 (File No. 001-33303)).
10.37+	Form of Targa Resources Partners LP 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)).
10.38+	Form of Targa Resources Partners LP 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)).
10.39+	Form of Targa Resources Partners LP 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)).
10.40+	Form of Targa Resources Partners LP 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)).
10.41+	Form of Targa Resources Partners LP 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)).
10.42+	Targa Resources Executive Officer Change in Control Severance Program (incorporated by reference to Exhibit 10.3 to Targa Resources Corp.'s Current Report on Form 8-K filed January 19, 2012 (File No. 001-34991)).
10.43	Purchase Agreement dated as of June 12, 2008 among the Issuers, the Guarantors and Deutsche Bank Securities Inc., as representative of the several initial purchasers (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed June 18, 2008) (File No. 001-33303)).
10.44	Indenture dated June 18, 2008, 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 June 18, 2008 (File No. 001-33303)).
10.45	Registration Rights Agreement dated as of June 18, 2008 among the Issuers, the Guarantors and Deutsche Bank Securities Inc., 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 June 18, 2008) (File No. 001-33303)).

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10.46	Supplemental Indenture dated September 24, 2009 to Indenture dated June 18, 2008, among Targa Downstream GP 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 November 9, 2009 (File No. 001-33303)).
10.47	Supplemental Indenture dated September 24, 2009 to Indenture dated June 18, 2008, among Targa Downstream LP, 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 4.5 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).
10.48	Supplemental Indenture dated September 24, 2009 to Indenture dated June 18, 2008, among Targa LSNG GP 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 November 9, 2009 (File No. 001-33303)).
10.49	Supplemental Indenture dated September 24, 2009 to Indenture dated June 18, 2008, among Targa LSNG LP, 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 4.9 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).
10.50	Supplemental Indenture dated September 24, 2009 to Indenture dated June 18, 2008, among Targa Sparta 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 4.11 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).
10.51	Supplemental Indenture dated September 24, 2009 to Indenture dated June 18, 2008, among Midstream Barge Company 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 4.13 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).
10.52	Supplemental Indenture dated September 24, 2009 to Indenture dated June 18, 2008, among Targa Retail Electric 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 4.15 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).
10.53	Supplemental Indenture dated September 24, 2009 to Indenture dated June 18, 2008, among Targa NGL Pipeline Company 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 4.17 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).
10.54	Supplemental Indenture dated September 24, 2009 to Indenture dated June 18, 2008, among Targa Transport 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 4.19 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).
10.55	Supplemental Indenture dated September 24, 2009 to Indenture dated June 18, 2008, among Targa Co-Generation 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 4.21 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).

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10.56	Supplemental Indenture dated September 24, 2009 to Indenture dated June 18, 2008, among Targa Liquids GP 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 4.23 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).
10.57	Supplemental Indenture dated September 24, 2009 to Indenture dated June 18, 2008, among Targa Liquids Marketing and Trade, 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 4.25 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).
10.58	Supplemental Indenture dated April 27, 2010 to Indenture dated June 18, 2008, among Targa Gas Marketing 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 4.1 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed May 6, 2010 (File No. 001-33303)).
10.59	Supplemental Indenture dated April 27, 2010 to Indenture dated June 18, 2008, among Targa Midstream Services Limited Partnership, 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 May 6, 2010 (File No. 001-33303)).
10.60	Supplemental Indenture dated April 27, 2010 to Indenture dated June 18, 2008, among Targa Permian LP, 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 4.5 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed May 6, 2010 (File No. 001-33303)).
10.61	Supplemental Indenture dated April 27, 2010 to Indenture dated June 18, 2008, among Targa Permian Intrastate 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, 2010 (File No. 001-33303)).
10.62	Supplemental Indenture dated April 27, 2010 to Indenture dated June 18, 2008, among Targa Straddle LP, 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 4.9 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed May 6, 2010 (File No. 001-33303)).
10.63	Supplemental Indenture dated April 27, 2010 to Indenture dated June 18, 2008, among Targa Straddle GP 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 4.11 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed May 6, 2010 (File No. 001-33303)).
10.64	Supplemental Indenture dated August 10, 2010 to Indenture dated June 18, 2008, among Targa MLP Capital, 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 10.46 to Targa Resources Corp.'s Registration Statement on Form S-1/A filed November 12, 2010 (File No. 333-169277)).
10.65	Supplemental Indenture dated September 20, 2010 to Indenture dated June 18, 2008, 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 4.3 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed November 5, 2010 (File No. 001-33303)).

10.66	Supplemental Indenture dated October 25, 2010 to Indenture dated June 18, 2008, 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 4.6 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed November 5, 2010 (File No. 001-33303)).
10.67	Supplemental Indenture dated April 8, 2011 to Indenture dated June 18, 2008, 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 4.4 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed May 6, 2011 (File No. 001-33303)).
10.68	Supplemental Indenture dated October 28, 2011 to Indenture dated June 18, 2008, 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 4.1 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed November 7, 2011 (File No. 001-33303)).
10.69	Supplemental Indenture dated April 20, 2012 to Indenture dated June 18, 2008, 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 4.1 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed August 6, 2012 (File No. 001-33303)).
10.70	Purchase Agreement, dated June 30, 2009 among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors named therein and Barclays Capital Inc., as representative of the several initial purchasers (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed July 6, 2009 (File No. 001-33303)).
10.71	Indenture dated July 6, 2009, 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 July 6, 2009 (File No. 001-33303)).
10.72	Registration Rights Agreement dated July 6, 2009, 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 July 6, 2009 (File No. 001-33303)).
10.73	Supplemental Indenture dated September 24, 2009 to Indenture dated July 6, 2009, among Targa Downstream GP 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 November 9, 2009 (File No. 001-33303)).
10.74	Supplemental Indenture dated September 24, 2009 to Indenture dated July 6, 2009, among Targa Downstream LP, 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 November 9, 2009 (File No. 001-33303)).
10.75	Supplemental Indenture dated September 24, 2009 to Indenture dated July 6, 2009, among Targa LSNG GP 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 9, 2009 (File No. 001-33303)).

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10.76 Supplemental Indenture dated September 24, 2009 to Indenture dated July 6, 2009, among Targa LSNG LP, 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 4.10 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).

10.77 Supplemental Indenture dated September 24, 2009 to Indenture dated July 6, 2009, among Targa Sparta 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 4.12 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).

10.78 Supplemental Indenture dated September 24, 2009 to Indenture dated July 6, 2009, among Midstream Barge Company 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 4.14 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).

10.79 Supplemental Indenture dated September 24, 2009 to Indenture dated July 6, 2009, among Targa Retail Electric 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 4.16 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).

10.80 Supplemental Indenture dated September 24, 2009 to Indenture dated July 6, 2009, among Targa NGL Pipeline Company 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 4.18 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).

10.81 Supplemental Indenture dated September 24, 2009 to Indenture dated July 6, 2009, among Targa Transport 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 4.20 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).

10.82 Supplemental Indenture dated September 24, 2009 to Indenture dated July 6, 2009, among Targa Co-Generation 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 4.22 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).

10.83 Supplemental Indenture dated September 24, 2009 to Indenture dated July 6, 2009, among Targa Liquids GP 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 4.24 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).

10.84 Supplemental Indenture dated September 24, 2009 to Indenture dated July 6, 2009, among Targa Liquids Marketing and Trade, 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 4.26 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed November 9, 2009 (File No. 001-33303)).

10.85

Supplemental Indenture dated April 27, 2010 to Indenture dated July 6, 2009, among Targa Gas Marketing 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 May 6, 2010 (File No. 001-33303)).

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10.86	Supplemental Indenture dated April 27, 2010 to Indenture dated July 6, 2009, among Targa Midstream Services Limited Partnership, 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 May 6, 2010 (File No. 001-33303)).
10.87	Supplemental Indenture dated April 27, 2010 to Indenture dated July 6, 2009, among Targa Permian LP, 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, 2010 (File No. 001-33303)).
10.88	Supplemental Indenture dated April 27, 2010 to Indenture dated July 6, 2009, among Targa Permian Intrastate 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 May 6, 2010 (File No. 001-33303)).
10.89	Supplemental Indenture dated April 27, 2010 to Indenture dated July 6, 2009, among Targa Straddle LP, 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 4.10 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed May 6, 2010 (File No. 001-33303)).
10.90	Supplemental Indenture dated April 27, 2010 to Indenture dated July 6, 2009, among Targa Straddle GP 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 4.12 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed May 6, 2010 (File No. 001-33303)).
10.91	Supplemental Indenture dated August 10, 2010 to Indenture dated July 6, 2009, among Targa MLP Capital, 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 10.66 to Targa Resources Corp.'s Registration Statement on Form S-1/A filed November 12, 2010 (File No. 333-169277)).
10.92	Supplemental Indenture dated September 20, 2010 to Indenture dated July 6, 2009, 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 4.4 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed November 5, 2010 (File No. 001-33303)).
10.93	Supplemental Indenture dated October 25, 2010 to Indenture dated July 6, 2009, 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 4.7 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed November 5, 2010 (File No. 001-33303)).
10.94	First Supplemental Indenture dated February 2, 2011 to Indenture dated July 6, 2009, among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors and U.S. Bank National Association (incorporated by reference to Exhibit 4.3 to Targa Resources Partners LP's Current Report on Form 8-K filed February 3, 2011 (File No. 001-33303)).
10.95	Supplemental Indenture dated April 8, 2011 to Indenture dated July 6, 2009, 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 4.5 to Targa Resources Partners LP's Quarterly Report on Form 10-Q filed May 6, 2011 (File No. 001-33303)).

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10.96	Purchase Agreement dated August 10, 2010 among the Issuers, the Guarantors and Banc of America Securities LLC, as representative of the several initial purchasers (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed August 16, 2010 (File No. 001-33303)).
10.97	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)).
10.98	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)).
10.99	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)).
10.100	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)).
10.101	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)).
10.102	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)).
10.103	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)).
10.104	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)).
10.105	Purchase Agreement dated January 19, 2011 by and among the Issuers, the Guarantors and Deutsche Bank Securities Inc., as representative of the several Initial Purchasers (incorporated by reference to Exhibit 1.2 to Targa Resources Partners LP's Current Report on Form 8-K filed January 24, 2011 (File No. 001-33303)).

10.106	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)).

10.107	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 2, 2011 (File No. 001-33303)).
10.108	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)).
10.109	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)).
10.110	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)).
10.111	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)).
10.112	Purchase Agreement dated January 26, 2012 by and among the Issuers, the Guarantors, and Deutsche Bank Securities Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Barclays Capital Inc., Citigroup Global Markets 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 January 31, 2012 (File No. 001-33303).
10.113	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)).
10.114	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)).
10.115	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)).
10.116	

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)).

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10.117	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)).
10.118	Indenture dated as of October 25, 2012 among Targa Resources Partners LP, Targa Resources Partners Finance Corporation and the Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to Targa Resources Partners LP's Current Report on Form 8-K filed October 26, 2012 (File No. 001-33303)).
10.119	Registration Rights Agreement dated as of October 25, 2012 among Targa Resources Partners LP, Targa Resources Partners Finance Corporation, the Guarantors and Merrill Lynch, Pierce, Fenner & Smith Incorporated, Deutsche Bank Securities Inc., Wells Fargo Securities, LLC, Barclays Capital Inc. and RBS Securities Inc., as representatives of the several initial purchasers (incorporated by reference to Exhibit 4.2 to Targa Resources Partners LP's Current Report on Form 8-K filed October 26, 2012 (File No. 001-33303)).
10.120	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)).
10.121	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)).
10.122	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)).
10.123	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)).
10.124	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)).
10.125	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)).
10.126	Contribution, Conveyance and Assumption Agreement, dated April 27, 2010, by and among Targa Resources Partners LP, Targa LP Inc., Targa Permian GP LLC, Targa Midstream Holdings LLC, Targa Resources Operating LP, Targa North Texas GP LLC and Targa Resources Texas GP LLC (incorporated by reference to Exhibit 10.1 to Targa Resources Partners LP's Current Report on Form 8-K filed April 29, 2010 (File No. 001-33303)).

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10.127	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)).
10.128	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)).
10.129	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)).
10.130	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)).
10.131+	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)).
10.132+	Targa Resources Partners LP Indemnification Agreement for Barry R. Pearl 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)).
10.133+	Targa Resources Partners LP Indemnification Agreement for Robert B. Evans 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)).
10.134+	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)).
10.135+	Targa Resources Partners LP Indemnification Agreement for Ruth I. Dreessen (incorporated by reference to Exhibit 10.44 to Targa Resource Partners LP's Annual Report on Form 10-K filed February 19, 2013 (File No. 001-33303)).
10.136	Amended and Restated Registration Rights Agreement dated as of October 31, 2005 (incorporated by reference to Exhibit 10.1 to Targa Resources Corp.'s Registration Statement on Form S-1/A filed November 12, 2010 (File No. 333-169277)).
21.1*	List of Subsidiaries of Targa Resources Corp.
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.

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32.2**	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS**	XBRL Instance Document
101.SCH**	XBRL Taxonomy Extension Schema Document
101.CAL**	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF**	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB**	XBRL Taxonomy Extension Label Linkbase Document
101.PRE**	XBRL Taxonomy Extension Presentation Linkbase Document

* Filed herewith

** Furnished herewith

*** Pursuant to Item 601(b)(2) of Regulation S-K, the Company agrees to furnish supplementally a copy of any omitted exhibit or Schedule to the SEC upon request.

+ Management contract or compensatory plan or arrangement

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SIGNATURES

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

Targa Resources Corp.
(Registrant)

Date: February 19, 2013

By: /s/ Matthew J. Meloy
Matthew J. Meloy
Senior Vice President, Chief Financial Officer and Treasurer
(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 19, 2013.

Signature	Title (Position with Targa Resources Corp.)
/s/ Joe Bob Perkins Joe Bob Perkins	Chief Executive Officer and Director (Principal Executive Officer)
/s/ Matthew J. Meloy Mathew J. Meloy	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/ Charles R. Crisp Charles R. Crisp	Director
/s/ In Seon Hwang In Seon Hwang	Director
/s/ Peter R. Kagan Peter R. Kagan	Director
/s/ Ershel C. Redd Jr. Ershel C. Redd Jr.	Director
/s/ Chris Tong Chris Tong	Director

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INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

TARGA RESOURCES CORP. AUDITED CONSOLIDATED FINANCIAL STATEMENTS

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

Management has used the framework set forth in the report entitled "Internal Control—Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") to evaluate the effectiveness of the internal control over financial reporting. Based on that evaluation, management has concluded that the internal control over financial reporting was effective as of December 31, 2012.

The business of Saddle Butte Pipeline, LLC that the Partnership purchased on December 31, 2012 was excluded from the scope of our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2012. This business constituted 20.1% of our total assets as of December 31, 2012.

The effectiveness of our internal control over financial reporting as of December 31, 2012 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears on page F-3.

/s/ Joe Bob Perkins
Joe Bob Perkins
Chief Executive Officer
(Principal Executive Officer)

/s/ Matthew J. Meloy
Matthew J. Meloy
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

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Report of Independent Registered Public Accounting Firm

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

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 Corp. and its subsidiaries (the "Company") at December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company'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 Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

As described in Management's Report on Internal Control Over Financial Reporting, management has excluded from its assessment of internal control over financial reporting as of December 31, 2012 the business of Saddle Butte Pipeline, LLC acquired in a purchase business combination as of December 31, 2012. We have also excluded the acquired business from our audit of internal control over financial reporting. The total assets of the acquired business represent 20.1% of the related consolidated financial statement amounts as of December 31, 2012.

/s/PricewaterhouseCoopers LLP
Houston, Texas
February 19, 2013

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TARGA RESOURCES CORP.
CONSOLIDATED BALANCE SHEETS

	December 31, 2012	December 31, 2011
	(In millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	$76.3	$145.8
Trade receivables, net of allowances of $0.9 million and $2.4 million	514.9	575.7
Inventories	99.4	92.2
Deferred income taxes	-	0.1
Assets from risk management activities	29.3	41.0
Other current assets	13.4	11.7
Total current assets	733.3	866.5
Property, plant and equipment	4,708.0	3,821.1
Accumulated depreciation	(1,170.0)	(1,001.6)
Property, plant and equipment, net	3,538.0	2,819.5
Long-term assets from risk management activities	5.1	10.9
Investment in unconsolidated affiliate	53.1	36.8
Other intangible assets, net	680.8	1.4
Other long-term assets	94.7	95.9
Total assets	$5,105.0	$3,831.0
LIABILITIES AND OWNERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$679.0	$700.0
Deferred income taxes	0.2	-
Liabilities from risk management activities	7.4	41.1
Total current liabilities	686.6	741.1
Long-term debt	2,475.3	1,567.0
Long-term liabilities from risk management activities	4.8	15.8
Deferred income taxes	131.2	120.5
Other long-term liabilities	53.7	55.9
Commitments and contingencies (see Note 17)		
Owners' equity:		
Targa Resources Corp. stockholders' equity:		
Common stock ($0.001 par value, 300,000,000 shares authorized, 42,492,233 shares issued and 42,294,502 shares outstanding as of December 31, 2012, and 42,398,148 shares issued and outstanding as of December 31, 2011)	-	-
Preferred stock ($0.001 par value, 100,000,000 shares authorized, no shares issued and outstanding as of December 31, 2012 and December 31, 2011)	-	-
Additional paid-in capital	184.4	229.5
Accumulated deficit	(32.0)	(70.1)
Accumulated other comprehensive income (loss)	1.2	(1.3)
	(9.5)	-

Treasury stock, at cost (197,731 shares as of December 31, 2012 and no shares as of December 31, 2011)		
Total Targa Resources Corp. stockholders' equity	144.1	158.1
Noncontrolling interests in subsidiaries	1,609.3	1,172.6
Total owners' equity	1,753.4	1,330.7
Total liabilities and owners' equity	$5,105.0	$3,831.0

See notes to consolidated financial statements.

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TARGA RESOURCES CORP.
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2012	2011	2010
	(In millions, except per share amounts)		
Revenues	$5,885.7	$6,994.5	$5,476.1
Costs and expenses:			
Product purchases	4,879.0	6,039.0	4,695.5
Operating expenses	313.1	287.1	259.3
Depreciation and amortization expenses	197.6	181.0	185.5
General and administrative expenses	139.8	136.1	144.4
Other operating (income) expense (See Note 19)	19.9	0.2	(4.7)
Income from operations	336.3	351.1	196.1
Other income (expense):			
Interest expense, net	(120.8)	(111.7)	(110.9)
Equity earnings	1.9	8.8	5.4
Loss on debt redemption (See Note 10)	(11.1)	-	(17.4)
Gain (loss) on early debt extinguishment, net (See Note 10)	(1.7)	-	12.5
Loss on mark-to-market derivative instruments	-	(5.0)	(0.4)
Other	(8.4)	(1.2)	0.5
Income before income taxes	196.2	242.0	85.8
Income tax expense:			
Current	(27.9)	(14.3)	10.6
Deferred	(9.0)	(12.3)	(33.1)
	(36.9)	(26.6)	(22.5)
Net income	159.3	215.4	63.3
Less: Net income attributable to noncontrolling interests	121.2	184.7	78.3
Net income (loss) available to Targa Resources Corp.	38.1	30.7	(15.0)
Dividends on Series B preferred stock	-	-	(9.5)
Dividends on common equivalents	-	-	(177.8)
Net income (loss) available to common shareholders	$38.1	$30.7	$(202.3)
Net income (loss) available per common share - basic	$0.93	$0.75	$(30.94)
Net income (loss) available per common share - diluted	$0.91	$0.74	$(30.94)
Weighted average shares outstanding - basic	41.0	41.0	6.5
Weighted average shares outstanding - diluted	41.8	41.4	6.5

See notes to consolidated financial statements.

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TARGA RESOURCES CORP.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Year Ended December 31,								
	2012			2011			2010		
	Pre-Tax	Related Income Tax	After Tax	Pre-Tax	Related Income Tax	After Tax	Pre-Tax	Related Income Tax	After Tax
	(In millions)								
Net income (loss) attributable to Targa Resources Corp.			$38.1			$30.7			$(15.0)
Other comprehensive income (loss) attributable to Targa Resources Corp.									
Commodity hedging contracts:									
Change in fair value	$11.9	$(4.4)	7.5	$(5.2)	$2.1	(3.1)	$37.8	$(14.3)	23.5
Settlements reclassified to revenues	(9.0)	3.3	(5.7)	1.0	(0.4)	0.6	(4.0)	1.5	(2.5)
Interest rate swaps:									
Change in fair value	-		-	(0.3)	0.1	(0.2)	(2.1)	1.3	(0.8)
Settlements reclassified to interest expense, net	1.3	(0.6)	0.7	1.3	(0.5)	0.8	1.8	(1.1)	0.7
Other comprehensive income (loss) attributable to Targa Resources Corp.	$4.2	$(1.7)	2.5	$(3.2)	$1.3	(1.9)	$33.5	$(12.6)	20.9
Comprehensive income attributable to			$40.6			$28.8			$5.9

Targa Resources Corp.									
Net income attributable to noncontrolling interests			$121.2			$184.7			$78.3
Other comprehensive income (loss) attributable to noncontrolling interests									
Commodity hedging contracts:									
Change in fair value	$64.9	$-	64.9	$(28.4)	$-	(28.4)	$14.9	$-	14.9
Settlements reclassified to revenues	(37.0)	-	(37.0)	29.3	-	29.3	(4.7)	-	(4.7)
Interest rate swaps:									
Change in fair value	-	-	-	(4.0)	-	(4.0)	(18.0)	-	(18.0)
Settlements reclassified to interest expense, net	6.6	-	6.6	6.8	-	6.8	7.4	-	7.4
Other comprehensive income (loss) attributable to noncontrolling interests	$34.5	$-	34.5	$3.7	$-	3.7	$(0.4)	$-	(0.4)
Comprehensive income attributable to noncontrolling interests			155.7			188.4			77.9
Total comprehensive income			$196.3			$217.2			$83.8

See notes to consolidated financial statements.

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TARGA RESOURCES CORP.
CONSOLIDATED STATEMENTS OF CHANGES IN OWNERS' EQUITY

	Common Stock		Additional Paid in	Accumulated	Accumulated Other Comprehensive Income	Treasury Shares		Noncontrolling	
	Shares	Amount	Capital	Deficit	(Loss)	Shares	Amount	Interests	Total
	(In millions, except shares in thousands)								
Balance, December 31, 2009	3,910	$-	$ 194.0	$ (85.8)	$ (20.3)	97.0	$(0.5)	$ 667.5	$754.9
Option exercises	1,161	-	0.6	-	-	(69)	0.3	-	0.9
Compensation equity grants	1,906	-	13.8	-	-	-	-	-	13.8
Repurchase of common stock	-	-	-	-	-	13	(0.1)	-	(0.1)
Proceeds from sale of limited partner interests in the Partnership	-	-	-	-	-	-	-	224.4	224.4
Impact of Partnership equity transactions	-	-	258.9	-	-	-	-	(258.9)	-
Tax impact of equity offerings	-	-	(79.6)	-	-	-	-	-	(79.6)
Dividends to common and common equivalents	-	-	(213.3)	-	-	-	-	-	(213.3)
Dividends on Series B preferred stock	-	-	(9.5)	-	-	-	-	-	(9.5)
Contributions	-	-	-	-	-	-	-	317.8	317.8
Distributions	-	-	-	-	-	-	-	(136.9)	(136.9)
Series B Preferred conversion	35,356	-	79.9	-	-	-	-	-	79.9
Other comprehensive income (loss)	-	-	-	-	20.9	-	-	(0.4)	20.5
Treasury shares retired	(41)	-	(0.3)	-	-	(41)	0.3	-	-
Net income (loss)	-	-	-	(15.0)	-	-	-	78.3	63.3

Balance, December 31, 2010	42,292	$-	$ 244.5	$ (100.8)	$ 0.6	-	$-	$ 891.8	$1,036.1
Compensation on equity grants	106	-	14.2	-	-	-	-	1.0	15.2
Sale of Partnership limited partner interests	-	-	-	-	-	-	-	298.0	298.0
Impact of Partnership equity transactions	-	-	10.3	-	-	-	-	(10.3)	-
Dividends	-	-	(39.5)	-	-	-	-	(0.1)	(39.6)
Distributions to owners	-	-	-	-	-	-	-	(196.2)	(196.2)
Other comprehensive income (loss)	-	-	-	-	(1.9)	-	-	3.7	1.8
Net income	-	-	-	30.7	-	-	-	184.7	215.4
Balance, December 31, 2011	42,398	$-	$ 229.5	$ (70.1)	$ (1.3)	-	$-	$ 1,172.6	$1,330.7
Compensation on equity grants	95	-	15.3	-	-	-	-	3.5	18.8
Repurchase of common stock	(198)	-	-	-	-	198	(9.5)	-	(9.5)
Sale of Partnership limited partner interests	-	-	-	-	-	-	-	493.5	493.5
Impact of Partnership equity transactions	-	-	5.2	-	-	-	-	(5.2)	-
Dividends	-	-	(64.4)	-	-	-	-	(0.5)	(64.9)
Distributions to owners	-	-	(1.2)	-	-	-	-	(210.3)	(211.5)
Other comprehensive income (loss)	-	-	-	-	2.5	-	-	34.5	37.0
Net income	-	-	-	38.1	-	-	-	121.2	159.3
Balance, December 31, 2012	42,295	$-	$ 184.4	$ (32.0)	$ 1.2	198	$(9.5)	$ 1,609.3	$1,753.4

See notes to consolidated financial statements.

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TARGA RESOURCES CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2012	2011	2010
Cash flows from operating activities		(In millions)	
Net income	$159.3	$215.4	$63.3
Adjustments to reconcile net income to net cash provided by operating activities:			
Amortization in interest expense	18.2	13.0	9.4
Paid-in-kind interest expense	-	-	10.9
Compensation on equity grants	17.5	15.2	13.4
Depreciation and amortization expense	197.6	181.0	174.7
Asset retirement obligations estimate change	-	-	10.8
Accretion of asset retirement obligations	4.0	3.6	3.2
Deferred income tax expense	9.0	12.3	33.1
Equity earnings, net of distributions	-	(0.4)	-
Risk management activities	3.6	(21.2)	29.9
Payments of interest on Holdco loan facility	-	-	(0.9)
Loss (gain) on sale or disposition of assets	15.6	0.2	(1.5)
Loss on debt redemption	11.1	-	17.4
Loss (gain) on early debt extinguishment	1.7	-	(12.5)
Changes in operating assets and liabilities:			
Receivables and other assets	98.0	(101.3)	(119.2)
Inventory	6.0	(41.1)	(11.4)
Accounts payable and other liabilities	(113.4)	102.6	(15.4)
Net cash provided by operating activities	428.2	379.3	205.2
Cash flows from investing activities			
Outlays for property, plant and equipment	(582.7)	(331.9)	(139.3)
Business acquisitions, net of cash acquired	(996.2)	(156.5)	-
Investment in unconsolidated affiliate	(16.8)	(21.2)	-
Return of capital from unconsolidated affiliate	0.5	-	3.3
Other, net	4.5	0.3	4.7
Net cash used in investing activities	(1,590.7)	(509.3)	(131.3)
Cash flows from financing activities			
Partnership loan facilities:			
Proceeds	2,595.0	2,112.0	1,593.1
Repayments	(1,690.7)	(2,054.3)	(1,057.0)
Cash paid on note exchange	-	(27.7)	-
Non-Partnership loan facilities:			
Proceeds	90.0	-	495.0
Repayments	(96.8)	-	(1,087.4)
Costs incurred in connection with financing arrangements	(16.1)	(6.2)	(39.6)
Distributions to owners	(211.5)	(196.2)	(136.9)
Proceeds from sale of common units of the Partnership	493.5	298.0	224.4
Dividends to common and common equivalent shareholders	(62.2)	(38.2)	(210.1)
Repurchase of common stock	(9.5)	-	(0.1)
Excess tax benefit from stock-based awards	1.3	-	-

Partnership equity transactions	-	-	317.8
Stock options exercised	-	-	0.9
Dividends to preferred shareholders	-	-	(238.0)
Net cash provided by financing activities	1,093.0	87.4	(137.9)
Net change in cash and cash equivalents	(69.5)	(42.6)	(64.0)
Cash and cash equivalents, beginning of period	145.8	188.4	252.4
Cash and cash equivalents, end of period	$76.3	$145.8	$188.4

See notes to consolidated financial statements.

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TARGA RESOURCES CORP.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

Note 1 — Organization

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

Note 2 — Basis of Presentation

These accompanying financial statements and related notes present our consolidated financial position as of December 31, 2012 and 2011, and the results of operations, comprehensive income, cash flows, and changes in owners' equity for the years ended December 31, 2012, 2011 and 2010.

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

One of our indirect subsidiaries is the sole general partner of Targa Resources Partners LP ("the Partnership"). Because we control the general partner of the Partnership, under generally accepted accounting principles, we must reflect our ownership interests in the Partnership on a consolidated basis. Accordingly, the Partnership's financial results are included in our consolidated financial statements even though the distribution or transfer of Partnership assets is limited by the terms of the partnership agreement, as well as restrictive covenants in the Partnership's lending agreements. The limited partner interests in the Partnership not owned by controlling affiliates of us are reflected in our results of operations as net income attributable to noncontrolling interests and in our balance sheet equity section as noncontrolling interests in subsidiaries. Throughout these footnotes, we make a distinction where relevant between financial results of the Partnership versus those of a standalone parent and its non-partnership subsidiaries.

As of December 31, 2012, our interests in the Partnership consist of the following:

- a 2% general partner interest, which we hold through our 100% ownership interest in the general partner of the Partnership;
- all Incentive Distribution Rights ("IDR"); and
- 12,945,659 common units of the Partnership, representing a 12.7% limited partnership interest.

The Partnership is engaged in the business of gathering, compressing, treating, processing and selling natural gas; storing, fractionating, treating, transporting and selling natural gas liquids ("NGL") and NGL products; and storing and terminaling refined petroleum products and crude oil. See Note 23 for an analysis of our and the Partnership's operations by segment.

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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

The Partnership’s 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 the Partnership’s customers. NGL product inventories are valued at the lower of cost or market using the average cost method. Inventories also include materials and supplies required for the Partnership’s Badlands expansion activities in North Dakota, which are valued at lower cost or market 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.

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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. 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 capitalize certain costs directly related to the construction of assets, including internal labor costs, interest and engineering costs. Upon disposition or retirement of property, plant and equipment, any gain or loss is recorded to operations.

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.

Asset Retirement Obligations ("AROs")

AROs are legal obligations associated with the retirement of tangible long-lived assets that result from the 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.

Environmental Liabilities

Liabilities for loss contingencies, including environmental remediation costs arising from claims, assessments, litigation, fines, and penalties and other sources are charged to expense when it is probable that a liability has been incurred and the amount of the assessment and/or remediation can be reasonably estimated. See Note 17.

Income Taxes

We account for income taxes using the asset and liability method of accounting for deferred income taxes and provide deferred income taxes for all significant temporary differences.

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

We must then assess the likelihood that our deferred tax assets will be recovered from future taxable income and, to the extent we believe that it is more likely than not (a likelihood of more than 50%) that some portion or all of the deferred tax assets will not be realized, we establish a valuation allowance. Any change in the valuation allowance would impact our income tax provision and net income in the period in which such a determination is made. We consider all available evidence, both positive and negative, to determine whether, based on the weight of the evidence, a valuation allowance is needed. Evidence used includes information about our current financial position and our results of operations for the current and preceding years, as well as all currently available information about future years, including our anticipated future performance, the reversal of deferred tax liabilities and tax planning strategies.

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We believe future sources of taxable income, reversing temporary differences and other tax planning strategies will be sufficient to realize assets for which no reserve has been established.

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, noncontrolling interests reflects the allocation of earnings to third-party investors, which for the Partnership gives effect to the incentive distribution rights declared for each period. We account for the difference between the carrying amount of our investment in the Partnership and the underlying book value arising from issuance of common units by the Partnership, where we maintain control, as an equity transaction. If the Partnership issues common units at a price different than our carrying value per unit, we account for the premium or deficiency as an adjustment to paid-in capital.

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.

Share-Based Compensation

We award share-based compensation to employees, directors and non-management directors in the form of restricted stock, stock options and performance unit awards. 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 22.

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Earnings per Share

We account for earnings per share (EPS) in accordance with ASC 260 – Earnings per Share. Diluted EPS reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock or resulted in the issuance of common stock so long as it does not have an anti-dilutive effect on EPS. The dilutive effect is determined through the application of the treasury method. Securities that meet the definition of a participating security are required to be considered for inclusion in the computation of basic earnings per unit. Prior to the conversion of the Series B Preferred Stock on December 10, 2010, we used the two-class method of allocating earnings between our common and preferred class of stock outstanding for the purposes of presenting net income per share.

Use of Estimates

When preparing financial statements in conformity with accounting principles generally accepted in the United States of America, 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 December 2011, the FASB issued Accounting Standards Update No. 2011-11, Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities. The amendment, required to be applied for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods, requires an entity to disclose information about offsetting assets and liabilities and related netting arrangements. In January 2013, the FASB also issued Accounting Standards Update No. 2013-01, Balance Sheet (Topic 210): Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities, which clarifies that ASU 2011-11 applies to financial instruments or derivative transactions accounted for under ASC 815. The amendments require disclosures to present both gross and net amounts of derivative assets and liabilities that are subject to master netting arrangements with counterparties. We currently present our derivative assets and liabilities gross on our statement of financial position. We will provide additional disclosures regarding the gross and net amounts of derivative assets and liabilities beginning with reporting periods in 2013 in accordance with these amendments.

Accounting Standards Update No. 2011-04, Fair Value Measurements (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS, was implemented in 2012. Note 13 includes additional disclosures regarding the fair value and fair value hierarchy classification of financial instruments reported at carrying value in our Consolidated Balance Sheets. Additionally, we have provided information regarding the unobservable inputs used in the fair value measurement of derivative contracts classified within Level 3 of the fair value hierarchy. Transfers among levels of the fair value hierarchy are deemed to occur at the end of the reporting period.

Accounting Standards Update No. 2011-05, Comprehensive Income (Topic 220): Presentation of Comprehensive Income was retroactively adopted during 2012. We now display in the Consolidated Statements of Comprehensive Income (Loss) the tax effect, if any, of each component of other comprehensive income.

In February 2013, the FASB issued Accounting Standards Update No. 2013-2, 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. Early adoption is permitted. Our financial statement presentation complies with this standards update.

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Note 4 –Business Acquisitions

2011 Acquisitions

In March 2011, the Partnership 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 544,000 barrels, can handle multiple grades of blend stocks, petroleum products and crude oil and has potential for expansion, as well as integration with the Partnership’s other logistics operations.

In September 2011, the Partnership acquired two refined petroleum products and crude oil storage and terminaling facilities. The facility on the Hylebos Waterway in the Port of Tacoma, Washington has 758,000 barrels 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 505,000 barrels 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.

2012 Acquisition

Badlands

On December 31, 2012, the Partnership 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 customary purchase price adjustments and a contingent payment.

The acquired business is located in the Williston Basin of the Bakken Shale Play in the McKenzie, Dunn and Mountrail counties of North Dakota and includes approximately 155 miles of crude oil pipelines. The business has combined crude oil operational storage capacity of 70,000 barrels, including the Johnsons Corner Terminal with 20,000 barrels of storage capacity (expanding to 40,000 barrels) and the Alexander Terminal with storage capacity of 30,000 barrels, with a combined estimated throughput of 32,000 barrels per day. It also includes approximately 95 miles of natural gas gathering pipelines and a 20 MMcf/d natural gas processing plant with an expansion underway to increase capacity to 40 MMcf/d. The operations are backed by producer dedications under long-term contracts that include approximately 260,000 acres of crude oil production and over 100,000 acres of natural gas production. The Badlands acquisition expands the Partnership’s portfolio of midstream assets, extends its footprint to the Bakken Shale / Three Forks play and diversifies its business with the addition of crude oil gathering. The Badlands financial results will be included in the Partnership’s Field Gathering and Processing business segment.

Pursuant to the Membership Interest Purchase and Sale Agreement, 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, the Partnership 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 Membership Interest Purchase and Sale Agreement. Future changes in the fair value of this accrued liability must be included in earnings.

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The following table summarizes the consideration paid for the Badlands acquisition and the preliminary determination of the assets and liabilities acquired at the December 31, 2012 acquisition date.

Cash	$	975.8
Contingent consideration		15.3
Total consideration	$	991.1

Assets acquired and liabilities assumed		Amount
Financial assets	$	35.4
Inventory		16.2
Property, plant and equipment		295.3
Intangible assets	$	679.6
Financial liabilities		(35.4)
Net tangible and intangible assets acquired	$	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. During 2013, the Partnership will determine the amortization methods and estimate useful lives for the Badlands 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. The Partnership incurred $6.1 million of acquisition-related costs associated with the Badlands acquisition (included in Other expense in the consolidated statement of operations). The following unaudited pro forma consolidated results of operations for the years ended 2012 and 2011 are presented as if the Badlands acquisition had been completed on January 1, 2011.

		2012		2011
	(In millions except per share amounts)			
Revenues	$	5,928.5	$	7,012.8
Net income		134.5		179.8
Less: Net income attributable to noncontrolling interests		90.1		140.1
Net income attributable to Targa Resources Corp.	$	44.4	$	39.7
Net income per common share - Basic	$	1.08	$	0.97
Net income per common share - Diluted	$	1.06	$	0.96

The pro forma consolidated results of operations include adjustments to include the reported results of acquired company for 2012 and 2011, as adjusted to:

- exclude the financial results of assets retained by the seller;

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- 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;
- include the incremental depreciation and amortization expenses associated with the fair value adjustments to property, plant and equipment and definite-lived intangibles as a result of applying the acquisition method of accounting (assumed straight-line method over useful lives of 30 years for plant, property and equipment and 30 years for intangible assets);
- include the financing costs associated with the Partnership's debt offering and borrowings under the Partnership's Senior Secured Credit Facility used to fund a portion of the acquisition;
- adjust the attribution of net income to noncontrolling interests to give effect to the pro forma adjustments on the Partnership's net income;
- include the income tax effect for us; and
- excludes $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.

Note 5 — Inventory

The components of inventory consisted of the following:

	December 31, 2012	December 31, 2011
Natural gas liquids	$ 82.3	$ 91.5
Materials and supplies	17.1	0.7
	$ 99.4	$ 92.2

Note 6 — Property, Plant and Equipment

	December 31, 2012			December 31, 2011				
	Targa Resources Partners LP	TRC Non-Partnership	Targa Resources Corp. Consolidated	Targa Resources Partners LP	TRC Non-Partnership	Targa Resources Corp. Consolidated	Estimated Useful Lives (In Years)	
Gathering systems	$1,896.8	$-	$ 1,896.8	$1,740.6	$-	$ 1,740.6	5 to 20	(1)
Processing and fractionation facilities	1,152.2	6.6	1,158.8	1,062.7	6.6	1,069.3	5 to 25	
Terminaling and storage facilities	640.3	-	640.3	380.7	-	380.7	5 to 25	(1)
Transportation assets	292.5	-	292.5	281.2	-	281.2	10 to 25	
Other property, plant and equipment	84.2	0.2	84.4	54.9	24.0	78.9	3 to 25	

Land	87.1	-	87.1	71.2	-	71.2	-
Construction in progress	548.1	-	548.1	195.6	3.6	199.2	-
	$4,701.2	$6.8	$ 4,708.0	$3,786.9	$34.2	$ 3,821.1	

(1) The useful lives of the Badlands assets acquired on December 31, 2012 will be determined in 2013 in conjunction with our finalization of the preliminary fair value acquisition accounting.

Capitalized interest was $13.6 million, $3.4 million and $1.3 million in 2012, 2011 and 2010.

Note 7 – Asset Retirement Obligations

Our asset retirement obligations primarily relate to certain of the Partnership's 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:

	2012	2011	2010
Beginning of period	$ 42.3	$ 37.5	$ 34.1
Change in cash flow estimate	(1.0)	1.2	0.2
Accretion expense	4.0	3.6	3.2
End of period	$ 45.3	$ 42.3	$ 37.5

Note 8 – Investment in Unconsolidated Affiliate

At December 31, 2012, 2011 and 2010, the Partnership's 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:

	2012	2011	2010
Equity earnings	$ 1.9	$ 8.8	$ 5.4
Cash distributions (1)	2.3	8.4	8.7
Cash calls for expansion projects	16.8	21.2	-

(1) Pursuant to the Purchase and Sale Agreement for the conveyance of the Downstream Business to the Partnership, we were entitled to receive GCF distributions of $2.3 million in 2010.

Note 9 — Accounts Payable and Accrued Liabilities

The components of accounts payable and accrued liabilities consisted of the following:

	December 31, 2012	December 31, 2011
Commodities	$ 416.8	$ 515.3
Other goods and services	154.4	88.2
Interest	39.5	32.4
Compensation and benefits	40.7	46.1
Other	27.6	18.0
	$ 679.0	$ 700.0

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Note 10 — Debt Obligations

	2012	2011
Long-term debt:		
Non-Partnership obligations:		
TRC Holdco loan facility, variable rate, due February 2015	$-	$89.3
TRC Senior secured revolving credit facility, variable rate, due October 2017 (1)	82.0	-
Obligations of the Partnership: (2)		
Senior secured revolving credit facility, variable rate, due October 2017 (3)	620.0	498.0
Senior unsecured notes, 8¼% fixed rate, due July 2016	-	209.1
Senior unsecured notes, 11¼% fixed rate, due July 2017	72.7	72.7
Unamortized discount	(2.5)	(2.9)
Senior unsecured notes, 7 % fixed rate, due October 2018	250.0	250.0
Senior unsecured notes, 6 % fixed rate, due February 2021	483.6	483.6
Unamortized discount	(30.5)	(32.8)
Senior unsecured notes, 6 % fixed rate, due August 2022	400.0	-
Senior unsecured notes, 5¼% fixed rate, due May 2023	600.0	-
Total long-term debt	$2,475.3	$1,567.0
Irrevocable standby letters of credit:		
Letters of credit outstanding under TRC Senior secured credit facility (1)	$-	$-
Letters of credit outstanding under the Partnership senior secured revolving credit facility (3)	45.3	92.5
	$45.3	$92.5

(1) As of December 31, 2012, $68.0 million of TRC's $150.0 million credit facility was available.

(2) While we consolidate the debt of the Partnership in our financial statements, we do not have the obligation to make interest payments or debt payments with respect to the debt of the Partnership.

(3) As of December 31, 2012, availability under the Partnership's $1.2 billion senior secured revolving credit facility was $534.7 million.

The following table shows contractually scheduled maturities of our and the Partnership's debt obligations outstanding at December 31, 2012 for the next five years, and in total thereafter:

	Scheduled Maturities of Debt			
	Total	2013 - 2016	2017	After 2017
TRC Senior secured credit facility	$82.0	$-	$82.0	$-
Partnership's Senior secured credit facility	620.0	-	620.0	-
Partnership's Senior unsecured notes	1,806.3	-	72.7	1,733.6
Total	$2,508.3	$-	$774.7	$1,733.6

The following table shows the range of interest rates and weighted average interest rate incurred on our and the Partnership's variable-rate debt obligations during the year ended December 31, 2012:

	Range of Interest Rates Incurred	Weighted Average Interest Rate Incurred
TRC Senior secured revolving credit facility	3.0% - 5.0%	3.1%

TRC Holdco loan facility	3.2% - 3.3%	3.2	%
Partnership's Senior secured revolving credit facility	1.9% - 4.5%	2.5	%

Compliance with Debt Covenants

As of December 31, 2012, both we and the Partnership were in compliance with the covenants contained in our various debt agreements.

TRC Credit Agreement

In January 2010 TRI entered into a Senior Secured Credit Agreement providing senior secured financing of $600 million, consisting of a $500 million Senior Secured Term Loan due October 2012 (the “term loan”) and a $100 million Senior Secured Revolving Credit Facility due July 2014 (the “credit facility”). Concurrent with the execution of the credit agreement, TRI borrowed $500 million on the term loan facility net of a $5 million discount. There was no initial funding on the revolving credit line. The proceeds from the term loan were used to:

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- complete the cash tender offer and consent solicitation for all $250 million of TRI's outstanding 8½ senior notes due 2013;
- repay the outstanding balance of $62.2 million on TRI's existing term loan;
- purchase $164.2 million in face value of the Holdco Notes for $131.4 million; and
- fund working capital and pay fees and expenses under the credit agreement.

In 2010, TRI incurred a loss on debt repurchases of $17.4 million comprising $10.9 million of premiums paid and $6.5 million from the write-off of the debt issue costs related to the repurchase of TRI's 8½ senior notes, discussed above. The premiums paid were included as a cash outflow from a financing activity in the Statement of Cash Flows.

In 2010, our term loan facility was paid in full and the available capacity of the credit facility was reduced to $75.0 million. The entire amount of our credit facility was available for letters of credit and includes a limited capacity for borrowings on same-day notice referred to as swing line loans. We wrote-off $21.5 million deferred debt issue costs associated with the term loan facility when the term loan was paid in full.

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

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

The TRC Revolver bears interest, at our option, at either (a) a base rate equal to the highest of the prime rate of Deutsche Bank Trust Company Americas, the administrative agent, the federal funds rate plus 0.5% and the one-month LIBOR rate plus 1.0%, plus an applicable margin ranging from 1.75% to 2.5% (dependent upon the Company's consolidated leverage ratio), or (b) LIBOR plus an applicable margin ranging from 2.75% to 3.5% (dependent upon the Company's consolidated leverage ratio).

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

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

TRC Holdco Loan Facility

In August 2007, we borrowed $450 million under the TRC Holdco loan facility (“Holdco debt”).

The following subsidiary repurchases of Holdco debt have been recognized in the accompanying consolidated financial statements as extinguishments of debt:

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- In 2010, TRI and another wholly-owned subsidiary paid $269.3 million to extinguish $306.1 million of outstanding borrowings (including accrued interest of $23.1 million), resulting in a pretax gain of $36.8 million. In addition, we wrote-off $2.0 million of associated unamortized deferred debt issue costs.

- In 2012, using proceeds from our TRC Revolver, we paid $88.8 million to extinguish the remaining $89.3 million outstanding borrowings of Holdco debt, resulting in a pretax gain of $0.5 million. In addition, we wrote-off $0.3 million of associated unamortized deferred debt issue costs.

The Partnership's Revolving Credit Agreement

In July 2010, the Partnership entered into an Amended and Restated Credit Agreement that replaced the Partnership's existing variable rate Senior Secured Credit Facility due February 2012 with a new variable rate Revolver due July 2015. The Amended and Restated Credit Agreement increased available commitments to $1.1 billion from $958.5 million and allowed the Partnership to request increases in commitments up to an additional $300 million.

The Partnership incurred a charge of $0.8 million related to a partial write-off of debt issue costs associated with this Amended and Restated Credit Agreement related to a change in syndicate members. The remaining balance in debt issue costs of $4.7 million was amortized over the life of the Amended and Restated Credit Agreement.

In October 2012, the Partnership entered into a Second Amended and Restated Credit Agreement that amends and replaces the Partnership's existing 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 increases 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.

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

The Partnership is 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 from 1.75% to 2.75%.

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

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

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The Partnership's Senior Unsecured Notes

In February 2011, the Partnership exchanged $158.6 million principal amount of its 6 % Notes plus payments of $28.6 million, including $0.9 million of accrued interest, for $158.6 million aggregate principal amount of its 11¼% Notes. The holders of the exchanged Notes are subject to the provisions of the 6 % 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, the Partnership privately placed $400.0 million in aggregate principal amount of its 6 % Notes, resulting in approximately $395.5 million of net proceeds.

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

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

The terms of the senior unsecured notes outstanding as of December 31, 2012 were as follows:

Note Issue	Issue Date	Per Annum Interest Rate	Due Date	Dates Interest Paid
"11¼% Notes"	July 2009	11¼%	July 15, 2017	January & July 15th
"7 % Notes"	August 2010	7 %	October 15, 2018	April & October 15th
"6 % Notes"	February 2011	6 %	February 1, 2021	January & July 1st
"6 % Notes"	January 2012	6 %	August 1, 2022	February & August 1st
"5¼% Notes"	Oct / Dec 2012	5¼%	May 1, 2023	May & November 1st

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 Partnership's credit facility. They are senior in right of payment to any of our future subordinated indebtedness and are unconditionally guaranteed by the Partnership. These notes are effectively subordinated to all secured indebtedness under the Partnership's credit agreement, which is secured by substantially all of the Partnership's assets and the Partnership's Securitization Facility, which is secured by accounts receivable pledged under the facility, to the extent of the value of the collateral securing that indebtedness. Interest on all issues of senior unsecured notes is payable semi-annually in arrears.

The Partnership's senior unsecured notes and associated indenture agreements (other than the indenture for the 11¼ Notes) restrict the Partnership's ability to make distributions to unitholders in the event of default (as defined in the indentures). The indentures also restrict the Partnership's ability and the ability of certain of its subsidiaries to: (i) incur additional debt or enter into sale and leaseback transactions; (ii) pay certain distributions on or repurchase, equity interests (only if such distributions do not meet specified conditions); (iii) make certain investments; (iv) incur liens; (v) enter into transactions with affiliates; (vi) merge or consolidate with another company; and (vii) transfer and sell assets. These covenants are subject to a number of important exceptions and qualifications. If at any time when the notes are rated investment grade by both Moody's Investors Service, Inc. and Standard & Poor's Ratings Services and no Default (as defined in the indentures) has occurred and is continuing, many of such covenants will terminate and the Partnership and its subsidiaries will cease to be subject to such covenants.

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The Partnership may redeem up to 35% of the aggregate principal amount 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 6 % Notes and 5¼% Notes) of the date of the closing of such equity offering.

	Any Date Prior To	Price
7 % Notes	October 15, 2013	107.875 %
6 % Notes	February 1, 2014	106.825 %
6 % Notes	February 1, 2015	106.375 %
5¼% Notes	November 1, 2015	105.250 %

Prior to July 15, 2013, the Partnership may redeem some or all of the 11¼% Notes at a redemption price equal to 100% of their principal amount plus an applicable make-whole premium and accrued and unpaid interest to the redemption date.

The Partnership may also redeem all or part of each of the series of notes on or after the redemption dates set forth below at the price for each respective year (expressed as percentages of principal amount) plus accrued and unpaid interest and liquidation damages, if any, on the notes redeemed.

11¼% Notes Redemption Date: July 15		7 % Notes Redemption Date: October 15		6 % Notes Redemption Date: February 1		6 % Notes Redemption Date: February 1		5¼% Notes Redemption Date: November 1	
Year	Price	Year	Price	Year	Price	Year	Price	Year	Price
2013	105.625%	2014	103.938%	2016	103.438%	2017	103.188%	2017	102.625%
2014	102.813%	2015	101.969%	2017	102.292%	2018	102.125%	2018	101.750%
2015 and thereafter	100.000%	2016 and thereafter	100.000%	2018	101.146%	2019	101.063%	2019	100.875%
				2016 and thereafter	100.000%	2016 and thereafter	100.000%	2016 and thereafter	100.000%

Subsequent Event - Accounts Receivable Securitization Facility

In January 2013, the Partnership entered into an accounts receivable securitization facility (the “Securitization Facility”), that provides up to $200 million of borrowing capacity at favorable commercial paper rates through January 2014. Under this Securitization Facility, one of the Partnership’s consolidated subsidiaries (Targa Liquids Marketing and Trade LLC or “TLMT”) sells or contributes receivables to another of the Partnership’s 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, without recourse, 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 us or TLMT. Any excess receivables are eligible to satisfy the claims of creditors of us or TLMT. Total funding under this Securitization Facility in January 2013 was $171.4 million.

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Debt Re-acquisitions Summary

The debt re-acquisitions described above were reported as follows in our Consolidated Statements of Operations:

	2012	2010
Premium paid on redemption of the Partnership's of 8¼ Notes	$ (8.6)	$ -
Premium paid on redemption of TRI of 8½ Senior Notes	-	(10.9)
Write-off of deferred debt issue cost:		
Partnership 8¼ Notes	(2.5)	-
TRI 8½ Senior Notes	-	(6.5)
Loss on debt redemption	$ (11.1)	$ (17.4)
Gain on acquisition of TRC Holdco Notes	$ 0.5	$ 36.8
Write-off of deferred debt issue cost:		
TRC Holdco Notes	(0.3)	(2.0)
TRI Term Loan Facilities	-	(21.5)
TRC Revolver	(0.2)	
TRP Revolver	(1.7)	(0.8)
Gain (loss) on early debt extinguishment, net	$ (1.7)	$ 12.5

Note 11 — Partnership Units and Related Matters

Dropdown Transactions

In April 2010, we completed the sale of our interests to the Partnership in the Sand Hills and Straddle Systems for $420.0 million, effective April 1, 2010. This sale triggered a mandatory prepayment on TRI's Senior Secured Credit Agreement of $152.5 million, which was paid on April 27, 2010. As part of the closing of the sale of our Sand Hills and Straddle Systems, we amended our Omnibus Agreement with the Partnership, to continue to provide general and administrative and other services to the Partnership through April 2013.

In August 2010, we completed the sale to the Partnership of our 63% equity interest in the Versado System, effective August 1, 2010, for $247.2 million in the form of $244.7 million in cash and $2.5 million in partnership interests represented by 89,813 common units and 1,833 general partner units. The sale triggered a mandatory prepayment of $91.3 million under TRI's Senior Secured Credit Facility. In accordance with the terms of the Versado Purchase and Sale Agreement, we reimbursed the Partnership for maintenance capital expenditures required pursuant to our New Mexico Environmental Department settlement agreement. Expenditures were substantially completed by December 31, 2011, and our total share was $27.8 million.

In September 2010, we completed the sale to the Partnership of our Venice Operations, which includes Targa's 76.8% interest in Venice Energy Services Company, L.L.C. ("VESCO"), for aggregate consideration of $175.6 million, effective September 1, 2010. The sale triggered a mandatory prepayment of $73.5 million under TRI's Senior Secured Credit Facility.

The net impact of our sale of assets to the Partnership resulted in an increase to additional paid-in capital of $258.9 million and a corresponding reduction of the noncontrolling interest in these assets.

Public Offerings of Common Units

In January 2010, the Partnership completed a public offering of 6,325,000 common units (including underwriters' overallotment option) at a price of $23.14 per common unit, providing net proceeds of $140.2 million. We contributed $3.0 million to maintain our 2% general partner interest. The Partnership used the net proceeds from the offering for general partnership purposes, which included reducing borrowings under its Revolver.

In April 2010, Targa LP Inc., a wholly-owned subsidiary of ours, closed on a secondary public offering of 8,500,000 common units of the Partnership at $27.50 per common unit. Proceeds from this offering, after underwriting discounts and commission were $224.4 million before expenses associated with the offering. This offering also triggered a mandatory prepayment on our Senior Secured Credit Agreement of $3.2 million related to TRI's Senior Secured Revolving Credit Facility and $105.6 million on TRI's Senior Secured Term Loan Facility.

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In 2010, the Partnership filed with the SEC a universal shelf registration statement (the "2010 Shelf"), which provides the Partnership with the ability to offer and sell an unlimited amount of debt and equity securities, subject to market conditions and the Partnership's capital needs. The 2010 Shelf expires 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. We contributed $3.8 million to maintain our 2% general partner interest. The Partnership used the net proceeds from this offering to reduce borrowings under its 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. We contributed $6.3 million to maintain our 2% general partner interest. The Partnership used the net proceeds from the offering for general partnership purposes, which included reducing borrowings under its 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, we purchased 1,300,000 common units with an aggregate value of $49.8 million. We contributed $3.5 million to maintain our 2% general partner interest. The Partnership 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. We contributed $8.0 million to maintain our 2% general partner interest. The Partnership used the net proceeds from this offering to fund a portion of the $975 million purchase price of the Badlands acquisition.

In 2012, the Partnership filed with the SEC a universal shelf registration statement that, subject to effectiveness at the time of use, allows the Partnership to issue up to an aggregate of $300 million of debt or equity securities (the "2012 Shelf"). In August 2012, the Partnership entered into an Equity Distribution Agreement ("EDA") with Citibank pursuant to which the Partnership may sell, at its option, up to an aggregate of $100 million of its common units through Citibank, as sales agent, under the 2012 Shelf. Settlement for sales of common units will occur on the third business day following the date on which any sales were made in return for payment of the net proceeds to the Partnership. During 2012, there were no sales of common units pursuant to this program. The 2012 Shelf expires in August 2015.

Subsequent Event

In 2013, the Partnership issued 1,679,848 common units and received proceeds of $64.1 million, net of 2% commission fees, pursuant to the EDA. In addition, we contributed $1.3 million to maintain our 2% general partner interest.

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Distributions

The following table details the distributions declared and/or paid during the years ended December 31, 2012, 2011 and 2010:

		Distributions					
		Limited Partners	General Partner			Distributions to Targa Resources	Distributions per limited
Three Months Ended	Date Paid	Common	Incentive	2%	Total	Corp.	partner unit
		(In millions, except per unit amounts)					
2012							
December 31, 2012	February 14, 2013	$ 69.0	$ 20.1	$ 1.8	$ 90.9	$ 30.7	$ 0.6800
September 30, 2012	November 14, 2012	59.1	16.1	1.5	76.7	26.2	0.6625
June 30, 2012	August 14, 2012	57.3	14.4	1.5	73.2	24.2	0.6425
March 31, 2012	May 15, 2012	55.5	12.7	1.4	69.6	22.2	0.6225
2011							
December 31, 2011	February 14, 2012	$ 53.7	$ 11.0	$ 1.3	$ 66.0	$ 20.1	$ 0.6025
September 30, 2011	November 14, 2011	49.4	8.8	1.2	59.4	16.8	0.5825
June 30, 2011	August 12, 2011	48.3	7.8	1.2	57.3	15.6	0.5700
March 31, 2011	May 13, 2011	47.3	6.8	1.1	55.2	14.4	0.5575
2010							
December 31, 2010	February 14, 2011	$ 46.4	$ 6.0	$ 1.1	$ 53.5	$ 13.5	$ 0.5475
September 30, 2010	November 12, 2010	40.6	4.6	0.9	46.1	11.8	0.5375
June 30, 2010	August 13, 2010	35.9	3.5	0.8	40.2	10.4	0.5275
March 31, 2010	May 14, 2010	35.2	2.8	0.8	38.8	9.6	0.5175

Note 12 — Common Stock and Related Matters

Public Offerings

On December 10, 2010, certain of our stockholders sold, in an initial public offering (“IPO”) 18,831,250 common shares at a price of $22.00 per share. We did not receive any proceeds from the sale of shares by the selling stockholders.

On April 26, 2011, certain of our stockholders sold, in a secondary public offering, 6,497,500 common shares at a price of $31.73 per share. We did not receive any proceeds from the sale of shares by the selling stockholders.

Dividends

The following table details the dividends declared and/or paid since our IPO through December 31, 2012:

Three Months Ended	Date Paid	Total Dividend Declared	Amount of Dividend Paid	Accrued Dividends (1)	Dividend Declared per Share of Common Stock
		(In millions, except per share amounts)			
2012					
December 31, 2012	February 15, 2013	$ 19.4	$ 19.0	$ 0.4	$ 0.45750
September 30, 2012	November 15, 2012	18.0	17.3	0.7	0.42250
June 30, 2012	August 15, 2012	16.7	16.1	0.6	0.39375
March 31, 2012	May 16, 2012	15.5	15.0	0.5	0.36500
2011					
December 31, 2011	February 15, 2012	$ 14.3	$ 13.8	$ 0.5	$ 0.33625
September 30, 2011	November 15, 2011	13.0	12.6	0.4	0.30750
June 30, 2011	August 16, 2011	12.3	11.9	0.4	0.29000
March 31, 2011	May 13, 2011	11.6	11.2	0.4	0.27250
2010					
December 31, 2010	February 14, 2011	$ 2.6	$ 2.5	$ 0.1	$ 0.06160 (2)

(1) Represents accrued dividends on the restricted shares that are payable upon vesting.
(2) Represents a prorated dividend for the portion of the fourth quarter of 2010 that the Company was public.

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Note 13 — Earnings Per Common Share

Basic earnings per share are computed using the weighted average number of common shares outstanding during the period. Diluted earnings per share are computed using weighted average shares outstanding during the period, incorporated with the dilutive effect of restricted stock awards and stock options. The dilutive effect was determined through the application of the treasury method.

Prior to the conversion of the Series B Preferred Stock to common stock on December 10, 2010, net income after the impact of preferred dividends was allocated according to the preferred stock agreement. The terms of the preferred stock agreement stipulated that common shareholders are not entitled to any dividends, unless approved with written consent of a majority of the outstanding preferred stockholders, until the preferred holders recapture the carrying value of their preferred securities which includes accreted dividends. For 2010, there was no allocation to preferred shareholders as the Company was in a loss position and the preferred shareholders do not participate in losses under the terms of the preferred stock agreement.

For each of the periods presented below, all of the potentially dilutive securities were excluded from the calculation of diluted EPS as they were anti-dilutive.

	2010 (In thousands)
Restricted Stock - 2010 Stock Incentive Plan (1)	1,350.0
Restricted Stock - 2005 Incentive Compensation Plan (2)	10.6
Stock Options - 2005 Incentive Compensation Plan (3)	1,470.0
Conversion of Series B Preferred Stock (4)	33,322.5

(1) In connection with the IPO in December 2010, the Company issued 1,350,000 shares of restricted stock under the 2010 Stock Incentive Plan to employees. At December 31, 2010, all of these shares were unvested. Starting from 2011, these shares are included in the computation of diluted EPS. In 2012, 60% of the shares were vested and these vested shares were included in basic EPS calculation.

(2) Amounts represent the weighted average number of unvested shares outstanding until 2011. Upon vesting, these shares were included in basic EPS calculation.

(3) Amounts represent the weighted average number of unexercised stock options outstanding. Prior to the closing of the IPO in December 2010, all outstanding options were either exercised or cashed out. As of December 31, 2010, there are no outstanding stock options.

(4) During 2010, in connection with the closing of the IPO, 6,409,697 shares of Series B Convertible Participating Preferred Stock, plus accreted value, were converted into 35,356,698 shares of common stock. Beginning on December 10, 2010, these shares are included in the calculation of weighted average shares outstanding – basic and diluted. The amount included in the table above for 2010 represents the weighted average shares for the period from January 1, 2010 through December 9, 2010 (based on the actual number of shares converted on December 10, 2010).

In 2012 and 2011, we included all the potentially dilutive securities in the calculation of diluted EPS.

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The following table sets forth a reconciliation of net income and weighted average shares outstanding used in computing basic and diluted net income per common share:

	2012	2011	2010
Net income	$159.3	$215.4	$63.3
Less: Net income attributable to noncontrolling interests	121.2	184.7	78.3
Net income (loss) attributable to Targa Resources Corp.	38.1	30.7	(15.0)
Dividends on Series B preferred stock	-	-	(9.5)
Dividends to common equivalents	-	-	(177.8)
Net income (loss) attributable to common shareholders	$38.1	$30.7	$(202.3)
Weighted average shares outstanding - basic	41.0	41.0	6.5
Net income (loss) available per common share - basic	$0.93	$0.75	$(30.94)
Weighted average shares outstanding	41.0	41.0	6.5
Dilutive effect of unvested stock awards	0.8	0.4	-
Weighted average shares outstanding - diluted	41.8	41.4	6.5
Net income (loss) available per common share - diluted	$0.91	$0.74	$(30.94)

Note 14 — Derivative Instruments and Hedging Activities

Partnership Commodity Hedges

The primary purpose of the Partnership’s commodity risk management activities is to hedge the exposure to commodity price risk and reduce fluctuations in the Partnership’s operating cash flow despite fluctuations in commodity prices. In an effort to reduce the variability of cash flows, the Partnership has hedged the commodity price associated with a portion of its expected (i) natural gas equity volumes in Field Gathering and Processing Operations through 2015 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 through 2014 that result from its percent of proceeds processing arrangements by entering into derivative instruments including swaps and purchased puts (floors) and calls (caps). The Partnership has designated these derivative contracts as cash flow hedges.

The hedges generally match the NGL product composition and the NGL and natural gas delivery points to those of the Partnership’s 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 the Partnership’s 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. The Partnership’s natural gas and NGL hedges are settled using published index prices for delivery at various locations which closely approximate the Partnership’s actual natural gas and NGL delivery points.

The Partnership hedges a portion of its condensate sales using crude oil hedges that are based on the NYMEX futures contracts for West Texas Intermediate light, sweet crude, which approximates the prices received for condensate. This necessarily exposes the Partnership to a market differential risk if the NYMEX futures do not move in exact parity with the sales price of its underlying West Texas condensate equity volumes.

At December 31, 2012, the notional volumes of the Partnership’s commodity hedges for equity volumes were:

Commodity	Instrument	Unit	2013	2014	2015
Natural Gas	Swaps	MMBtu/d	26,089	18,000	4,500
NGL	Swaps	Bbl/d	5,650	1,000	-
Condensate	Swaps	Bbl/d	1,795	700	-

The Partnership also enters into derivative instruments to help manage other short-term commodity-related business risks. The Partnership has not designated these derivatives as hedges and records changes in fair value and cash settlements to revenues.

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The following schedules reflect the fair values of the Partnership's derivative instruments:

	Derivative Assets			Derivative Liabilities		
	Balance Sheet Location	Fair Value as of December 31, 2012	2011	Balance Sheet Location	Fair Value as of December 31, 2012	2011
Derivatives designated as hedging instruments						
Commodity contracts	Current assets	$29.2	$40.3	Current liabilities	$ 7.2	$ 40.6
	Long-term assets	5.1	10.9	Long-term liabilities	4.8	15.8
Total derivatives designated as hedging instruments		$34.3	$51.2		$ 12.0	$ 56.4
Derivatives not designated as hedging instruments						
Commodity contracts	Current assets	$0.1	$0.7	Current liabilities	$ 0.2	$ 0.5
Total derivatives not designated as hedging instruments		$0.1	$0.7		$ 0.2	$ 0.5
Total derivatives		$34.4	$51.9		$ 12.2	$ 56.9

The fair value of the Partnership's 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 the Partnership's derivative instruments was a net asset of $22.2 million as of December 31, 2012, net of an adjustment for credit risk. The credit risk adjustment is based on the default probabilities by year as indicated by market quotes for the counterparties' credit default swap rates. These default probabilities have been applied to the unadjusted fair values of the derivative instruments to arrive at the credit risk adjustment, which was immaterial for all periods presented.

The Partnership's payment obligations in connection with substantially all of these hedging transactions and any additional credit exposure due to a rise in natural gas, NGL and crude oil prices relative to the fixed prices set forth in the hedges are secured by a first priority lien in the collateral securing its senior secured indebtedness that ranks equal in right of payment with liens granted in favor of its senior secured lenders.

The following tables reflect amounts recorded in other comprehensive income ("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) 2012	2011	2010
Interest rate contracts	$-	$(4.3)	$(20.1)
Commodity contracts	76.8	(33.6)	52.7
	$76.8	$(37.9)	$32.6

Gain (Loss) Reclassified from OCI into Income

	(Effective Portion)		
Location of Gain (Loss)	2012	2011	2010
Interest expense, net	$(7.9)	$(8.1)	$(9.2)
Revenues	46.0	(30.3)	8.7
	$38.1	$(38.4)	$(0.5)

Hedge ineffectiveness was immaterial for all periods presented.

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Our consolidated earnings are also affected by the Partnership's 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. The Partnership recorded the following mark-to-market gains (losses) for the periods indicated:

Derivatives Not Designated as Hedging Instruments	Location of Gain Recognized in Income on Derivatives	Gain (Loss) Recognized in Income on Derivatives 2012	2011	2010
Commodity contracts	Revenue	$ 0.7	$ 1.7	$ (1.0)
Commodity contracts	Other income (expense)	-	-	(0.4)
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 2015:

	December 31, 2012	December 31, 2011
Commodity hedges, before tax	$ 3.2	$ 0.4
Commodity hedges, after tax	1.9	0.2
Interest rate swaps, before tax	(1.2)	(2.5)
Interest rate swaps, after tax	(0.7)	(1.4)

As of December 31, 2012, deferred net gains of $22.8 million on commodity hedges and deferred net losses of $6.1 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 15 for additional disclosures related to derivative instruments and hedging activities.

Note 15 — Fair Value Measurements

Under generally accepted accounting principles, our consolidated balance sheet reflects 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.

Following is additional qualitative and quantitative disclosures regarding fair value measurements of financial instruments.

Fair Value of Derivative Financial Instruments

The Partnership's derivative instruments consist of financially settled commodity swap and option contracts and fixed price commodity contracts with certain counterparties. The Partnership determines the fair value of its 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. The Partnership has consistently applied these valuation techniques in all periods presented and believe the Partnership has obtained the most accurate information available for the types of derivative contracts the Partnership holds.

The fair values of the Partnership's derivative instruments, which aggregate to a net asset position of $22.2 million as of December 31, 2012, are sensitive to changes in forward pricing on natural gas, NGLs and crude oil. This asset position reflects the present value, adjusted for counterparty credit risk, of the amount the Partnership expects to receive in the future on its 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 $1.8 million, ignoring an adjustment for counterparty credit risk. If forward pricing on natural gas, NGLs and crude oil were to decrease by 10%, the result would be a fair value reflecting a net asset of $46.2 million, ignoring an adjustment for counterparty credit risk.

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Fair Value of Other Financial Instruments

Due to their cash or near-cash nature, the carrying value of other financial instruments included in working capital (i.e., cash and cash equivalents, accounts receivable, accounts payable) approximates their fair value. 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:

- Holdco facility is based on repurchases we made in December 2010;
- senior secured revolving credit facilities are based on carrying value which approximates fair value as its interest rate is based on prevailing market rates;
- 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 sheet at fair value and (2) supplemental fair value disclosures for other financial instruments:

	December 31, 2012				
		Fair Value			
	Carrying Value	Total	Level 1	Level 2	Level 3
Financial Instruments Recorded on Our Consolidated Balance Sheet at Fair Value:					
Assets from commodity derivative contracts	$34.3	$34.3	$-	$34.3	$-
Liabilities from commodity derivative contracts	12.1	12.1	-	11.5	0.6
Badlands contingent consideration liability (see Note 4)	15.3	15.3	-	-	15.3
Financial Instruments Recorded on Our Consolidated Balance Sheet at Carrying Value:					
Cash and cash equivalents	76.3	76.3			
TRC Senior secured revolving credit facility	82.0	82.0	-	82.0	-
Partnership's Senior secured revolving credit facility	620.0	620.0	-	620.0	-

Partnership's Senior unsecured notes	1,773.3	1,945.2	-	1,945.2	-

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		December 31, 2011			
		Fair Value			
	Carrying Value	Total	Level 1	Level 2	Level 3
Financial Instruments Recorded on Our Consolidated Balance Sheet at Fair Value:					
Assets from commodity derivative contracts	$51.9	$51.9	$-	$51.9	$-
Liabilities from commodity derivative contracts	56.9	56.9	-	56.9	-
Financial Instruments Recorded on Our Consolidated Balance Sheet at Carrying Value:					
Cash and cash equivalents	145.8	145.8			
Holdco loan facility	89.3	87.5	-	-	87.5
Partnership's Senior secured revolving credit facility	498.0	498.0	-	498.0	-
Partnership's Senior unsecured notes	979.7	1,057.3	-	1,057.3	-

Additional Information Regarding Level 3 Fair Value Measurements

As of December 31, 2012, we reported certain of the Partnership’s 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, 2012, the Partnership has two 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 curve beginning in year 2015, and the forward natural gas basis curve for the South Texas Natural Gas Pipeline beginning in January 2013. Because a significant portion of the derivative’s term is in 2015 and beyond, for the former, and in calendar year 2013, for the latter, both valuations are categorized as Level 3. 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.

As of December 31, 2012, the Partnership has a $15.3 million liability which represents the fair value of contingent consideration included in the preliminary valuation of the Badlands acquisition (see Note 4). The preliminary fair value was determined by a probability based model measuring the likelihood of meeting certain volumetric measures identified in the Membership Interest Purchase and Sale Agreement. Consequently, as these probability based inputs are not observable, the entire valuation of the contingent consideration is categorized in Level 3.

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The following table sets forth a reconciliation of the changes in the fair value of our and the Partnership's financial instruments classified as Level 3 in the fair value hierarchy:

	Commodity Derivative Contracts	Long-term Debt	Contingent Liability
Balance, December 31, 2009	$(13.7)	$ 278.9	$-
Debt extinguishment	-	(214.3)	-
Change in fair value	-	22.2	-
Unrealized losses included in OCI	2.6	-	-
Settlements included in Revenue	(0.5)	-	-
Balance, December 31, 2010	(11.6)	86.8	-
Change in fair value	-	0.7	-
Settlements included in Revenue	3.7	-	-
Transfers out of Level 3	7.9	-	-
Balance, December 31, 2011	-	87.5	-
Issuances	-	-	15.3
Loss (gain) included in Revenue	(0.1)	-	-
Unrealized losses included in OCI	0.7	-	-
Debt extinguishment	-	(87.5)	-
Balance, December 31, 2012	$0.6	$ -	$15.3

During 2011, we transferred $7.9 million in Partnership 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 the Partnership's derivative contracts and reclassified these instruments as Level 2.

There were no transfers of assets or liabilities among the three levels of the fair value hierarchy during 2010 or 2012.

The amount of gains for the period included in earnings is attributable to the change in unrealized gains related to assets or liabilities held at the reporting date.

Note 16 — Related Party Transactions

Transactions with Unconsolidated Affiliate

For the years 2012, 2011 and 2010, transactions with GCF included in revenues were $0.1 million, $0.8 million and $0.3 million. For the same periods, transactions with GCF included in costs and expenses were $1.9 million, $0.4 million and $1.1 million. These transactions were at market prices consistent with similar transactions with other nonaffiliated entities.

Relationship with SAJET Resources LLC

Former holders of our Class A Common units, including Warburg Pincus and 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. We provide general and administrative services to SAJET and are reimbursed for these amounts. During 2012, we were reimbursed $1.3 million for such services provided. Additionally, on December 1, 2012, Targa Midstream Services LLC purchased six 90,000 gallon propane storage tanks from SAJET for $1.2 million. This transaction was at a market price consistent with similar transactions with other nonaffiliated entities.

Relationship with Warburg Pincus LLC

Affiliates of Warburg Pincus beneficially own approximately 11.1% of our outstanding common stock. Accordingly, Warburg Pincus can exert significant influence over us and any action requiring the approval of the holders of our stock, including the election of directors and approval of significant corporate transactions. Warburg's concentrated ownership makes it less likely that any other holder or group of holders of common stock will be able to affect the way we are managed or the direction of our business.

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Peter Kagan and In Sean Hwang, two of our directors, are Managing Directors of Warburg Pincus LLC and are also directors of Broad Oak Energy, Inc. ("Broad Oak"), from whom the Partnership buys natural gas and NGL products. Mr. Kagan is also a director of Laredo Petroleum Holdings Inc. ("Laredo") from whom the Partnership buys natural gas and NGL products. Affiliates of Warburg Pincus LLC own a controlling interest in Broad Oak and Laredo.

The following table shows the transactions with each of these related parties.

	Purchases		
	2012	2011	2010
Broad Oak	$ -	$ 71.3	$ 41.5
Laredo	88.1	34.1	-

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

Note 17 — Commitments and Contingencies

Future non-cancelable commitments related to certain contractual obligations are presented below in aggregate and for each of the next five fiscal years. The below amounts represent those that were fixed and determinable as of December 31, 2012.

	In Aggregate	2013	2014	2015	2016	2017
Non-Partnership obligations:						
Operating lease (1)	$ 1.2	$ 0.3	$ 0.3	$ 0.3	$ 0.3	$ -
Partnership obligations:						
Operating lease and service contract (2)	37.1	6.5	5.9	5.7	5.3	4.0
Pipeline capacity and throughput agreements (3)	191.1	22.5	18.6	18.4	18.4	18.0
Land site lease and right-of-way (4)	7.3	1.6	1.5	1.4	1.4	1.4
	$ 236.7	$ 30.9	$ 26.3	$ 25.8	$ 25.4	$ 23.4

(1) Includes minimum payments on lease obligation for corporate office space.
(2) Includes minimum payments on lease obligations for office space, railcars and tractors, and service contracts.
(3) Consists of pipeline capacity payments for firm transportation contracts and throughput and deficiency agreements.
(4) Land site lease and right-of-way provides for surface and underground access for gathering, processing and distribution assets that are located on property not owned by the Partnership. These agreements expire at various dates through 2099.

Total actual expenses related to the above non-cancelable commitments were:

	2012	2011	2010
Non-Partnership:			
Operating leases	$ 2.1	$ 2.0	$ 2.1
Partnership:			
Operating leases	16.1	14.2	13.9
Pipeline capacity and throughput agreement payments	15.4	12.4	8.6

Land site lease and right-of-way	3.3	2.8	2.8

Environmental

For environmental matters, we record liabilities when remedial efforts are probable and the costs can be reasonably estimated. Environmental reserves do not reflect management’s assessment of any insurance coverage that may be applicable to the matters at issue. Management has assessed each of the matters based on current information and made a judgment concerning its potential outcome, considering the nature of the claim, the amount and nature of damages sought and the probability of success.

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The Partnership's environmental liabilities were not significant as of December 31, 2012.

We have reimbursed the Partnership for maintenance capital expenditures totaling $16.8 million as of December 31, 2012, 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 the Versado Gas Processors, LLC joint venture, with $1.1 million reimbursed during the year ended December 31, 2012. These capital projects are substantially complete.

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 18 – Significant Risks and Uncertainties

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

Nature of the Partnership's Operations in Midstream Energy Industry

The Partnership operates in the midstream energy industry. Its business activities include gathering, processing, fractionating and storage of natural gas, NGLs and crude oil. The Partnership's 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.

The Partnership's 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 the Partnership's 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 the Partnership receives 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 the Partnership's control.

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In an effort to reduce the variability of our cash flows, the Partnership has hedged the commodity price associated with a significant portion of its expected natural gas equity volumes through 2015 and its NGL and condensate equity volumes through 2014 by entering into derivative financial instruments including swaps and purchased puts (or floors). The Partnership hedges a higher percentage of its expected equity volumes in the current year as compared to future years where the volume forecasting risk is greater. With swaps, the Partnership typically receives an agreed upon fixed price for a specified notional quantity of natural gas or NGL and pays the hedge counterparty a floating price for that same quantity based upon published index prices. Since the Partnership receives from its 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, the Partnership typically limits its use of swaps to hedge the prices of less than its expected natural gas and NGL equity volumes. The Partnership utilizes purchased puts (or floors) to hedge additional expected equity commodity volumes without creating volumetric risk. The Partnership's commodity hedges may expose it 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 14.

Interest Rate Risk

We and the Partnership are exposed to changes in interest rates, primarily as a result of variable rate borrowings under our and the Partnership's credit facilities.

Counterparty Risk – Credit and Concentration

Derivative Counterparty Risk

Where the Partnership is 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.

The Partnership has master netting provisions in the International Swap Dealers Association agreements with all of its derivative counterparties. These netting provisions allow the Partnership to net settle asset and liability positions with the same counterparties, and would reduce its maximum loss due to counterparty credit risk by $8.9 million as of December 31, 2012. The range of losses attributable to the Partnership's individual counterparties would be between $0.8 and $5.6 million, depending on the counterparty in default.

The credit exposure related to commodity derivative instruments is represented by the fair value of contracts with a net positive fair value, representing expected future receipts, at the reporting date. At such times, these outstanding instruments expose the Partnership to losses in the event of nonperformance by the counterparties to the agreements. Should the creditworthiness of one or more of the counterparties decline, the ability to mitigate nonperformance risk is limited to a counterparty agreeing to either a voluntary termination and subsequent cash settlement or a novation of the derivative contract to a third party. In the event of a counterparty default, the Partnership may sustain a loss and its cash receipts could be negatively impacted.

As of December 31, 2012, affiliates of Wells Fargo Bank N.A. ("Wells Fargo"), Barclays PLC ("Barclays"), Securities Americas LLC ("Natixis"), Credit Suisse Group AG ("Credit Suisse") and Bank of America Merrill Lynch ("BAML") accounted for 31%, 16%, 15%, 11% and 10% of the Partnership's counterparty credit exposure related to commodity derivative instruments. Wells Fargo, Barclays, Natixis, Credit Suisse and BAML 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:

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	2012	2011	2010
Balance at beginning of year	$ 2.4	$ 7.9	$ 8.0
Additions	-	0.5	-
Deductions	(1.5)	(6.0)	(0.1)
Balance at end of year	$ 0.9	$ 2.4	$ 7.9

Significant Commercial Relationships

The following customer accounted for more than 10% of our consolidated revenues for the periods indicated:

	2012	2011	2010
% of consolidated revenues			
Chevron Phillips Chemical Company LLC	10 %	12 %	10 %

All transactions in the above table were associated with the Marketing and Distribution segment.

Casualty or Other Risks

We maintain coverage in various insurance programs, which provides us and the Partnership with property damage, business interruption and other coverages which are customary for the nature and scope of our operations.

Management believes that we have adequate insurance coverage, although insurance will 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, we may not be able to renew existing insurance policies or procure other desirable insurance on commercially reasonable terms, if at all.

If we or the Partnership 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 the Partnership, or which causes us or the Partnership to make significant expenditures not covered by insurance, could reduce our or the Partnership's ability to meet our financial obligations.

Note 19 – Other Operating Income

	2012	2011	2010
Loss (gain) on sale of assets	$ 15.6 (1)	$ 0.2	$ (1.4)
Casualty loss (gain) adjustment	3.6	-	(3.3)
Miscellaneous tax expense	0.7	-	-
	$ 19.9	$ 0.2	$ (4.7)

(1) Reflects a $15.4 million loss due to a write-off of the Partnership's investment in the Yscloskey joint interest processing plant in Southeastern Louisiana. Following hurricane Isaac, the joint venture owners elected not to restart the plant.

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Note 20—Income Taxes

Our provisions for income taxes for the periods indicated are as follows:

	2012	2011	2010
Current expense (benefit)	$ 27.9	$ 14.3	$ (10.6)
Deferred expense	9.0	12.3	33.1
	$ 36.9	$ 26.6	$ 22.5

Our deferred income tax assets and liabilities at December 31, 2012 and 2011 consist of differences related to the timing of recognition of certain types of costs as follows:

	2012	2011
Deferred tax assets:		
Net operating loss	$ -	$ -
Other	3.5	3.5
Deferred tax assets before valuation allowance	3.5	3.5
Valuation allowance	(3.5)	(3.5)
	-	-
Deferred tax liabilities:		
Investments (1)	(99.8)	(95.5)
Risk management contracts	(12.8)	(9.8)
Property, Plant and Equipment	(11.7)	(13.8)
Other	(10.6)	(4.8)
	(134.9)	(123.9)
Net deferred tax liability	$ (134.9)	$ (123.9)
Federal	$ (120.1)	$ (115.6)
Foreign	0.6	0.6
State	(15.4)	(8.9)
	$ (134.9)	$ (123.9)
Balance sheet classification of deferred tax assets (liabilities):		
Current asset	$ -	$ 0.1
Long-term asset	(3.5)	(3.5)
Current liability	(0.2)	-
Long-term liability	(131.2)	(120.5)
	$ (134.9)	$ (123.9)

(1) Our deferred tax liability attributable to investments reflects the differences between the book and tax carrying values of the assets and liabilities of our equity method investments.

As a result of dropdown transactions in 2010 and 2009, differences related to the date of income recognition for book and tax occurred. While these are timing differences, the reversal of these differences will not be recognized until we sell the units of the Partnership. Therefore, the tax effect of these differences is recorded as a valuation allowance of $3.5 million in deferred taxes, as a component of other long term assets for 2010.

As of December 31, 2010, for federal income tax purposes, both regular tax net operating losses (“NOLs”) and alternative minimum tax NOLs were fully utilized.

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Set forth below is the reconciliation between our income tax provision (benefit) computed at the United States statutory rate on income before income taxes and the income tax provision in the accompanying consolidated statements of operations for the periods indicated:

Income tax reconciliation:	2012	2011	2010
Income before income taxes	$196.2	$242.0	$85.8
Less: Net income attributable to noncontrolling interest	(121.2)	(184.7)	(78.3)
Less: Income taxes included in noncontrolling interest	(3.5)	(3.6)	(3.1)
Income attributable to TRC before income taxes	71.5	53.7	4.4
Federal statutory income tax rate	35 %	35 %	35 %
Provision for federal income taxes	25.0	18.8	1.5
State income taxes, net of federal tax benefit (1)	6.8	2.6	13.4
Valuation allowance	-	-	3.0
Amortization of deferred charge on 2010 transactions	4.7	4.7	3.0
Other, net	0.4	0.5	1.6
Income Tax Provision	$36.9	$26.6	$22.5

(1) For 2010, primarily consists of the write-off of an $11.9 million Texas margin tax credit.

We have not identified any uncertain tax positions. We believe that our income tax filing positions and deductions will be sustained on audit and do not anticipate any adjustments that will result in a material adverse effect on our financial condition, results of operations or cash flow. Therefore, no reserves for uncertain income tax positions have been recorded.

In April 2010, we closed on a secondary public offering of 8,500,000 common units of the Partnership. The direct tax effect of the change in ownership interest in the Partnership as a result of the secondary public offering was recorded as a reduction in shareholders' equity of $79.1 million, an increase in current tax liability of $41.9 million and an increase in deferred tax liability of $37.2 million. A 2010 return to provision adjustment resulted in an increase in current tax liability of $0.8 million and a decrease in deferred tax liability of $0.8 million. There was no tax impact on consolidated net income as a result of the secondary public offering.

In April 2010, we sold our interests in the Sand Hills and Straddle Systems to the Partnership. On September 28, 2010, we sold our interests in the Venice Operations to the Partnership. Under applicable accounting principles, the tax consequences of transactions with common control entities are not to be reflected in pre-tax income. Consequently, there was no tax impact on consolidated pre-tax net income as a result of the sale of the Sand Hills and Straddle Systems and the Venice Operations. The tax effect of these sales was recorded as an increase in other long term assets of $64.7 million, to be amortized over the remaining life of the underlying assets, an increase in current tax liability of $94.9 million, a decrease in deferred tax liability of $27.5 million and an increase in current tax expense of $2.7 million. A 2010 return to provision adjustment resulted in an increase in current tax liability of $0.7 million and a decrease in deferred tax liability of $0.7 million.

Note 21 — Supplemental Cash Flow Information

Supplemental cash flow information was as follows for the periods indicated:

	2012	2011	2010
Cash:			
Interest paid, net of capitalized interest	$95.6	$96.1	$89.5

Income taxes paid, net of refunds	30.5	33.8	92.7
Non-cash:			
Inventory line-fill transferred to property, plant and equipment	3.0	0.7	0.4
Accrued dividends on unvested equity awards	2.7	1.4	-
Badlands acquisition contingent consideration	15.3	-	-
Paid-in-kind interest refinanced to Holdco principal	-	-	10.9
Conversion of Series B preferred Stock (accretive value)	-	-	79.9
Distribution of property to common shareholders	-	-	3.2

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Note 22 – Stock and Other Compensation Plans

2005 TRC Incentive Compensation Plan

Under Our 2005 Incentive Compensation Plan (“2005 Plan”), we provided restricted stock and stock options to our employees, directors and consultants.

Concurrent with our IPO in December 2010, unexercised in-the-money stock options were cashed out, resulting in $1.2 million of additional compensation expense in 2010. Unexercised out-of-the-money stock options were rescinded. As such, we had no outstanding 2005 Plan stock options at December 31, 2010. Further, all vested restricted common shares awarded under the 2005 Plan were converted to unrestricted common stock concurrent with the IPO.

2010 TRC Stock Incentive Plan

In December 2010, we adopted the Targa Resources Corp. 2010 Stock Incentive Plan (“TRC Plan”) for employees, consultants and non-employee directors of the Company. The TRC Plan allows for the grant of (i) incentive stock options qualified as such under U.S. federal income tax laws (“Incentive Options”), (ii) stock options that do not qualify as incentive options (“Non-statutory Options,” and together with Incentive Options, “Options”), (iii) stock appreciation rights (“SARs”) granted in conjunction with Options or Phantom Stock Awards, (iv) restricted stock awards (“Restricted Stock Awards”), (v) phantom stock awards (“Phantom Stock Awards”), (vi) bonus stock awards, (vii) performance unit awards, or (viii) any combination of such awards (collectively referred to a “Awards”).

Restricted Stock - Total shares authorized under this plan are 5,000,000. 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, 2009	-	$ -
Granted (1)	1,350,000	22.00
Outstanding at December 31, 2010	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

(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 2012 were 60% of the awards issued in conjunction with our IPO, net of forfeitures. The remaining 40% of awards will be vested in 2013. We repurchased 197,731 from employees at $47.88 per share 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.

Bonus Stock

On December 6, 2010, we granted 556,514 bonus stock awards to our executive management team which vested upon the closing of our IPO on December 10, 2010.

Director grants

On February 17, 2011, the compensation committee (the “Committee”) awarded 24,250 shares of our stock to our outside directors. The awards vested at the grant date.

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Subsequent Events

On January 15, 2013, the Committee made restricted stock awards of 29,123 to executive management under the TRC Plan for the 2013 compensation cycle that will cliff vest in three years from the grant date. On the same day, the Committee also awarded 7,460 shares of our stock to our outside directors (1,492 shares of common stock to each non-management director). The awards vested at the grant date.

Long-Term Incentive Plans

Performance Units

In 2007 both we and the Partnership adopted Long-Term Incentive Plans ("LTIP") for employees, consultants, directors and non-employee directors of us and our affiliates who perform services for us or our affiliates. The performance units granted under these plans are linked to the performance of the Partnership's 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 of the Targa Board of Directors. Total units authorized under the LTIPs are 1,680,000.

Each performance unit will entitle the grantee to the value of a Partnership common unit on the vesting date multiplied by the vesting percentage determined from the Partnership's ranking in a defined peer group. Currently, the performance period of the awards is three years. 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. We have used a Monte Carlo simulation model to estimate accruals throughout the vesting period. In 2012, we 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 the implied volatility because it provides a more reliable indication of future volatility.

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TRC LTIP -- Cash-settled Performance Units

The following table summarizes the cash-settled performance units for the year ended 2012 awarded under the Targa LTIP.

	Program Year				
	2009 Plan	2010 Plan	2011 Plan	2012 Plan	Total
Units outstanding January 1, 2012	526,000	307,053	119,880	-	952,933
Granted	-	1,000	3,600	140,820	145,420
Vested and paid	(524,400)	-	-	-	(524,400)
Forfeited	(1,600)	(1,800)	(930)	-	(4,330)
Units outstanding December 31, 2012	-	306,253	122,550	140,820	569,623
Calculated fair market value as of December 31, 2012		$17.5	$5.5	$5.4	$28.4
Current liability		$14.6	$-	$-	$14.6
Long-term liability		-	2.6	0.7	3.3
Liability as of December 31, 2012		$14.6	$2.6	$0.7	$17.9
To be recognized in future periods		$2.9	$2.9	$4.7	$10.5
Vesting date		June 2013	June 2014	June 2015	

The remaining weighted average recognition period for the unrecognized compensation cost is approximately 1.7 years.

Partnership LTIP – Equity-Settled Performance Units

The Partnership started issuing equity-settled performance units in 2011. The following table summarized activities of our equity-settled performance units for the years ended December 31, 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

Subsequent Event. On January 15, 2013, the Committee made awards to the executive management for the 2013 compensation cycle of 124,778 equity-settled performance units under the Partnership LITP that will vest in June 2016.

Partnership Director Grants

In 2012 and 2011, the common units granted to the Partnership's non-management directors were vested immediately at the grant date. The awards granted before 2011 will settle with the delivery of common units and are subject to three-year vesting, without a performance condition, and will vest ratably on each anniversary of the grant date. The Partnership estimates that the remaining fair value of an immaterial amount will be recognized in expense during the next year.

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The following table summarizes activity of the common unit-based awards granted to the Partnership and our Directors for the years ended December 31, 2012, 2011 and 2010 (in units and dollars):

	Number of units	Weighted Average Grant-Date Fair Value
Outstanding at December 31, 2009	41,993	$ 12.88
Granted	15,750	23.51
Vested and paid	(18,669)	15.06
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

Subsequent Event

On January 15, 2013, the Committee made awards of 10,650 of our common units (2,130 units to each of our non-management directors). On February 7, 2013, 2,130 common units were awarded to a new non-management director. The awards vested immediately at the grant date.

The following table summarizes the compensation expenses under the various compensation plans recognized for the years indicated.

	2012	2011	2010
2005 TRC Incentive Compensation Plan - Stock Options (1)	$-	$-	$0.2
2005 TRC Incentive Compensation Plan - Restricted Stocks (1)	-	-	0.2
2010 TRC stock Incentive Plan - Restricted Stock (1)	13.7	13.4	1.1
2010 TRC stock Incentive Plan - Bonus Stock (1)	-	-	12.2
2010 TRC stock Incentive Plan - Director Grants	0.4	0.8	-
TRC LTIP - Cash-settled Performance Units (1)	14.2	13.3	13.9
Partnership LTIP - Equity-settled Performance Units	3.1	1.0	-
Partnership Director Grants	0.5	0.5	0.4

(1) The compensation expenses are recognized by us and allocated to the Partnership under the provisions of the Omnibus Agreement.

The table below summarizes the unrecognized compensation expenses and the approximate remaining weighed average vesting periods related to our various compensation plans as of December 31, 2012.

	December 31, 2012	Weighted Average Remaining Vesting Period

	(In millions)	(In years)
Partnership LTIP Equity-Settled Performance Units	$8.4	2.2
2010 TRC Stock Incentive Plan - Restricted Stocks	8.0	1.6

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The total fair values of share-based awards on the dates they vested are as follows.

	2012	2011	2010
TRC LTIP - Cash-Settled performance units	$22.2	$5.5	$9.1
Partnership Director Grants	1.0	1.0	0.5
2005 TRC Incentive Compensation Plan - Restricted Stocks	-	-	0.3
2010 TRC Stock Incentive Plan - Restricted Stock (1)	40.3	-	-

(1) We recognized $1.3 million tax benefit associated with the vesting of 60% of the restricted stock related to our IPO.

401(k) Plan

We have a 401(k) plan whereby we match 100% of up to 5% of an employee's contribution (subject to certain limitations in the plan). We also contribute an amount equal to 3% of each employee's eligible compensation to the plan as a retirement contribution and may make additional contributions at our sole discretion. All Targa contributions are made 100% in cash. We made contributions to the 401(k) plan totaling $8.7 million, $7.8 million, and $7.2 million during 2012, 2011, and 2010.

Note 23 — Segment Information

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

The Partnership's Gathering and Processing division includes assets used in the gathering of natural gas produced from oil and gas wells and processing this raw natural gas into merchantable natural gas by extracting NGLs and removing impurities. 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 includes 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.

The Partnership's Logistics and Marketing division is also referred to as the Downstream Business. The 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 the Partnership's other operations, as well as transporting natural gas and NGLs.

The Partnership's Logistics Assets segment is involved in transporting, storing and fractionating mixed NGLs; storing, terminaling and transporting finished NGLs; and storing and terminaling refined petroleum products and crude oil. These assets are generally connected to, and supplied in part by, the Partnership's Gathering and Processing segments and are predominantly located in Mont Belvieu, Texas and Southwestern Louisiana. This segment includes the activities associated with the Partnership's 2011 acquisitions of refined petroleum products and crude oil storage and terminaling facilities.

The Partnership's Marketing and Distribution segment covers activities required to distribute and market raw and finished NGLs and all natural gas marketing activities. It includes (1) marketing the Partnership's own NGL production and purchasing NGL products 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; and (4) marketing natural gas available to the Partnership from its Gathering and Processing division and the purchase and resale and other value added activities related to third-party natural gas in selected United States markets.

Other contains the results of the Partnership's commodity hedging activities included in operating margin. Eliminations of inter-segment transactions are reflected in the corporate and eliminations column.

Segment information is shown in the following tables. We have segregated the following segment information between Partnership and non-Partnership activities. Partnership activities have been presented on a common control accounting basis which reflects the dropdown transactions between us and the Partnership as if they occurred in prior periods similar to a pooling of interests. The non-Partnership results include activities related to certain assets and liabilities contractually excluded from the dropdown transactions and certain historical hedge activities that could not be reflected under GAAP in the Partnership common control results.

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	2012							
	Partnership							
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	TRC Non-Partnership	Consolidated
Revenues								
Sales of commodities	$172.7	$ 240.6	$184.4	$ 4,890.2	$41.1	$ -	$ 2.1	$ 5,531.1
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)	2.1	5,885.7
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)	$ 2.1	$ 5,885.7
Operating margin	$231.2	$ 115.1	$188.3	$ 116.0	$41.1	$ -	$ 1.9	$ 693.6
Other financial information:								
Total assets (1)	$2,797.9	$ 414.1	$1,100.9	$ 548.6	$34.4	$ 129.8	$ 79.3	$ 5,105.0
Capital expenditures	$222.1	$ 9.4	$359.0	$ 12.3	$-	$ 13.9	$ 0.3	$ 617.0
Business acquisitions	$970.4	$ 25.8	$-	$ -	$-	$ -	$ -	$ 996.2

(1) The Partnership recorded a $15.4 million loss in Other Operating (Income) Expense due to a write-off of its investment in the Yscloskey joint venture interest processing plant in Southern Louisiana included in the Coastal Gathering and Processing segment. Following Hurricane Isaac, the joint venture owners elected not to restart the plant.

	2011							
	Partnership							
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	TRC Non-Partnership	Consolidated
Revenues								
Sales of commodities	$184.9	$ 325.7	$43.2	$ 6,209.9	$(37.6)	$ -	$ 4.4	$ 6,730.5
Fees from midstream services	27.5	19.8	130.0	83.8	-	(0.1)	-	261.0
	-	-	-	-	-	-	3.0	3.0

Business interruption insurance								
	212.4	345.5	173.2	6,293.7	(37.6)	(0.1)	7.4	6,994.5
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)	$ 7.4	$ 6,994.5
Operating margin	$287.9	$ 174.3	$123.1	$ 113.4	$(37.6)	$ -	$ 7.3	$ 668.4
Other financial information:								
Total assets	$1,666.2	$ 427.5	$775.4	$ 650.5	$51.9	$ 86.5	$ 173.0	$ 3,831.0
Capital expenditures	$167.5	$ 12.8	$147.4	$ 3.5	$-	$ 2.3	$ 2.2	$ 335.7
Business acquisitions	$-	$ -	$156.5	$ -	$-	$ -	$ -	$ 156.5

	2010							
	Partnership							
	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	Corporate and Eliminations	TRC Non-Partnership	Consolidated
Revenues								
Sales of commodities	$188.7	$ 432.2	$-	$ 4,663.2	$4.0	$ 0.1	$ 3.0	$ 5,291.2
Fees from midstream services	22.9	14.4	84.5	57.1	-	(0.1)	0.1	178.9
Business interruption insurance	-	-	-	-	-	-	6.0	6.0
	211.6	446.6	84.5	4,720.3	4.0	-	9.1	5,476.1
Intersegment revenues								
Sales of commodities	1,083.2	753.7	0.8	492.3	-	(2,330.0)	-	-
Fees from midstream services	1.2	2.0	86.3	24.9	-	(114.4)	-	-
	1,084.4	755.7	87.1	517.2	-	(2,444.4)	-	-
Revenues	$1,296.0	$ 1,202.3	$171.6	$ 5,237.5	$4.0	$ (2,444.4)	$ 9.1	$ 5,476.1
Operating margin	$236.6	$ 107.8	$83.8	$ 80.5	$4.0	$ -	$ 8.6	$ 521.3
Other financial information:								
Total assets	$1,623.4	$ 451.5	$471.9	$ 519.9	$44.1	$ 75.6	$ 207.4	$ 3,393.8
Capital expenditures	$67.9	$ 8.8	$66.3	$ 2.2	$-	$ -	$ 3.4	$ 148.6

The following table shows our consolidated revenues by product and service for the periods presented:

	2012	2011	2010
Sales of commodities			
Natural gas sales	$926.9	$1,120.7	$1,075.6
NGL sales	4,265.7	5,496.9	4,111.4
Condensate sales	114.1	103.0	95.1
Petroleum products	180.1	43.1	-
Derivative activities	44.3	(33.2)	9.1
	5,531.1	6,730.5	5,291.2
Fees from midstream services			
Fractionating and treating fees	115.6	86.7	55.7
Storage, terminaling, transportation and export fees	159.2	110.4	75.6
Gas processing fees	45.0	33.1	32.2
Other	34.8	30.8	15.4
	354.6	261.0	178.9
Business interruption insurance	-	3.0	6.0
Total revenues	$5,885.7	$6,994.5	$5,476.1

The following table shows a reconciliation of operating margin to net income for the periods presented:

	2012	2011	2010
Reconciliation of operating margin to net income			
Operating margin	$693.6	$668.4	$521.3
Depreciation and amortization expense	(197.6)	(181.0)	(185.5)
General and administrative expense	(139.8)	(136.1)	(144.4)
Interest expense, net	(120.8)	(111.7)	(110.9)
Income tax expense	(36.9)	(26.6)	(22.5)
Other, net	(39.2)	2.4	5.3
Net income	$159.3	$215.4	$63.3

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Note 24—Selected Quarterly Financial Data (Unaudited)

Our results of operations by quarter for the years ended December 31, 2012 and 2011 were as follows:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
	(In millions, except per share amounts)				
2012					
Revenues	$1,645.8	$1,319.1	$1,393.5	$1,527.3	$5,885.7
Gross margin	261.6	244.5	240.5	260.1	1,006.7
Operating income	107.7	83.2	59.0	86.4	336.3
Net income	69.2	43.5	19.0	27.6	159.3
Net income attributable to Targa / common shareholders	9.6	8.6	8.7	11.2	38.1
Net income per common share - basic	$0.23	$0.21	$0.21	$0.27	$0.93
Net income per common share - diluted	$0.23	$0.21	$0.21	$0.27	$0.91
2011					
Revenues	$1,618.6	$1,728.3	$1,713.6	$1,934.0	$6,994.5
Gross margin	217.4	250.5	228.1	259.5	955.5
Operating income	73.5	98.5	70.8	108.3	351.1
Net income	40.8	63.3	36.5	74.8	215.4
Net income attributable to Targa / common shareholders	6.8	10.5	4.9	8.5	30.7
Net income per common share - basic	$0.17	$0.26	$0.12	$0.21	$0.75
Net income per common share - diluted	$0.16	$0.25	$0.12	$0.20	$0.74

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Note 25— Condensed Parent Only Financial Statements

The condensed financial statements represent the financial information required by Rule 5-04 of the Securities and Exchange Commission Regulation S-X for Targa Resources Corp.

In the condensed financial statements, Targa's investments in consolidated subsidiaries are presented under the equity method of accounting. Under this method, the assets and liabilities of affiliates are not consolidated. The investments in net assets of the consolidated subsidiaries are recorded in the balance sheets. Intercompany debt holdings related to the Holdco debt extinguishment transactions (See Note 10) have been eliminated. The income (loss) from operations of the consolidated subsidiaries is reported as equity in income (loss) of consolidated subsidiaries.

A substantial amount of Targa's operating, investing and financing activities are conducted by its affiliates. The condensed financial statements should be read in conjunction with Targa's consolidated financial statements, which begin on page F-3 of this Annual Report.

TARGA RESOURCES CORP.
PARENT ONLY
CONDENSED BALANCE SHEET

	December 31, 2012	December 31, 2011
	(In millions)	
ASSETS		
Investment in consolidated subsidiaries	$201.6	$232.3
Deferred income taxes	24.5	16.0
Long-term debt issue costs	1.7	0.4
Total assets	$227.8	$248.7
LIABILITIES AND STOCKHOLDERS' EQUITY		
Accrued current liabilities	$1.5	$-
Long-term debt	82.0	89.3
Other long-term liabilities	0.2	1.3
Commitments and contingencies		
Convertible cumulative participating series B preferred stock	-	-
Targa Resources Corp. stockholders' equity	144.1	158.1
Total liabilities and stockholders' equity	$227.8	$248.7

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TARGA RESOURCES CORP.
PARENT ONLY
CONDENSED STATEMENT OF OPERATIONS

	Year Ended December 31,		
	2012	2011	2010
	(In millions, except per share amounts)		
Equity in net income (loss) of consolidated subsidiaries	$40.8	$38.9	$(16.3)
General and administrative expenses	(8.2)	(8.5)	(20.5)
Gain on sale of assets	-	-	1.1
Income (loss) from operations	32.6	30.4	(35.7)
Other income (expense):			
Gain on debt extinguishment	0.2	-	35.2
Interest expense	(3.2)	(3.1)	(11.2)
Income (loss) before income taxes	29.6	27.3	(11.7)
Deferred income tax (expense) benefit	8.5	3.4	(3.3)
Net income (loss) attributable to Targa Resources Corp.	38.1	30.7	(15.0)
Dividends on Series B preferred stock	-	-	(9.5)
Dividends on common equivalents	-	-	(177.8)
Net income (loss) available to common shareholders	$38.1	$30.7	$(202.3)
Net income (loss) available per common share - basic	$0.93	$0.75	$(30.94)
Net income (loss) available per common share - diluted	$0.91	$0.74	$(30.94)
Weighted average shares outstanding - basic	41.0	41.0	6.5
Weighted average shares outstanding - diluted	41.8	41.4	6.5

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TARGA RESOURCES CORP.
PARENT ONLY
CONDENSED STATEMENT OF CASH FLOWS

	Year Ended December 31,		
	2012	2011	2010
		(In millions)	
Net cash used in operating activities	$0.9	$-	$(4.4)
Investing activities:			
Distribution and return of advances from consolidated subsidiaries	78.5	38.2	721.0
Net cash provided by investing activities	78.5	38.2	721.0
Financing activities:			
Long-term debt borrowings	90.0	-	-
Long-term debt repayments	(96.8)	-	(269.3)
Costs incurred in connection with financing arrangements	(1.0)	-	-
Issuance of common stock	-	-	0.9
Repurchase of common stock	(9.5)	-	(0.1)
Dividends to common and common equivalent shareholders	(62.2)	(38.2)	(210.1)
Dividends to preferred shareholders	-	-	(238.0)
Excess tax benefit from stock-based awards	1.3	-	-
Distribution to owners	(1.2)	-	-
Net cash used in financing activities	(79.4)	(38.2)	(716.6)
Net increase (decrease) in cash and cash equivalents	-	-	-
Cash and cash equivalents - beginning of year	-	-	-
Cash and cash equivalents - end of year	$-	$-	$-