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

TABLE OF CONTENTS

PART I

Item 1. Business.	4
Item 1A. Risk Factors.	34
Item 1B. Unresolved Staff Comments.	56
Item 2. Properties.	56
Item 3. Legal Proceedings.	56
Item 4. Mine Safety Disclosures.	56
PART II	
Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.	57
Item 6. Selected Financial Data.	60
Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.	61
Item 7A. Quantitative and Qualitative Disclosures About Market Risk.	97
Item 8. Financial Statements and Supplementary Data.	100
Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure.	100
Item 9A. Controls and Procedures.	100
Item 9B. Other Information.	100
PART III	
Item 10. Directors, Executive Officers and Corporate Governance.	101
Item 11. Executive Compensation.	107
Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.	132
Item 13. Certain Relationships and Related Transactions, and Director Independence.	134
Item 14. Principal Accounting Fees and Services.	139

PART IV

Item 15. Exhibits, Financial Statement Schedules.	140

Table of Contents

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Targa Resources Corp.'s (together with its subsidiaries, other than Targa Resources Partners LP (the "Partnership"), 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.

Table of Contents

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

Table of Contents

PART I

Item 1. Business.

Overview

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

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.

Table of Contents

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:

- 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.

Table of Contents

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.

Table of Contents

- 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.

Table of Contents

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.

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.

Table of Contents

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."

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

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.

Table of Contents

The Partnership also has a natural gasoline hydrotreater at Mont Belvieu, Texas that removes sulfur from natural gasoline, allowing customers to meet new, more stringent environmental standards. 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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.”

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.

26

Table of Contents

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.

Table of Contents

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

Environmental and Operational Health and Safety Matters

General

The Partnership's operations are subject to stringent and complex federal, 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.

Table of Contents

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

The Partnership currently owns or leases and has in the past owned or leased properties that for many years have been used for midstream natural gas and NGL activities and refined petroleum product and crude oil storage and terminaling activities. Although the Partnership has utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other substances and wastes may have been disposed of or released on or under the properties owned or leased by the Partnership or on or under the other locations where these hydrocarbons or other substances and wastes have been taken for treatment or disposal. In addition, certain of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other substances and wastes was not under 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.

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.

Table of Contents

Hydraulic Fracturing

It is customary to recover natural gas from deep shale formations through the use of hydraulic fracturing, combined with sophisticated horizontal drilling. Hydraulic fracturing involves the injection of water, sand and chemical additives under pressure into rock formations to stimulate gas production. The process is typically regulated by state oil and gas commissions but 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.

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.

Table of Contents

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.

Table of Contents

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

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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;

Table of Contents

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;

- 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;

Table of Contents

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.

Table of Contents

If the Partnership does not make acquisitions or develop growth projects for expanding existing assets or constructing new midstream assets on economically acceptable terms or 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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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:

- 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;

Table of Contents

- 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.

Table of Contents

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.

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.

Table of Contents

The crude oil pipeline system that is part of the Badlands assets has qualified for a temporary waiver of applicable FERC regulatory requirements under the ICA based on current circumstances. Such waivers are subject to revocation, however, 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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

Item 6. Selected Financial Data.

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

Table of Contents

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

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

Overview

Financial Presentation

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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."

Table of Contents

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.

Table of Contents

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.

Table of Contents

Our Non-GAAP Measures

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

	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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

Non-GAAP Financial Measures of the Partnership

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

	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.

Table of Contents

	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.

Table of Contents

Financial Information – Partnership versus Non-Partnership

As a supplement to the financial statements included in this Annual Report, we present the following tables which segregate our consolidated balance 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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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).

Table of Contents

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

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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."

- 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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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	-	-	-

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(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.

Table of Contents

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.

Table of Contents

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.”

Table of Contents

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.

Table of Contents

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					