Targa Resources Corp.
Form S-1
April 01, 2011

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As filed with the Securities and Exchange Commission on April 1, 2011

Registration No. 333-

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

Form S-1

REGISTRATION STATEMENT
UNDER
THE SECURITIES ACT OF 1933

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

Delaware	**4922**	**20-3701075**
(State or other jurisdiction of incorporation or organization)	*(Primary Standard Industrial Classification Code Number)*	*(I.R.S. Employer Identification Number)*

1000 Louisiana, Suite 4300
Houston, Texas 77002
(713) 584-1000
(Address, including zip code, and telephone number, including area code, of registrant s principal executive offices)

Rene R. Joyce
Chief Executive Officer
1000 Louisiana, Suite 4300
Houston, Texas 77002
(713) 584-1000
(Name, address, including zip code, and telephone number, including area code, of agent for service)

Copies to:

David P. Oelman
Christopher S. Collins
Vinson & Elkins LLP
1001 Fannin Street, Suite 2500
Houston, Texas 77002
(713) 758-2222

Douglass M. Rayburn
Baker Botts L.L.P.
2001 Ross Avenue
Dallas, Texas 75201
(214) 953-6500

Approximate date of commencement of proposed sale to the public: As soon as practicable after this Registration Statement becomes effective.

If any of the securities being registered on this Form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act, check the following box. o

If this Form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, please check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If this Form is a post-effective amendment filed pursuant to Rule 462(c) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If this Form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

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. (Check one):

Large accelerated filer o Accelerated filer o Non-accelerated filer þ (Do not check if a smaller reporting company) Smaller reporting company o

CALCULATION OF REGISTRATION FEE

	Amount to be	**Proposed Maximum Offering Price**	**Proposed Maximum Aggregate**	**Amount of**

Title of Each Class of Securities to Be Registered	Registered[(1)]	Per Share[(2)]	Offering Price[(2)]	Registration Fee[(2]
ommon Stock, par value $0.01 per share	6,500,000	$35.63	$231,595,000	$26,888.18

(1) Includes common stock issuable upon exercise of the underwriters option to purchase additional shares of common stock.

(2) Calculated in accordance with Rule 457(c) based on the average of the high and low prices of our common stock as reported by the New York Stock Exchange on March 31, 2011.

The Registrant hereby amends this Registration Statement on such date or dates as may be necessary to delay its effective date until the registrant shall file a further amendment which specifically states that this Registration Statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act of 1933 or until the Registration Statement shall become effective on such date as the Securities and Exchange Commission acting pursuant to said Section 8(a), may determine.

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Subject to Completion, dated April 1, 2011

PROSPECTUS

Shares

Targa Resources Corp.
Common Stock

The selling stockholders identified in this prospectus are offering shares of our common stock. We will not receive any proceeds from the sale of shares by the selling stockholders.

An affiliate of Merrill Lynch, Pierce, Fenner & Smith Incorporated, an underwriter in this offering, is a selling stockholder. See Underwriting (Conflicts of Interest) Conflicts of Interest.

Our common stock trades on the New York Stock Exchange under the symbol TRGP. The last reported trading price of our common stock on the New York Stock Exchange on March 31, 2011 was $36.24 per share of common stock.

Investing in our common stock involves risks. See Risk Factors beginning on page 20 of this prospectus.

	Per Share	**Total**
Price to the public	$	$
Underwriting discounts and commissions	$	$
Proceeds to the selling stockholders	$	$

Certain of the selling stockholders have granted the underwriters a 30-day option to purchase up to an additional shares of common stock on the same terms and conditions as set forth above if the underwriters sell more than shares of common stock in this offering.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or passed on the adequacy or accuracy of this prospectus. Any representation to the contrary is a criminal offense.

Barclays Capital, on behalf of the underwriters, expects to deliver the shares on or about , 2011.

Barclays Capital **BofA Merrill Lynch**

Prospectus dated , 2011

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You should rely only on the information contained in this prospectus. We have not, and the underwriters have not, authorized anyone to provide you with different information. If anyone provides you with different or inconsistent information, you should not rely on it. We are not, and the underwriters are not, making an offer to sell these securities in any jurisdiction where an offer or sale is not permitted. You should assume that the information appearing in this prospectus is accurate as of the date on the front cover of this prospectus. Our business, financial condition, results of operations and prospects may have changed since that date.

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SUMMARY

This summary provides a brief overview of information contained elsewhere in this prospectus. Because it is abbreviated, this summary may not contain all of the information that you should consider before investing in our common stock. You should read the entire prospectus carefully, including the historical financial statements and the notes to those financial statements. Unless indicated otherwise, the information presented in this prospectus assumes that the underwriters do not exercise their option to purchase additional shares of our common stock. You should read Risk Factors beginning on page 20 for more information about important risks that you should consider carefully before investing in our common stock. We include a glossary of some of the terms used in this prospectus as Appendix A.

As used in this prospectus, unless we indicate otherwise: (1) our, we, us, TRC, Targa, and the Company, and terms refer either to Targa Resources Corp., in its individual capacity, or to Targa Resources Corp. and its subsidiaries collectively, as the context requires, (2) the General Partner refers to Targa Resources GP LLC, the general partner of the Partnership, (3) the Partnership refers to Targa Resources Partners LP, in its individual capacity, to Targa Resources Partners LP and its subsidiaries collectively, or to Targa Resources Partners LP together with combined entities for predecessor periods under common control, as the context requires and (4) TRI refers to TRI Resources Inc., an indirect wholly-owned subsidiary of us.

Targa Resources Corp.

We own general and limited partner interests, including incentive distribution rights (IDRs), in Targa Resources Partners LP (NYSE: NGLS), a publicly traded Delaware limited partnership 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, storing, fractionating, treating, transporting and selling natural gas liquids, or NGLs, and NGL products and storing and terminaling refined petroleum products and crude oil.

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. We also may enter into other economic transactions intended to increase our ability to make cash available for dividends over time. In addition, we may acquire assets that could be candidates for acquisition by the Partnership, potentially after operational or commercial improvement or further development.

As of March 31, 2011, 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
- 11,645,659 of the 84,756,009 outstanding common units of the Partnership, representing 13.7% of the limited partnership interest in the Partnership.

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 respect for that quarter;

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Our ownership in respect to the IDRs of the Partnership that we hold 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.

On February 14, 2011, the Partnership paid a quarterly cash distribution of $0.5475 per common unit, or $2.19 per common unit on an annualized basis, for the fourth quarter of 2010. Such distribution resulted in a quarterly distribution to us of $7.1 million, or $28.2 million on an annualized basis, in respect of our 2% general partner interest and IDRs, and $6.4 million, or $25.5 million on an annualized basis, in respect of our common units in the Partnership, for total quarterly distributions of $13.5 million, or $53.7 million on an annualized basis.

On February 21, 2011, we paid a cash dividend of $0.0616 per share of common stock, or $2.6 million in total, to holders of our outstanding common stock. The dividend was prorated to give effect to a partial quarter following our initial public offering, or IPO, and corresponds to a full dividend of $0.2575 per share on a quarterly basis, or $1.03 per share on an annualized basis.

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. See Our Dividend Policy.

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The following graph shows the historical cash distributions declared by the Partnership for the periods shown to its limited partners (including us), to us based on our 2% general partner interest in the Partnership and to us based on the IDRs. The increases in historical cash distributions to both the limited partners and the general partner since the second quarter ended June 30, 2007, as reflected in the graph set forth below, generally resulted from increases in the Partnership s per unit quarterly distribution over time and the issuance of approximately 53.9 million additional common units by the Partnership over time to finance acquisitions and capital improvements. Over the same period, the quarterly distributions declared by the Partnership in respect of our 2% general partner interest and IDRs increased approximately 3,200% from $0.2 million to $7.1 million.

Quarterly Cash Distributions by the Partnership

The graph set forth below shows hypothetical cash distributions payable to us in respect of our interests in the Partnership across an illustrative range of annualized distributions per common unit. This information is based upon the following:

(i) the Partnership has a total of 84,756,009 common units outstanding; and

(ii) we own (i) a 2% general partner interest in the Partnership, (ii) the IDRs and (iii) 11,645,659 common units of the Partnership.

The graph below also illustrates the impact on us of the Partnership raising or lowering its per common unit distribution from the 2010 fourth quarter quarterly distribution of $0.5475 per common unit, or $2.19 per common unit on an annualized basis. This information is presented for illustrative purposes only; it is not intended to be a prediction of future performance and does not attempt to illustrate the impact that changes in our or the Partnership s business, including changes that may result from changes in interest rates, energy prices or general economic conditions, or the impact that any future acquisitions or

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expansion projects, divestitures or issuances of additional debt or equity securities will have on our or the Partnership s results of operations.

Hypothetical Annualized Pre-Tax Partnership Distributions to Us

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.

Targa Resources Partners LP

The Partnership is a leading provider of midstream natural gas and NGL services in the United States and is engaged in the business of gathering, compressing, treating, processing and selling natural gas, storing, fractionating, treating, transporting and selling NGLs and NGL products and storing and terminaling refined petroleum products and crude oil. The Partnership operates in two primary divisions: (i) Natural Gas 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.

The Partnership currently owns interests in or operates approximately 11,372 miles of natural gas pipelines and approximately 800 miles of NGL pipelines, with natural gas gathering systems covering approximately 13,500 square miles and 22 natural gas processing plants with access to natural gas supplies in the Permian Basin, the Fort Worth Basin, the onshore region of the Louisiana Gulf Coast and the Gulf of Mexico.

Additionally, the Partnership s integrated Logistics and Marketing division, or Downstream Business, has net fractionation and treating capacity of approximately 385 MBbl/d, 39 owned and operated storage wells that are in service with a net storage capacity of approximately 65 MMBbl, and 16 storage, marine and transport terminals with above ground storage capacity of approximately 1.4 MMBbl.

Since the beginning of 2007, the Partnership has completed six acquisitions from us with an aggregate purchase price of approximately $3.1 billion. In addition, 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, some of which occurred before the Partnership acquired its various businesses from us, have involved growth capital expenditures of approximately $313 million since 2005. We believe that the Partnership is well positioned to continue the successful execution of its business strategies, including accretive acquisitions and expansion projects, and that the Partnership s inventory of growth projects should help to sustain continued growth in cash distributions paid by the Partnership.

Based on the Partnership s closing common unit price on March 31, 2011, the Partnership has an equity market capitalization of $2.9 billion. As of December 31, 2010, the Partnership had total assets of $3.2 billion.

Recent Transactions

In March 2011, the Partnership acquired a refined petroleum products and crude oil storage and terminaling facility in Channelview, TX. Located on Carpenter s Bayou along the Houston Ship Channel, the terminal can handle multiple grades of blend stocks, products and crude. The Partnership expects that the transaction will be immediately accretive to its unitholders and is complementary to its existing terminal asset base and business along the Gulf Coast. The Partnership expects to invest incremental growth capital in the near future to expand the capacity of the terminal.

On January 24, 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 $259.3 million. Pursuant to the exercise of the underwriters overallotment option, on February 3, 2011 the Partnership sold an additional 1,200,000 common units, providing net proceeds of $38.9 million. In addition, we contributed $6.3 million for 187,755 general partner units to maintain our 2% general partner interest in the Partnership. The Partnership used the net proceeds from the offering to reduce borrowings under its senior secured credit facility.

Partnership Growth Drivers

We believe the Partnership s near-term growth will be driven both by significant recently completed or pending projects as well as strong supply and demand fundamentals for its existing businesses. Over the longer-term, we expect the Partnership s growth will be driven by natural gas shale opportunities, which could lead to growth in both the Partnership s Gathering and Processing division and Downstream Business, organic growth projects and potential strategic and other acquisitions related to its existing businesses.

Organic growth projects. We expect the Partnership s near-term growth to be driven by a number of significant projects scheduled for completion in 2011or early 2012 that are supported by long-term, fee-based contracts. These projects include:

> *Cedar Bayou Fractionator expansion project:* The Partnership is currently starting up the approximately 78 MBbl/d of additional fractionation capacity at the Partnership s 88% owned Cedar Bayou Fractionator (CBF) in Mont Belvieu. The capital cost is expected to be less than the original estimated gross cost of $78 million.
>
> *Benzene treating project:* A new treater is under construction which will operate 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 treater has an estimated gross cost of approximately $33 million and is expected to be completed and operating by the end of the year.

Gulf Coast Fractionators expansion project: The Partnership has announced plans by Gulf Coast Fractionators (GCF), a partnership with ConocoPhillips and Devon Energy Corporation in which the Partnership owns a 38.8% interest, to expand the capacity of its NGL fractionation facility in Mont Belvieu by 43 MBbl/d for an estimated gross cost of $75 million.

SAOU Expansion Program: The Partnership has announced a $30 million capital expenditure program including new compression facilities and pipelines as well as expenditures to restart the 25 MMcf/d Conger processing plant in response to strong volume growth and new well connects. The Partnership expects the Conger plant to restart in April 2011. Additionally, two 15 MMcf/d processing trains from the Garden City plant are being refurbished for future use at another SAOU location.

North Texas Expansion Program: The board of directors of the General Partner has approved approximately $40 million of capital expenditures to expand the gathering and processing capability of the Partnership s North Texas System with certain provisions of the approved expenditures subject to finalization of ongoing customer commercial agreements. The expansion program is a response to strong volume growth and new well connects associated with producer activity in oilier portions of the Barnett Shale natural gas play. Management expects that additional investment will be required to keep pace with producer activity.

Additionally, the Partnership is actively pursuing other gathering and processing expansion opportunities, especially for the North Texas System, SAOU and the Sand Hills facilities. In the Downstream Business, the Partnership submitted a standard air permit application for a second CBF expansion of approximately 100 MBbl/d. Having recently passed the 45 day waiting period without regulator objection, the Partnership expects the permit registration to be received in April. With the passage of the waiting period, the Partnership has regulatory authority to proceed with the project, which it expects to do pending execution of precedent anchor commercial commitments. Furthermore, international interest in additional propane and/or butane exports has increased utilization of the Partnership s existing export facilities and offers prospects for a longer term potential expansion of the Partnership s Galena Park export facilities backed by precedent contracts. Finally, the Partnership s recently added petroleum products and crude storage and terminaling team closed its first acquisition in March, is pursuing organic expansion for that acquisition and is actively pursuing other refined products and crude storage and terminaling acquisition opportunities.

Strong supply and demand fundamentals for the Partnership s existing businesses. We believe that the current strength of oil, condensate and NGL prices and of forecast prices for these energy commodities has caused producers in and around the Partnership s 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 the Wolfberry Trend and Canyon Sands plays, which are accessible by the SAOU processing business in the Permian Basin (known as SAOU), 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.

Producer activity in areas rich in oil, condensate and NGLs is 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. Until additional fractionation capacity comes on-line in 2011, there will be limited incremental supply of fractionation services in the area. These strong supply and demand fundamentals have resulted in long-term, frac-or-pay contracts for existing capacity and support the construction of new fractionation capacity, such as the Partnership s CBF and GCF expansion projects. The Partnership is 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 Partnership s Downstream Business.

Active drilling and production activity from liquids- rich shale gas 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 shale gas plays such as portions of the Barnett Shale

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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/other geologic cross-section combinations) and the Bone Springs/Avalon Shale plays. We believe that the Partnership s leadership position in the Downstream Business, which includes fractionation services, provides the Partnership with a competitive advantage relative to other gathering and processing companies without these capabilities.

Potential third party acquisitions related to the Partnership s existing businesses. While the Partnership s recent growth has been partially driven by the implementation of a focused drop drown strategy, our management team also has a record of successful third party acquisitions. Since our formation, our strategy has included approximately $3 billion in acquisitions and growth capital expenditures. We expect that third-party acquisitions will continue to be a significant focus of the Partnership s growth strategy.

The Partnership s Competitive Strengths and Strategies

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

The Partnership is one of the largest and best positioned/interconnected fractionators of NGLs in the Gulf Coast.

The Partnership s gathering and processing businesses are predominantly located in active and growth oriented oil and gas producing basins.

The Partnership provides a comprehensive package of services to natural gas producers.

The Partnership maintains gathering and processing positions in strategic oil and gas producing areas across multiple basins and provides services under attractive contract terms to a diverse mix of customers.

The Partnership s gathering and processing systems and logistics assets consist of high-quality, well maintained facilities, resulting in low cost, efficient operations.

Maintaining appropriate leverage and distribution coverage levels and mitigating commodity price volatility allow the Partnership to be flexible in its growth strategy and enable it to pursue strategic acquisitions and large growth projects.

The executive management team which formed TRI in 2004 and continues to manage Targa today possesses over 200 years of combined experience working in the midstream natural gas and energy business.

The Partnership s Challenges

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

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

The Partnership s cash flow is affected by supply and demand for oil, natural gas and NGL products and by natural gas and NGL 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 and NGLs, which depends on certain factors beyond its control. Any decrease in supplies of natural gas or NGLs could adversely affect the Partnership s business and operating results.

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

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- The Partnership is subject to regulatory, environmental, political, legal, credit 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 its 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 the Partnership s business and operating results.

For a further discussion of these and other challenges we and the Partnership face, please read Risk Factors.

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(1) Please see Security Ownership of Management and Selling Stockholders for information regarding the beneficial ownership of our common stock for our executive officers and directors.

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The Offering

Common stock offered by the selling stockholders	shares (shares if the underwriters over-allotment is exercised in full)
Common stock outstanding as of March 31, 2011	42,349,738 shares
Over-allotment option	Certain of the selling stockholders have granted the underwriters a 30-day option to purchase up to an aggregate of additional shares of our common stock to cover over-allotments.
Use of proceeds	We will not receive any proceeds from the sale of shares by the selling stockholders. See Use of Proceeds.
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; reserves our board of directors believes prudent to maintain; and capital contributions to the Partnership upon the issuance by it of additional partnership securities if we choose to maintain the General Partner s 2% interest.
Dividends	We paid a prorated dividend of $0.0616 per share of common stock for the portion of the fourth quarter of 2010 that we were public on February 21, 2011 to stockholders of record on February 3, 2011. The prorated dividend corresponds to a full dividend of $0.2575 per share on a quarterly basis, or $1.03 per share on an annualized basis. We cannot assure you that any dividends will be declared or paid by us. Please read Our Dividend Policy.
Tax	For a discussion of the material tax consequences that may be relevant to prospective stockholders who are non-U.S. holders (as defined below), please read Material U.S. Federal Income Tax Consequences to Non-U.S. Holders.
Risk factors	You should carefully read and consider the information beginning on page 20 of this prospectus set forth under the heading Risk Factors and all other information set forth in this prospectus before deciding to invest in

our common stock.

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New York Stock Exchange symbol	TRGP
Conflicts of interest	An affiliate of Merrill Lynch, Pierce, Fenner & Smith Incorporated, an underwriter in this offering, currently owns equity interests representing a 2.9% ownership interest in us and is selling shares of common stock in connection with this offering and will own shares of our common stock, representing a % ownership interest in us on a fully diluted basis upon completion of this offering. Because of this relationship, this offering is being conducted in accordance with FINRA Rule 5121. This rule requires, among other things, that a qualified independent underwriter has participated in the preparation of, and has exercised the usual standards of due diligence with respect to, this prospectus and the registration statement of which this prospectus is a part. Barclays Capital Inc. is acting as the qualified independent underwriter. See Underwriting (Conflicts of Interest) Conflicts of Interest.

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Comparison of Rights of Our Common Stock and the Partnership s Common Units

Our shares of common stock and the Partnership s common units are unlikely to trade, either by volume or price, in correlation or proportion to one another. Instead, while the trading prices of our shares and the common units may follow generally similar broad trends, the trading prices may diverge because, among other things:

- common unitholders of the Partnership have a priority over the IDRs with respect to the Partnership distributions;
- we participate in the General Partner s distributions and IDRs and the common unitholders do not;
- we and our stockholders are taxed differently from the Partnership and its common unitholders; and
- we may enter into other businesses separate and apart from the Partnership or any of its affiliates.

An investment in common units of a partnership is inherently different from an investment in common stock of a corporation.

	Partnership s Common Units	Our Shares
Distributions and Dividends	The Partnership pays its limited partners and the General Partner quarterly distributions equal to all of the available cash from operating surplus. The General Partner has a 2% general partner interest. Common unitholders do not participate in the distributions to the General Partner or in the IDRs.	We intend to pay our stockholders, on a quarterly basis, dividends equal to the cash the Partnership distributes to us based on our ownership of Partnership interests, less 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, capital contributions to the Partnership upon the issuance by it of additional Partnership securities if we choose to maintain the General Partner s 2% interest and reserves established by our board of directors. We receive distributions from the Partnership with respect to our 11,645,659 common units.

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	Partnership s Common Units	Our Shares
		In addition, through our ownership of the Partnership s general partner, we participate in the distributions to the General Partner pursuant to the 2% general partner interest and the IDRs. If the Partnership is successful in implementing its strategy to increase distributable cash flow, our income from these rights may increase in the future. However, no distributions may be made on the IDRs until the minimum quarterly distribution has been paid on all outstanding common units. Therefore, distributions with respect to the IDRs are even more uncertain than distributions on the common units.
Taxation of Entity and Equity Owners	The Partnership is a flow-through entity that is not subject to an entity level federal income tax. The Partnership expects that holders of units in the Partnership other than us will benefit for a period of time from tax basis adjustments and remedial allocations of deductions so that they will be allocated a relatively small amount of federal taxable income compared to the cash distributed to them.	Our taxable income is subject to U.S. federal income tax at the corporate tax rate, which is currently a maximum of 35%. In addition, we will be allocated more taxable income relative to our Partnership distributions than the other common unitholders and the relative amount thereof may increase if the Partnership issues additional units or distributes a higher percentage of cash to the holder of the IDRs.

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	Partnership s Common Units	Our Shares
	Common unitholders will receive Forms K-1 from the Partnership reflecting the unitholders share of the Partnership s items of income, gain, loss, and deduction. Tax-exempt organizations, including employee benefit plans, will have unrelated business taxable income as a result of the allocation of the Partnership s items of income, gain, loss, and deduction to them. Regulated investment companies or mutual funds will be allocated items of income, which may not constitute qualifying income, as a result of the ownership of common units.	Because we are not a flow-through entity, our stockholders do not report our items of income, gain, loss and deduction on their federal income tax returns. Distributions to our stockholders will constitute dividends for U.S. tax purposes to the extent of our current or accumulated earnings and profits. To the extent those distributions are not treated as dividends, they will be treated as gain from the sale of the common stock to the extent the distribution exceeds a stockholder s adjusted basis in the common stock sold. Our stockholders will generally recognize capital gain or loss on the sale of our common stock equal to the difference between a stockholder s adjusted tax basis in the shares of common stock sold and the proceeds received by such holder. This gain or loss will generally be long-term gain or loss if a holder sells shares of common stock held for more than one year. Under current law, long-term capital gains of individuals generally are subject to a reduced rate of U.S. federal income tax. Tax-exempt organizations, including employee benefit plans, will not have unrelated business taxable income upon the receipt of dividends from us. Regulated investment companies or mutual funds will have qualifying income as a result of dividends received from us.

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	Partnership s Common Units	Our Shares
Voting	Certain significant decisions require approval by a unit majority of the common units. These significant decisions include, among other things: merger of the Partnership or the sale of all or substantially all of its assets in certain circumstances; and certain amendments to the Partnership s partnership agreement. For more information, please read Material Provisions of the Partnership s Partnership Agreement Voting Rights.	Under our amended and restated bylaws, each stockholder is entitled to cast one vote, either in person or by proxy, for each share standing in his or her name on the books of the corporation as of the record date. Our amended and restated certificate of incorporation and amended and restated bylaws contain supermajority voting requirements for certain matters. See 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 Certificate of Incorporation and Bylaws.
Election, Appointment and Removal of General Partner and Directors	Common unitholders do not elect the directors of Targa Resources GP LLC. Instead, these directors are elected annually by us, as the sole equity owner of Targa Resources GP LLC. The Partnership s general partner may not be removed unless that removal is approved by the vote of the holders of not less than 662/3% of the outstanding units, voting together as a single class, including units held by the general partner and its affiliates, and the Partnership receives an opinion of counsel regarding limited liability and tax matters.	We have a staggered board of three classes with each class being elected every three years and only one class elected each year. Also, each director shall hold office until the director s successor shall have been duly elected and shall qualify or until the director shall resign or shall have been removed. Directors serving on our board may only be removed from office for cause and only by the affirmative vote of a supermajority of our stockholders. See 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 Certificate of Incorporation and Bylaws.
Preemptive Rights to Acquire Securities	Common unitholders do not have preemptive rights. Whenever the Partnership issues equity securities to any person other than the General Partner and its	Our stockholders do not have preemptive rights.

affiliates, the General Partner has a preemptive right to purchase additional limited partnership interests on the same terms in order to maintain its percentage interest.

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	Partnership s Common Units	Our Shares
Liquidation	The Partnership will dissolve upon any of the following the election of the general partner to dissolve the Partnership, if approved by the holders of units representing a unit majority; there being no limited partners, unless the Partnership is continued without dissolution in accordance with applicable Delaware law; the entry of a decree of judicial dissolution of the Partnership pursuant to applicable Delaware law; or the withdrawal or removal of the General Partner or any other event that results in its ceasing to be the general partner other than by reason of a transfer of its general partner interest in accordance with the Partnership s partnership agreement or withdrawal or removal following approval and admission of a successor.	We will dissolve upon any of the upon any of the following: the entry of a decree of judicial dissolution of us; or the approval of at least 67% of our outstanding common stock.

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Principal Executive Offices and Internet Address

Our principal executive offices are located at 1000 Louisiana, Suite 4300, Houston, Texas 77002 and our telephone number is (713) 584-1000. Our website is located at *www.targaresources.com.* We make our periodic reports and other information filed with or furnished to the Securities and Exchange Commission, or the SEC, available, free of charge, through our website, as soon as reasonably practicable after those reports and other information are electronically filed with or furnished to the SEC. Information on our website or any other website is not incorporated by reference into this prospectus and does not constitute a part of this prospectus.

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Summary Consolidated Financial and Operating Data

Because we control Targa Resources GP LLC, our consolidated financial information incorporates the consolidated financial information of Targa Resources Partners LP.

The following table presents summary historical consolidated financial and operating data of Targa Resources Corp. for the periods and as of the dates indicated. The summary historical consolidated statement of operations and cash flow data for the years ended December 31, 2008, 2009 and 2010 and summary historical consolidated balance sheet data as of December 31, 2009 and 2010 have been derived from our audited financial statements, and that information should be read together with and is qualified in its entirety by reference to, the historical consolidated financial statements and accompanying notes included elsewhere in this prospectus. The summary historical consolidated balance sheet data as of December 31, 2008 has been derived from audited financial statements that are not included in this prospectus.

	For the Years Ended December 31,		
	2008	**2009**	**2010**
	(In millions, except operating, per common share and price data)		
Revenues[(1)]	$ 7,998.9	$ 4,536.0	$ 5,469.2
Product purchases	7,218.5	3,791.1	4,687.7
Gross margin[(2)]	780.4	744.9	781.5
Operating expenses	275.2	235.0	260.2
Operating margin[(3)]	505.2	509.9	521.3
Depreciation and amortization expenses	160.9	170.3	185.5
General and administrative expenses	96.4	120.4	144.4
Other	13.4	2.0	(4.7)
Income from operations	234.5	217.2	196.1
Interest expense, net	(141.2)	(132.1)	(110.9)
Gain on insurance claims	18.5		
Equity in earnings of unconsolidated investments	14.0	5.0	5.4
Gain (loss) on debt repurchases	25.6	(1.5)	(17.4)
Gain on early debt extinguishment	3.6	9.7	12.5
Gain (loss) on mark-to-market derivative instruments	(1.3)	0.3	(0.4)
Other		1.2	0.5
Income tax expense:	(19.3)	(20.7)	(22.5)
Net income	134.4	79.1	63.3
Less: Net income attributable to non controlling interest	97.1	49.8	78.3
Net income (loss) attributable to Targa Resources Corp.	37.3	29.3	(15.0)
Dividends on Series B preferred stock	(16.8)	(17.8)	(9.5)
Less:			
Undistributed earnings attributable to preferred shareholders	(20.5)	(11.5)	
Dividends to common equivalents			(177.8)

Net income (loss) available to common shareholders	$	$	$ (202.3)
Net income (loss) available per common share basic and diluted	$	$	$ (30.94)
Operating data:			
Plant natural gas inlet, MMcf/d(4),(5)	1,846.4	2,139.8	2,268.0
Gross NGL production, MBbl/d	101.9	118.3	121.2
Natural gas sales, BBtu/d(5)	532.1	598.4	685.1
NGL sales, MBbl/d	286.9	279.7	251.5
Condensate sales, MBbl/d	3.8	4.7	3.5
Average realized prices(6):			
Natural gas, $/MMBtu	$ 8.20	$ 3.96	$ 4.43
NGL, $/gal	1.38	0.79	1.06
Condensate, $/Bbl	91.28	56.32	73.68

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	For the Years Ended December 31,		
	2008	2009	2010
	(In millions, except operating, per common share and price data)		
Balance Sheet Data (at period end):			
Property plant and equipment, net	$ 2,617.4	$ 2,548.1	$ 2,509.0
Total assets	3,641.8	3,367.5	3,393.8
Long-term debt, less current maturities	1,976.5	1,593.5	1,534.7
Convertible cumulative participating Series B preferred stock	290.6	308.4	
Total owners equity	822.0	754.9	1,036.1
Cash Flow Data:			
Net cash provided by (used in):			
Operating activities	$ 390.7	$ 335.8	$ 208.5
Investing activities	(206.7)	(59.3)	(134.6)
Financing activities	0.9	(386.9)	(137.9)

(1) Includes business interruption insurance revenues of $32.9 million, $21.5 million and $6.0 million for the years ended December 31, 2008, 2009 and 2010.

(2) Gross margin is a non-GAAP financial measure and is discussed under Management s Discussion and Analysis of Financial Condition and Results of Operations How We Evaluate Our Operations and How We Evaluate the Partnership s Operations.

(3) Operating margin is a non-GAAP financial measure and is discussed under Management s Discussion and Analysis of Financial Condition and Results of Operations How We Evaluate Our Operations and How We Evaluate the Partnership s Operations.

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

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

(6) Average realized prices include the impact of hedging activities.

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RISK FACTORS

The nature of our business activities subjects us to certain hazards and risks. You should carefully consider the risks described below, in addition to the other information contained in this prospectus, before making an investment decision. Realization of any of these risks or events could have a material adverse effect on our business, financial condition, cash flows and results of operations, which could result in a decline in the trading price of our common stock, and you may lose all or part of your investment.

Risks Inherent in an Investment in Us

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 (i) satisfy tax obligations associated with previous sales of assets to the Partnership, (ii) reimburse the Partnership for certain capital expenditures related to Versado Gas Processors, L.L.C. (Versado) and (iii) provide the Partnership with limited quarterly distribution support through 2011, all as described in more detail in Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources;
- interest expense and principal payments on any indebtedness we incur;
- restrictions on distributions contained in any existing or future debt agreements;
- our general and administrative expenses, including expenses we incur as a result of being a public company as well as other operating expenses;
- expenses of the General Partner;
- income taxes;

- reserves we establish in order for us to maintain our 2% general partner interest in the Partnership upon the issuance of additional partnership securities by the Partnership; and

- reserves our board of directors establishes for the proper conduct of our business, to comply with applicable law or any agreement binding on us or our subsidiaries or to provide for future dividends by us.

The actual amount of cash that is available for dividends to our stockholders will depend on numerous factors, many of which are beyond our control. For additional information, please read Our Dividend Policy.

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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 662/3% 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. Please read Material Provisions of the Partnership s Partnership Agreement Withdrawal or Removal of the General Partner.

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

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

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

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

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

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

Because our only source of operating cash flow consists of cash distributions from the Partnership, the amount of dividends we are able to pay to our stockholders may fluctuate based on the level of distributions the Partnership makes to its partners, including us. The Partnership may not continue to make quarterly distributions at the 2010 fourth quarter distribution level of $0.5475 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 of being a public company 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 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.

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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.

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 holders of common stock. 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 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 we can distribute to you. In addition, to the extent the Partnership issues additional units in connection with any acquisitions or growth capital expenditures, the payment of distributions on those additional 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.

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Restrictions in the Partnership s senior secured credit facility and indentures could limit its ability to make distributions to us.

The Partnership s senior secured credit facility and indentures contain covenants limiting its ability to incur indebtedness, grant liens, engage in transactions with affiliates and make distributions. The Partnership s senior secured credit facility 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 its senior secured credit facility or the indentures.

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.

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

The historical financial information included in this prospectus 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 prospectus 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 the Partnership s business strategy 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 strategy.

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 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 service our and our subsidiaries debt obligations.

Our shares of common stock and the Partnership s common units may not trade in relation or proportion to one another.

The shares of our common stock and the Partnership s common units may not trade, either by volume or price, in correlation or proportion to one another. Instead, while the trading prices of our common stock and the Partnership s common units may follow generally similar broad trends, the trading prices may diverge because, among other things:

- the Partnership s cash distributions to its common unitholders have a priority over distributions on its IDRs;
- we participate in the distributions on the General Partner s general partner interest and IDRs in the Partnership while the Partnership s common unitholders do not;
- we and our stockholders are taxed differently from the Partnership and its common unitholders; and
- we may enter into other businesses separate and apart from the Partnership or any of its affiliates.

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.

The requirements of being a public company, including compliance with the reporting requirements of the Exchange Act and the requirements of the Sarbanes-Oxley Act, may strain our resources, increase our costs and distract management; and we may be unable to comply with these requirements in a timely or cost-effective manner.

As a public company with listed equity securities, we must comply with new laws, regulations and requirements, certain corporate governance provisions of the Sarbanes-Oxley Act of 2002, related regulations of the SEC and the requirements of the New York Stock Exchange, or NYSE, with which we were not required to comply as a private company. Complying with these statutes, regulations and requirements occupies a significant amount of time of our board of directors and management and has significantly increased our costs and expenses. These laws and regulations require us to:

maintain a comprehensive compliance function;

evaluate and maintain an additional system of internal controls over financial reporting in compliance with the requirements of Section 404 of the Sarbanes-Oxley Act of 2002 and the related rules and regulations of the SEC and the Public Company Accounting Oversight Board;

comply with rules promulgated by the NYSE;

prepare and distribute periodic public reports in compliance with our obligations under the federal securities laws;

evaluate and maintain internal policies, such as those relating to disclosure controls and procedures and insider trading;

involve and retain to a greater degree outside counsel and accountants in the above activities; and

augment our investor relations function.

In addition, being a public company requires us to either accept less director and officer liability insurance coverage than we desire or to incur additional costs to maintain coverage. These factors could make it more difficult for us to attract and retain qualified members of our board of directors, particularly to serve on our Audit Committee, and qualified executive officers.

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. After the completion of this offering, we will have 42,349,738 outstanding shares of common stock, of which will be owned by our directors and executive officers and affiliates of Warburg Pincus LLC (Warburg Pincus). A substantial portion of these shares may be sold into the market in the future. Certain of our existing stockholders, including our executive officers, certain of our directors and affiliates of Warburg Pincus, are party to a registration rights agreement with us which requires us to effect the registration of their shares in certain circumstances.

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

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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. We have opted out of this provision of Delaware law until such time as Warburg Pincus and certain transferees do not beneficially own at least 15% of our common stock. 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.

Merrill Lynch, Pierce, Fenner & Smith Incorporated may have a conflict of interest with respect to this offering.

Merrill Lynch Ventures L.P. 2001 (ML Ventures), an affiliate of Merrill Lynch, Pierce, Fenner & Smith Incorporated (BofA Merrill Lynch), an underwriter in this offering, currently owns equity interests representing a 2.9% ownership interest in us and is selling shares of common stock in connection with this offering and will own shares of our common stock, representing a % ownership interest in us on a fully diluted basis upon completion of this offering. Accordingly, BofA Merrill Lynch s interest may go beyond receiving customary underwriting discounts and commissions. In particular, there may be a conflict of interest between BofA Merrill Lynch s own interests as underwriter and the interests of its affiliate, ML Ventures, as a selling stockholder. Because of this relationship, this offering is being conducted in accordance with FINRA Rule 5121. This rule requires, among other things, that a qualified independent underwriter has participated in the preparation of, and has exercised the usual standards of due diligence with respect to, this prospectus and the registration statement of which this prospectus is a part. Accordingly, Barclays Capital Inc. (Barclays Capital) is assuming the responsibilities of acting as the qualified independent underwriter in this offering. Although the qualified independent underwriter has participated in the preparation of the registration statement and prospectus and conducted due diligence, we cannot assure you that this will adequately address any potential conflicts of interest related to BofA Merrill Lynch and ML Ventures. We have agreed to indemnify Barclays Capital for acting as qualified independent underwriter against certain liabilities, including liabilities under the Securities Act of 1933 (the Securities Act) and to contribute to payments that Barclays Capital may be required to make for these liabilities.

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

Upon completion of this offering, affiliates of Warburg Pincus will beneficially own approximately % of our outstanding common stock. See Security Ownership of Management and Selling Stockholders. Accordingly, Warburg Pincus exerts influence over us and any action requiring the approval of the holders of our stock, including the election of directors and approval of significant corporate transactions. Warburg s concentrated ownership makes it less likely that any other holder or group of holders of common stock will be able to affect the way we are managed or the direction of our business. These factors also may delay or prevent a change in our management or voting control.

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

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

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

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 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. For a description of how these conflicts will be resolved, please read Certain Relationships and Related Transactions Conflicts of Interest. 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.

The U.S. federal income tax rate on dividend income is scheduled to increase in 2013.

Our distributions to our stockholders will constitute dividends for U.S. federal income tax purposes to the extent such distributions are paid from our current or accumulated earnings and profits, as determined under U.S. federal income tax principles. Dividends received by certain non-corporate U.S. stockholders, including individuals, are subject to a reduced maximum federal tax rate of 15% for taxable years beginning on or before December 31, 2012. However, for taxable years beginning after December 31, 2012, dividends received by such non-corporate U.S. stockholders will be taxed at the rate applicable to ordinary income of individuals, which is scheduled to increase to a maximum of 39.6%.

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, 2010, the Partnership had approximately $765.3 million of borrowings outstanding under its senior secured credit facility, approximately $101.3 million of letters of credit outstanding and approximately $233.4 million of additional borrowing capacity under its senior secured credit facility. The Partnership s $1.1 billion senior secured revolving credit facility allows it to request increases in commitments up to an additional

$300 million. For the years ended December 31, 2008, 2009 and 2010, the Partnership s consolidated interest expense was $156.1 million, $159.8 million and $110.8 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 the Partnership s lease and other financial obligations and contractual commitments, could have other important consequences to us, including the following:

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

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

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

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

The Partnership s ability to service its debt will depend upon, among other things, its future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond its control. If the Partnership s operating results are not sufficient to service its current or future indebtedness, it will be forced to take actions such as reducing or delaying business activities, acquisitions, investments or capital expenditures, selling assets, restructuring or refinancing debt, or seeking additional equity capital and may adversely affect the Partnership s ability to make cash distributions. The Partnership may not be able to effect 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, 2010, its total indebtedness was $1,445.4 million, of which $680.1 million was at fixed interest rates and $765.3 million was at variable interest rates. After giving effect to interest rate swaps with a notional amount of $300 million, 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 $4.7 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 its substantial leverage.

The Partnership may be able to incur substantial additional indebtedness in the future. As of December 31, 2010, the Partnership had approximately $765.3 million of borrowings outstanding under its senior secured credit facility, approximately, $101.3 million of letters of credit outstanding and approximately $233.4 million of additional borrowing capacity under its senior secured credit facility. The Partnership may be able to incur an additional

$300 million of debt under its senior secured credit facility if it requests and is able to obtain commitments for the additional $300 million available under its senior secured credit facility. Although the Partnership s senior secured credit facility 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

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substantial. If the Partnership incurs additional debt, the risks associated with its substantial leverage would increase.

The terms of the Partnership s senior secured credit facility 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 Partnership s senior secured credit facility and the indentures governing the Partnership s senior notes (other than its 111/4% senior notes due 2017) 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 senior secured credit facility;
- 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 Partnership s senior secured credit facility 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 Partnership s senior secured credit facility 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 its senior secured credit facility, the lenders under senior secured credit facility could proceed against the collateral granted to them to secure that indebtedness. The Partnership has pledged substantially all of its assets as collateral under its senior secured credit facility. If the Partnership indebtedness under its senior secured credit facility 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 and NGL 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;
- 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 year ended December 31, 2010 and 2009, its percent-of-proceeds arrangements accounted for approximately 38% and 48% of its gathered natural gas volume. Under these arrangements, the Partnership generally processes natural gas from producers and remits to the producers an agreed percentage of the proceeds from the sale of residue gas and NGL products at market prices or a percentage of residue gas and NGL products at the tailgate of its 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 its 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, the Partnership s long-term success depends on its ability to obtain new sources of

supplies of natural gas and NGLs, which depends on certain factors beyond its control. Any decrease in supplies of natural gas or NGLs 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 its cash flows associated with these sources of natural gas will likely also decline over time. The Partnership s logistics assets are similarly impacted by declines in NGL supplies in the regions in which the Partnership operates as well as other regions from which it sources NGLs. To maintain or increase throughput levels on its gathering systems and the utilization rate at its processing plants and its treating and fractionation facilities, the Partnership must continually obtain new natural gas and NGL 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 that it processes and NGL products delivered to its fractionation facilities. The Partnership s ability to obtain additional sources of natural gas and NGLs 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 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 the Partnership expects this volatility to continue. Consequently, even if new natural gas reserves are discovered in areas served by the Partnership s assets, producers may choose not to develop those reserves. 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 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.

If the Partnership does not make acquisitions on economically acceptable terms or efficiently and effectively integrate the acquired assets with its asset base, its future growth will be limited.

The Partnership s ability to grow depends, in part, on its ability to make acquisitions 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, it will need to focus on third-party acquisitions and organic growth. If the Partnership is unable to make these accretive acquisitions either because the Partnership is (1) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them, (2) unable to obtain financing for these acquisitions on economically acceptable terms or (3) outbid by competitors, then its future growth and ability to increase distributions will be limited.

Any acquisition involves potential risks, including, among other things:

- operating a significantly larger combined organization and adding operations;
- difficulties in the assimilation of the assets and operations of the acquired businesses, especially if the assets acquired are in a new business segment or geographic area;
- the risk that 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;

- 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.

If these risks materialize, the acquired assets 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. If the Partnership consummates any future acquisition, 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.

The Partnership s acquisition strategy is based, in part, on its expectation of ongoing divestitures of energy assets by industry participants. A material decrease in such divestitures would limit its opportunities for future acquisitions and could adversely affect its operations and cash flows available for distribution to its unitholders.

Acquisitions may significantly increase the Partnership s size and diversify the geographic areas in which it operates. The Partnership may not achieve the desired affect from any future acquisitions.

The Partnership s 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.

One of the ways the Partnership intends to grow its business is through the construction of new midstream assets. The construction of additions or modifications to the Partnership s existing systems and the construction of new midstream assets involves numerous regulatory, environmental, political and legal uncertainties beyond the Partnership s 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 pipeline, 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, it 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 strategy requires access to new capital. Tightened capital markets or increased competition for investment opportunities could impair its ability to grow through acquisitions.

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

Weak economic conditions and the volatility and disruption in the financial markets could increase the cost of raising money in the debt and equity capital markets substantially while diminishing the availability of funds from those markets. Also, as a result of concerns about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining money from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, refused to refinance existing debt at maturity at all or on terms similar to our current debt and reduced and, in some cases, ceased to provide funding to borrowers. These factors may impair the Partnership s ability to execute its acquisition strategy.

In addition, the Partnership is experiencing increased competition for the types of assets it contemplates purchasing. Weak economic conditions and competition for asset purchases could limit the Partnership s ability to fully execute its growth strategy.

Demand for propane is seasonal and requires increases in the Partnership s 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 in its wholesale propane marketing operations, exposing it to their 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 it 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, it 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

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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, current market and economic conditions may adversely affect the Partnership s hedge counterparties ability to meet their obligations. Given the current 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 intends 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 pipelines and processing facilities become partially or fully unavailable to transport natural gas and NGLs, the Partnership s revenues could be adversely affected.

The Partnership depends upon third-party pipelines, storage and other facilities that provide delivery options to and from its pipelines and processing facilities. Since it does not own or operate these pipelines or other facilities, their continuing operation in their current manner is not within the Partnership s 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 the Partnership s business and operating results.

The Partnership competes with similar enterprises in its respective areas of operation. Some of its competitors are large oil, natural gas and natural gas liquid 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 and transportation systems that would create additional competition for the services the Partnership provides to its customers. In addition, its customers who are significant producers of natural gas may develop their own gathering, processing and transportation systems in lieu of using the Partnership s. 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 reserves dedicated to its gathering pipeline systems; therefore, volumes of natural gas on the Partnership s systems in the future could be less than it anticipates.

The Partnership typically does not obtain independent evaluations of natural gas 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 its gathering systems is less than it anticipates and the Partnership is unable to secure additional sources of natural gas, 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 of natural gas 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 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 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.

Natural Gasoline. Natural gasoline is used as a blending component for certain refined 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 s 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 the Partnership s results of operations and financial condition.

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The Partnership has significant relationships with Chevron Phillips Chemical Company LLC 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, 2010 and 2009, approximately 10% and 15% of the Partnership s consolidated revenues were derived from transactions with Chevron Phillips Chemical Company LLC (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 13.5% 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. In order to maintain its status as a partnership for United States federal income tax purposes, 90 percent or more of the gross income of the Partnership for every taxable year must be qualifying income under section 7704 of the Internal Revenue Code of 1986, as amended. 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.

Despite the fact that the Partnership is a limited partnership under Delaware law, it is possible, under certain circumstances for an entity such as the Partnership to be treated as a corporation for federal income tax purposes. Although the Partnership does not believe based upon its current operations that it is so treated, a change in the Partnership s business could cause it to be treated as a corporation for federal income tax purposes or otherwise subject it to federal income taxation as an entity.

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. At the federal level, members of Congress have recently considered legislative changes that would affect the tax treatment of certain publicly traded partnerships. Although the considered legislation would not appear to have affected the Partnership s treatment as a partnership, we are unable to predict whether any of these changes, or other proposals will be reintroduced or will ultimately be enacted. Moreover, any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Any such changes could negatively impact the value of an investment in the Partnership s common units. At the state level, because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, 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.

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 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 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 and hurricanes may cause disruptions or suspensions of the Partnership s operations, which could adversely affect its operating results.

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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 it 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 and storing, fractionating, treating, transporting and selling NGLs, 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 construction, farm and utility equipment;
- leaks of natural gas, NGLs and other hydrocarbons or losses of natural gas or NGLs as a result of the malfunction of equipment or facilities; 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, Hurricanes Katrina and Rita damaged gathering systems, processing facilities, NGL fractionators and pipelines along the Gulf Coast, including certain of the Partnership s facilities. These hurricanes disrupted the operations of the Partnership s customers in August and September 2005, which 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. The Partnership is not insured against all environmental accidents that might occur which may include toxic tort claims, other than incidents considered to be sudden and accidental. 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 it 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 coverages unavailable at any cost.

The Partnership may incur significant costs and liabilities resulting from 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;
- 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 that it will incur an aggregate cost of approximately $6.6 million between 2011 and 2013 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, the Partnership cannot predict the ultimate cost of compliance with applicable pipeline integrity management regulations, as the cost will vary significantly depending on the number and extent of any repairs found to be necessary as a result of the pipeline integrity testing. The Partnership will continue its pipeline integrity testing programs to assess and maintain the integrity of its pipelines. The results of these tests could cause the Partnership to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operations of its pipelines.

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 the Partnership to volume imbalances which, in conjunction with movements in commodity prices, could materially impact the Partnership s 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 its control. We cannot assure you that the Partnership will generate sufficient cash flow from operations or that future borrowings will be available to it under its credit agreement 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. The Partnership cannot assure you that it 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.

The Partnership s operations are subject to stringent and complex federal, state and local environmental laws and regulations governing the discharge of materials into the environment or

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otherwise relating to environmental protection. These laws include, for example, (1) the federal Clean Air Act and comparable state laws that impose obligations related to air emissions, (2) the Federal Resource Conservation and Recovery Act, as amended, (RCRA) and comparable state laws that impose requirements for the handling, storage, treatment or disposal of solid and hazardous waste from the Partnership s facilities, (3) the Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended, (CERCLA or the Superfund law) and comparable state laws that regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or at locations to which the Partnership s hazardous substances have been transported for recycling or disposal and (4) the Clean Water Act and comparable state laws that regulate discharges of wastewater from the Partnership s facilities to state and federal waters. Failure to comply with these laws and regulations or 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, including CERCLA and analogous state 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. 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 and other petroleum products, because of air emissions and water discharges related to 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. For instance, since August 2009, the Texas Commission on Environmental Quality (TCEQ) has conducted a comprehensive analysis of air emissions in the Barnett Shale area in response to reported concerns about high concentrations of benzene in the air near drilling sites and natural gas processing facilities. Partially in response to its investigation, the TCEQ has proposed new air permitting requirements for oil and gas facilities in the state, which will first become applicable to facilities located in the Barnett Shale area on April 1, 2011. These new requirements could require the Partnership to incur increased capital or operating costs. Moreover, the agency s investigations could lead to additional, more stringent air permitting requirements, increased regulation, and possible enforcement actions against producers and midstream operators in the Barnett Shale area. The Partnership is also conducting its own evaluation of air emissions at certain of its facilities in the Barnett Shale area and, as necessary, plans to conduct corrective actions at such facilities. Additionally, environmental groups have advocated increased regulation and a moratorium on the issuance of drilling permits for new natural gas wells in 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 operating and compliance costs as well as reduce the rate of production of natural gas operators with whom the Partnership has a business relationship, which could have a material adverse effect on the Partnership s 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 the Partnership 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. However, the U.S. Environmental Protection Agency (EPA) recently asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the Safe Drinking Water Act s (SDWA) Underground Injection Control Program. While the EPA has yet to take any action to enforce or implement this newly asserted regulatory authority, industry groups have filed suit challenging the EPA s recent decision. At the same time, the EPA has commenced a study of the potential adverse impact of hydraulic fracturing activities, with the initial results of the study expected to be available in late 2012. Also, legislation was introduced in the Congress to amend the SDWA to subject hydraulic fracturing operations to regulation under the SDWA and to require the disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process. Moreover, some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. 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.

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.

Venice Gathering System, L.L.C. (VGS) is a wholly owned subsidiary of Venice Energy Services Company, L.L.C. (VESCO) engaged in the business of transporting natural gas in interstate commerce, under authorization granted by and subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) under the Natural Gas Act of 1938 (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 our interest in VGS, our operations are generally exempt from FERC regulation under the NGA, but FERC regulation still affects our non-FERC jurisdictional businesses and the markets for products derived from these businesses. The NGA exempts natural gas gathering facilities from regulation by FERC as a natural gas company under the NGA. The Partnership believes that the natural gas pipelines in its gathering systems meet the traditional tests FERC has used to establish a pipeline s status as a gatherer not subject to regulation as a natural gas company. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of substantial, 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 Interstate Commerce Act (ICA) are exempt from such 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. At this time, the Partnership does not have any such proprietary lines. 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 Partnerships 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 704, requiring certain participants in the natural gas market, including intrastate

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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 720, requiring major non-interstate pipelines, defined as certain non-interstate pipelines delivering, on an annual basis, more than an average of 50 million MMBtus 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. The Partnership takes the position that at this time it and its subsidiaries are exempt from this rule as currently written. A petition for review of Order 720 is currently pending before the Court of Appeals for the Fifth Circuit, and the Partnership has no way to predict with certainty whether and to what extent Order 720 will be modified in response to the petition for review.

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.

Other FERC regulations may indirectly impact the Partnership s businesses and the markets for products derived from these businesses. FERC s policies and practices across the range of its natural gas regulatory activities, including, for example, its policies on open access transportation, gas quality, ratemaking, capacity release and market center promotion, may indirectly affect the intrastate natural gas market. In recent years, FERC has pursued pro-competitive policies in its regulation of interstate natural gas pipelines. However, we cannot assure you that FERC will continue this approach as it considers matters such as pipeline rates and rules and policies that may affect rights of access to transportation capacity. For more information regarding the regulation of our and the Partnership s operations, see Business of Targa Resources Partners LP 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 Domenici-Barton Energy Policy Act of 2005 (EP Act 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 have not been regulated by FERC as a natural gas companies under the NGA, FERC has adopted regulations that may subject certain of its otherwise non-FERC jurisdictional facilities to FERC annual reporting and daily scheduled flow and capacity posting requirements. Additional rules and legislation pertaining to those and other matters may be considered or adopted by FERC from time to time. Failure to comply with those regulations in the future could subject the Partnership to civil penalty liability. For more information regarding the regulation of our and the Partnership s operations, see Business of Targa Resources Partners LP Regulation of Operations.

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

In December 2009, the EPA determined 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 begun adopting and implementing regulations to restrict emissions of GHGs under existing provisions of the federal Clean Air Act. The EPA has already adopted two sets of rules regulating GHG emissions under the Clean Air Act, one of which requires a reduction in emissions of GHGs from motor vehicles and the other of which regulates emissions of GHGs from certain large stationary sources effective January 2, 2011. The EPA s rules relating to emissions of GHGs from large stationary sources of emissions are currently subject to a number of legal challenges, but the federal courts have thus far declined to issue any injunctions to prevent EPA from implementing or requiring state environmental agencies to implement the rules. The EPA has also adopted rules requiring the annual reporting of GHG emissions from specified large GHG emission sources in the United States beginning in 2011 for emissions occurring after January 1, 2010, as well as emissions from certain 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, beginning in 2012 for emissions occurring in 2011.

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. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall GHG emission reduction goal. The adoption of legislation or regulatory programs to reduce emissions of GHGs could require the Partnership to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. 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. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on the Partnership s business, financial condition and results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on the Partnership s financial condition and results of operations.

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 recently 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 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 within 360 days from the date of enactment. In its rulemaking under the Act, the CFTC has proposed regulations to set position limits for certain futures and option contracts in the major energy markets, and for swaps that are their economic equivalents. Certain bona fide hedging transactions or positions would be exempt from these position limits. It is not possible at this time to predict when the CFTC will finalize these regulations. The financial reform legislation may also 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 the Partnership s ability to monetize or restructure its existing derivative contracts, and increase the Partnership s 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.

The Partnership s interstate common carrier liquids pipeline is regulated by the Federal Energy Regulatory Commission.

Targa NGL Pipeline Company LLC (Targa NGL), one of the Partnership s subsidiaries, is an interstate NGL common carrier subject to regulation by FERC under the ICA. 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 20 inch diameter pipeline each of which run between Mont Belvieu, Texas and Galena Park, Texas. The eight inch and the 20 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 non-discriminatory. All shippers on these pipelines are the Partnership s subsidiaries.

Recent events in the Gulf of Mexico may adversely affect the operations of the Partnership.

In April 2010, the Transocean Deepwater Horizon drilling rig exploded and subsequently sank 130 miles south of New Orleans, Louisiana, in the ultra deep water of the Gulf of Mexico, and the resulting release of crude oil into the Gulf of Mexico was declared a Spill of National Significance by the United States Department of Homeland Security. Response actions to the release are continuing in the Gulf of Mexico. Moreover, the federal Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) has developed and adopted a series of changes to its regulations to impose a variety of new safety and operating measures intended to help prevent a similar disaster in the future. Consequently, before being allowed to resume drilling in deepwater, outer continental shelf operators must now comply with strict new safety and operating requirements and also must demonstrate the availability of adequate spill response and blowout preventer containment resources. The Partnership cannot predict with any certainty the impact of this oil spill, the extent of cleanup activities associated with this spill, or the affects of changes in regulations adopted by BOEMRE or possible changes in laws or regulations that still may be enacted in response to this spill, but this event and its aftermath could adversely affect the Partnership s operations. It is possible that the direct results of the spill and clean-up efforts could interrupt certain offshore production processed by our facilities as offshore exploration and productions operators work to comply with new legal requirements. Furthermore, additional governmental regulation of, or delays in issuance of permits for, the offshore exploration and production industry may negatively impact current or future volumes being gathered or processed by the Partnership s facilities, and may potentially reduce volumes in its Downstream logistics and marketing business.

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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 it 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. Instability in the financial markets as a result of terrorism or war could also affect the Partnership s ability to raise capital.

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USE OF PROCEEDS

We will not receive any of the net proceeds from any sale of shares of common stock by any selling stockholder. We expect to incur approximately $ million of expenses in connection with this offering, including all expenses of the selling stockholders which we have agreed to pay.

PRICE RANGE OF COMMON STOCK

Our common stock has been listed on the New York Stock Exchange since December 7, 2010 under the symbol TRGP. The following table sets forth the high and low sales prices of the common stock, as reported by the NYSE through March 31, 2011.

	Stock Prices		
Quarter Ended	**High**	**Low**	**Dividends Declared**
March 31, 2011	$ 36.70	$ 26.51	[1]
December 31, 2010	$ 28.40	$ 23.50	$ 0.06

[1] The dividend attributable to the quarter ending March 31, 2011 has not yet been declared or paid.

The last reported sales price of our common stock on the NYSE on March 31, 2011 was $36.24. As of March 31, 2011, there were approximately 220 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.

OUR DIVIDEND POLICY

General

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 (i) satisfy tax obligations associated with previous sales of assets to the Partnership, (ii) reimburse the Partnership for certain capital expenditures related to Versado and (iii) provide the Partnership with limited quarterly distribution support through 2011, all as described in more detail in Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources; and
- interest expense or principal payments on any indebtedness we incur.

On February 21, 2011, we paid a cash dividend of $0.0616 per share of common stock, or $2.6 million in total, to holders of our outstanding common stock. This dividend was pro-rated to give effect to a partial quarter following our IPO on December 10, 2010 and corresponds to a full dividend of $0.2575 per share on a quarterly basis, or $1.03 per share on an annualized basis. 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, 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.

Overview of Dividends

During the past three fiscal years, our stockholders have received dividends from us on a pro rata basis. Holders of our previously outstanding preferred stock received their pro rata share of (i) an $18 million dividend paid on

November 22, 2010; (ii) a $220 million extraordinary dividend paid in April 2010; (iii) a $200 million extraordinary dividend paid on the common stock (treating the preferred stock on a common stock equivalent basis) in April 2010; and (iv) a $445 million dividend paid in 2007. Holders of our common stock received their pro rata share of the $200 million extraordinary dividend paid in April 2010 (treating the preferred stock on a common stock equivalent basis).

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The Partnership s Cash Distribution Policy

Under the Partnership s partnership agreement, available cash is defined to generally mean, for each fiscal quarter, all cash on hand at the date of determination of available cash for that quarter less the amount of cash reserves established by the General Partner to provide for the proper conduct of the Partnership s business, to comply with applicable law or any agreement binding on the Partnership and its subsidiaries and to provide for future distributions to the Partnership s unitholders for any one or more of the upcoming four quarters. The determination of available cash takes into account the possibility of establishing cash reserves in some quarterly periods that the Partnership may use to pay cash distributions in other quarterly periods, thereby enabling it to maintain relatively consistent cash distribution levels even if the Partnership s business experiences fluctuations in its cash from operations due to seasonal and cyclical factors. The General Partner s determination of available cash also allows the Partnership to maintain reserves to provide funding for its growth opportunities. The Partnership makes its quarterly distributions from cash generated from its operations, and those distributions have grown over time as its business has grown, primarily as a result of numerous acquisitions and organic expansion projects that have been funded through external financing sources and cash from operations.

The actual cash distributions paid by the Partnership to its partners occur within 45 days after the end of each quarter. Since second quarter 2007, the Partnership has increased its quarterly cash distribution 7 times. During that time period, the Partnership has increased its quarterly distribution by 62% from $0.3375 per common unit, or $1.35 on an annualized basis, to $0.5475 per common unit, or $2.19 on an annualized basis. Please see The Partnership s Cash Distribution Policy.

SELECTED HISTORICAL FINANCIAL AND OPERATING DATA

The following table presents selected historical consolidated financial and operating data of Targa Resources Corp. for the periods and as of the dates indicated. The selected historical consolidated statement of operations and cash flow data for the years ended December 31, 2008, 2009 and 2010 and selected historical consolidated balance sheet data as of December 31, 2009 and 2010 have been derived from our audited financial statements, and that information should be read together with and is qualified in its entirety by reference to, the historical consolidated financial statements and the accompanying notes beginning on page F-1 of this prospectus.

The selected historical consolidated statement of operations and cash flow data for the years ended December 31, 2006 and 2007 and the selected historical consolidated balance sheet data as of December 31, 2006, 2007 and 2008 have been derived from audited financial statements that are not included in this prospectus.

	For the Years Ended December 31,				
	2006	2007	2008	2009	2010
	(In millions, except operating, per common share and price data)				
Revenues[1]	$ 6,132.9	$ 7,297.2	$ 7,998.9	$ 4,536.0	$ 5,469.2
Product purchases	5,440.8	6,525.5	7,218.5	3,791.1	4,687.7
Gross margin[2]	692.1	771.7	780.4	744.9	781.5
Operating expenses	222.8	247.1	275.2	235.0	260.2
Operating margin[3]	469.3	524.6	505.2	509.9	521.3
Depreciation and amortization expenses	149.7	148.1	160.9	170.3	185.5
General and administrative expenses	82.5	96.3	96.4	120.4	144.4
Other		(0.1)	13.4	2.0	(4.7)
Income from operations	237.1	280.3	234.5	217.2	196.1
Interest expense, net	(180.2)	(162.3)	(141.2)	(132.1)	(110.9)
Gain on insurance claims			18.5		
Equity in earnings of unconsolidated investments	10.0	10.1	14.0	5.0	5.4
Gain (loss) on debt repurchases			25.6	(1.5)	(17.4)
Gain on early debt extinguishment			3.6	9.7	12.5
Gain (loss) on mark-to-market derivative instruments			(1.3)	0.3	(0.4)
Other				1.2	0.5
Income tax expense:	(16.7)	(23.9)	(19.3)	(20.7)	(22.5)
Net income	50.2	104.2	134.4	79.1	63.3
Less: Net Income attributable to non controlling interest	26.0	48.1	97.1	49.8	78.3
Net income (loss) attributable to Targa Resources Corp.	24.2	56.1	37.3	29.3	(15.0)

Dividends on Series B preferred stock		(39.7)		(31.6)		(16.8)		(17.8)		(9.5)
Less:										
Undistributed earnings attributable to preferred shareholders				(24.5)		(20.5)		(11.5)		
Dividends to common equivalents										(177.8)
Net income (loss) available to common shareholders	$	(15.5)	$		$		$		$	(202.3)
Net income (loss) available per common share basic and diluted	$	(2.53)	$		$		$		$	(30.94)
Operating data:										
Plant natural gas inlet, MMcf/d(4)(5)		1,863.3		1,982.8		1,846.4		2,139.8		2,268.0
Gross NGL production, MBbl/d		106.8		106.6		101.9		118.3		121.2
Natural gas sales, BBtu/d(5)		501.2		526.5		532.1		598.4		685.1
NGL sales, MBbl/d		300.2		320.8		286.9		279.7		251.5
Condensate sales, MBbl/d		3.8		3.9		3.8		4.7		3.5

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	For the Years Ended December 31,				
	2006	2007	2008	2009	2010
	(In millions, except operating, per common share and price data)				
Average realized prices[6]:					
Natural gas, $/MMBtu	$ 6.79	$ 6.56	$ 8.20	$ 3.96	4.43
NGL, $/gal	1.02	1.18	1.38	0.79	1.06
Condensate, $/Bbl	63.67	70.01	91.28	56.32	73.68
Balance Sheet Data (at period end):					
Property plant and equipment, net	$ 2,464.5	$ 2,430.1	$ 2,617.4	$ 2,548.1	2,509.0
Total assets	3,458.0	3,795.1	3,641.8	3,367.5	3,393.8
Long-term debt less current maturities	1,471.9	1,867.8	1,976.5	1,593.5	1,534.7
Convertible cumulative participating Series B preferred stock	687.2	273.8	290.6	308.4	
Total owners equity	(71.5)	574.1	822.0	754.9	1,036.1
Cash Flow Data:					
Net cash provided by (used in):					
Operating activities	$ 269.5	$ 190.6	$ 390.7	$ 335.8	$ 208.5
Investing activities	(117.8)	(95.9)	(206.7)	(59.3)	(134.6)
Financing activities	(50.4)	(59.5)	0.9	(386.9)	(137.9)

(1) Includes business interruption insurance proceeds of $10.7 million, $7.3 million, $32.9 million, $21.5 million and $6 million for the years ended December 31, 2006, 2007, 2008, 2009 and 2010.

(2) Gross margin is a non-GAAP financial measure and is discussed under Management s Discussion and Analysis of Financial Condition and Results of Operations How We Evaluate Our Operations and How We Evaluate the Partnership s Operations.

(3) Operating margin is a non-GAAP financial measure and is discussed under Management s Discussion and Analysis of Financial Condition and Results of Operations How We Evaluate Our Operations and How We Evaluate the Partnership s Operations.

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

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

(6) Average realized prices include the impact of hedging activities.

MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

You should read the following discussion of our financial condition and results of operations in conjunction with the historical consolidated financial statements and notes thereto included elsewhere in this prospectus. For more detailed information regarding the basis of presentation for the following information, you should read the notes to the historical financial statements included elsewhere in this prospectus. In addition, you should read Forward-Looking Statements and Risk Factors for information regarding certain risks inherent in our and the Partnership s business.

Overview

Financial Presentation

An indirect subsidiary of ours is the sole member of the General Partner. 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, our financial results are combined with the Partnership s financial results 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 non-controlling 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.

General

The Partnership is a leading provider of midstream natural gas and NGL services in the United States. The Partnership is engaged in the business of gathering, compressing, treating, processing and selling natural gas, storing, fractionating, treating, transporting and selling NGLs and NGL products and storing and terminaling refined petroleum products and crude oil. It operates through two divisions: the Natural Gas Gathering and Processing division and the Logistics and Marketing division.

As a result of the conveyance of all of our remaining operating assets to the Partnership in September 2010, we currently 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 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: non-controlling interests in the Partnership, our separate debt obligations, certain general and administrative costs applicable to us as a separate public company, and certain non-operating assets and liabilities that we retained and were not included in the asset conveyances to the Partnership.

Factors That Significantly Affect Our Results

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

As of March 31, 2011, 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 IDRs; and

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11,645,659 of the 84,756,009 outstanding common units of the Partnership, representing 13.7% of the limited partnership interest.

Cash Distributions

The following table sets forth the historical distributions that the Partnership has paid in respect of our 2% general partner interest, the associated IDRs and actual common units that we held during the periods indicated. The amount of these Partnership distributions available for distribution to us and the Partnership s shareholders will be after reserves are established for the Partnership s capital contributions, debt service requirements, general, administrative and other expenses, future distributions and other miscellaneous uses of cash. We will not distribute all of the cash that we receive from the Partnership to our shareholders, as we will establish reserves for capital contributions, debt service requirements, general, administrative and other expenses, future distributions and other miscellaneous uses of cash.

	Cash Distribution Declared Per Limited Partner Unit	Limited Partner Units Outstanding	Actual Cash Distributions Total	Limited Partner Units	General Partner Interest	IDRs	Distributions to Targa Resources Corp.[1]
	(In millions except Cash Distributions Per Limited Partner Unit)						
2007							
First Quarter	$ 0.16875	30.9	$ 5.3	$ 5.2	$ 0.1	$	$ 2.1
Second Quarter	0.33750	30.9	10.6	10.4	0.2		4.1
Third Quarter	0.33750	44.4	15.3	15.0	0.3		4.2
Fourth Quarter	0.39750	46.2	18.9	18.4	0.4	0.1	5.1
2008							
First Quarter	$ 0.41750	46.2	$ 19.9	$ 19.3	$ 0.4	$ 0.2	$ 5.5
Second Quarter	0.51250	46.2	25.9	23.7	0.5	1.7	8.2
Third Quarter	0.51750	46.2	26.3	23.9	0.5	1.9	8.4
Fourth Quarter	0.51750	46.2	26.4	24.0	0.5	1.9	8.4
2009							
First Quarter	$ 0.51750	46.2	$ 26.3	$ 23.9	$ 0.5	$ 1.9	$ 8.4
Second Quarter	0.51750	46.2	26.4	23.9	0.5	2.0	8.5
Third Quarter	0.51750	61.6	35.2	31.9	0.7	2.6	13.7
Fourth Quarter	0.51750	68.0	38.8	35.2	0.8	2.8	14.0
2010							
First Quarter	$ 0.51750	68.0	$ 38.8	$ 35.2	$ 0.8	$ 2.8	$ 9.6
Second Quarter	0.52750	68.0	40.2	35.9	0.8	3.5	10.4
Third Quarter	0.53750	75.5	46.1	40.6	0.9	4.6	11.8
Fourth Quarter	0.54750	84.7	53.5	46.4	1.1	6.0	13.5

(1) Distributions to Targa are comprised of amounts attributable to Targa s (i) limited partner units, (ii) general partner units, and (iii) IDRs.

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 and processing and logistics assets, its contract terms and changes in commodity prices.

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.

Contract Terms and 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 natural gas gathering and processing segment can also have a significant impact on its profitability, especially those that create exposure to changes in energy prices.

Set forth below is a table summarizing the contract mix of the Partnership s natural gas gathering and processing division for 2010 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	38%	Decreases in natural gas and or NGL prices generate decreases in operating margins.
Fee-Based	7%	No direct impact from commodity price movements.
Wellhead Purchases / Keep-Whole	17%	Increases in natural gas prices relative to NGL prices generate decreases in operating margin.
Hybrid	38%	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.

The Partnership generally prefers to enter into contracts with less commodity price sensitivity including fee-based and percent-of-proceeds arrangements. However, negotiated contract terms are based upon a variety of factors, including natural gas quality, geographic location, the competitive commodity and 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, and 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 as well as 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 take -or -pay contracts were not readily available. Currently, demand for fractionation services is relatively high, rates have increased, contract terms or 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 margin-based 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, 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 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 Quantitative and Qualitative Disclosures About Market Risk Commodity Price Risk.

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General Trends and Outlook

We expect the midstream energy business environment to continue to be affected by the following key trends: demand for our services, significant relationships, 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 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 compared to natural gas prices has caused producers in and around the Partnership s natural gas 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. 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 its 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.

Significant Relationships. The following table lists the counterparties that account for more than 10% of the Partnership s consolidated sales and consolidated product purchases.

	Year Ended December 31,		
	2008	2009	2010
% of consolidated revenues CPC	19%	15%	10%
% of consolidated product purchases Louis Dreyfus Energy Services L.P	9%	11%	10%

No other third party customer accounted for more than 10% of our consolidated revenues or consolidated product purchases during these periods.

Commodity Prices. Current forward commodity prices for the January 2011 through December 2011 period show natural gas and crude oil prices strengthening while NGL prices weaken on an absolute price basis and as a percentage of crude oil. 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.

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 the Partnership 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. As a result of our conveyances of all of our remaining operating assets to the Partnership we 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 non-controlling 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 the asset conveyances to the Partnership, and certain general and administrative costs applicable to us as a separate public company.

How We Evaluate the Partnership s Operations

The Partnership s profitability is a function of the difference between the revenues it receives from our operations, including revenues from the natural gas, NGLs and condensate it sells, and the costs associated with conducting its operations, including the costs of wellhead natural gas and mixed NGLs that it purchases as well as operating and general and administrative costs, and the impact of the Partnership s 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 natural gas and NGLs, and the volume of 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 and changes in its customer mix.

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

Throughput Volumes, Facility Efficiencies and Fuel Consumption. The Partnership s profitability is impacted by its ability to add new sources of natural gas supply to offset the natural decline of existing volumes from natural gas wells that are connected to its gathering and processing systems. This is achieved by connecting new wells and adding new volumes in existing areas of production as well as by capturing natural gas supplies currently gathered by third parties. Similarly, the Partnership s profitability is impacted

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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 gathering or fractionation facilities.

In addition, the Partnership seeks to increase operating margins by limiting volume losses and reducing fuel consumption by increasing compression efficiency. With its gathering systems extensive use of remote monitoring capabilities, the Partnership monitors the volumes of 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, which helps 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 a specific asset. Labor, ad valorem taxes, repair and maintenance, utilities and contract services comprise the most significant portion of the Partnership s operating expenses. These expenses 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.

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

Operating Margin. Operating margin is an important performance measure of the core profitability of the Partnership s operations. We define operating margin as gross margin less operating expenses. Natural gas and NGL sales revenue includes settlement gains and losses on commodity hedges.

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. You should not consider gross margin and operating margin in isolation or as a substitute for analysis of our results as reported under GAAP. Because gross margin and operating margin exclude some, but not all, items that affect net income and are defined differently by different companies in our industry, our definition of gross margin and operating margin may not be comparable to similarly titled measures of other companies, thereby diminishing their utility.

Targa senior 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

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measures by us and by external users of our financial statements, including such investors, commercial banks and others, 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.

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

	Year Ended December 31,		
	2008	**2009**	**2010**
	(In millions)		
Reconciliation of Targa Resources Partners LP s gross margin and operating margin to net income (loss):			
Gross margin	$ 812.9	$ 710.9	$ 772.2
Operating expenses	(274.3)	(234.4)	(259.5)
Operating margin	538.6	476.5	512.7
Depreciation and amortization expenses	(156.8)	(166.7)	(176.2)
General and administrative expenses	(97.3)	(118.5)	(122.4)
Other operating income (loss)	(19.3)	3.7	3.3
Interest expense, net	(156.1)	(159.8)	(110.8)
Income tax expense	(2.9)	(1.2)	(4.0)
Gain (loss) on sale of assets	5.9	(0.1)	
Gain (loss) on debt repurchases	13.1	(1.5)	
Risk management activities	76.4	(30.9)	26.0
Equity in earnings of unconsolidated investments	14.0	5.0	5.4
Gain on insurance claims	18.5		
Other, net	1.1	0.7	
Partnership net income (loss)	$ 235.2	$ 7.2	$ 134.0

Adjusted EBITDA. The Partnership defines Adjusted EBITDA as net income before interest, income taxes, depreciation and amortization, gains or losses on debt repurchases and non-cash income or loss 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.

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 and GAAP net income. Adjusted EBITDA is not a presentation made in accordance with GAAP and has important limitations as an analytical tool. You 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

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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.

The Partnership 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.

	Year Ended December 31,		
	2008	2009	2010
		(In millions)	
Reconciliation of Targa Resources Partners LP net cash provided by operating activities to Adjusted EBITDA:			
Net cash provided by operating activities	$ 550.2	$ 422.9	$ 371.2
Net income attributable to noncontrolling interest	(33.1)	(19.3)	(24.9)
Interest expense, net[(1)]	34.7	44.8	74.8
Gain (loss) on debt repurchases	13.1	(1.5)	
Termination of commodity derivatives	87.4		
Current income tax expense	0.8	0.3	2.8
Other[(2)]	3.4	(10.6)	(14.7)
Changes in operating assets and liabilities which used (provided) cash:			
Accounts receivable and other assets	(890.8)	57.0	71.2
Accounts payable and other liabilities	655.3	(93.0)	(84.3)
Partnership adjusted EBITDA	$ 421.0	$ 400.6	$ 396.1

(1) Net of amortization of debt issuance costs of $2.1 million, $3.9 million and $6.6 million and amortization of discount and premium included in interest expense of $2.1 million, $3.4 million and $0.1 million for 2008, 2009 and 2010. Excludes affiliate and allocated interest expense.

(2) Includes non-controlling interest percentage of our consolidated investment s depreciation, interest expense and maintenance capital expenditures , equity earnings from unconsolidated investments net of distributions, accretion expense associated with asset retirement obligations, amortization of stock based compensation and gain (loss) on sale of assets.

	Year Ended December 31,		
	2008	2009	2010
		(In millions)	
Reconciliation of net income (loss) attributable to Targa Resources Partners LP to Adjusted EBITDA:			
Net income attributable to Targa Resources Partners LP	$ 202.1	$ (12.1)	$ 109.1
Add:			
Interest expense, net[(1)]	156.1	159.8	110.8
Income tax expense	2.9	1.2	4.0

Depreciation and amortization expenses	156.8	166.7	176.2
Risk management activities	(85.4)	95.5	6.4
Noncontrolling interest adjustment	(11.5)	(10.5)	(10.4)
Partnership adjusted EBITDA	$ 421.0	$ 400.6	$ 396.1

(1) Includes affiliate and allocated interest expense.

Consolidated Results of Operations

Our management uses a variety of financial and operational measurements to analyze our performance. These measurements include both measures for the Partnership activities and measures for the Parent. Partnership measures include gross margin, operating margin, operating expenses, plant

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inlet, gross NGL production, adjusted EBITDA and distributable cash flow, among others. For a discussion of these measures, see Management s Discussion and Analysis of Financial Condition and Results of Operations How We Evaluate the Partnership s Operations. The following table and discussion is a summary of our consolidated results of operations for the three years ended December 31, 2010.

	Year Ended December 31,			Variance			
				2009 vs. 2008		2010 vs. 2009	
	2008	2009	2010	$ Change	% Change	$ Change	% Change
	(In millions, except operating and price amounts)						
Revenues(1)	$ 7,998.9	$ 4,536.0	$ 5,469.2	$ (3,462.9)	(43.3)%	$ 933.2	20.57%
Product purchases	7,218.5	3,791.1	4,687.7	(3,427.4)	(47.5)%	896.6	23.65%
Gross margin	780.4	744.9	781.5	(35.5)	(4.5)%	36.6	4.91%
Operating expenses	275.2	235.0	260.2	(40.2)	(14.6)%	25.2	10.72%
Operating margin	505.2	509.9	521.3	4.7	0.93%	11.4	2.24%
Depreciation and amortization expenses	160.9	170.3	185.5	9.4	5.84%	15.2	8.93%
General and administrative expenses	96.4	120.4	144.4	24.0	24.9%	24.0	19.93%
Other	13.4	2.0	(4.7)	(11.4)	(85.1)%	(6.7)	(335.0)%
Income from operations	234.5	217.2	196.1	(17.3)	(7.4)%	(21.1)	(9.7)%
Interest expense, net	(141.2)	(132.1)	(110.9)	9.1	(6.4)%	21.2	(16.0)%
Gain on insurance claims	18.5			(18.5)	(100.0)%		*
Equity in earnings of unconsolidated investments	14.0	5.0	5.4	(9.0)	(64.3)%	0.4	8%
Gain (loss) on debt repurchases	25.6	(1.5)	(17.4)	(27.1)	(105.9)%	(15.9)	1,060%
Gain on early debt extinguishment	3.6	9.7	12.5	6.1	169.44%	2.8	28.87%
Gain (loss) on mark-to-market derivative instruments	(1.3)	0.3	(0.4)	1.6	(123.1)%	(0.7)	(233.3)%
Other		1.2	0.5	1.2	*	(0.7)	(58.3)%
Income tax expense	(19.3)	(20.7)	(22.5)	(1.4)	7.25%	(1.8)	8.7%
Net income	134.4	79.1	63.3	(55.3)	(41.1)%	(15.8)	(20.0)%
Less: Net income attributable to noncontrolling interest	97.1	49.8	78.3	(47.3)	(48.7)%	28.5	57.23%

Net income (loss) attributable to Targa Resources Corp.	37.3	29.3	(15.0)	(8.0)	(21.4)%	(44.3)	(151.2)%
Dividends on Series B preferred stock	(16.8)	(17.8)	(9.5)	(1.0)	5.95%	8.3	(46.6)%
Less:							
Undistributed earnings attributable to preferred shareholders	(20.5)	(11.5)		9.0	(43.9)%	11.5	(100)%
Dividends to common equivalents			(177.8)			(177.8)	
Net income (loss) available to common shareholders	$	$	(202.3)	$	$	$ (202.3)	
Operating statistics:							
Plant natural gas inlet, MMcf/d(2)(3)	1,846.4	2,139.8	2,268.0	293.4	15.9%	128.2	5.99%
Gross NGL production, MBbl/d	101.9	118.3	121.2	16.4	16.1%	2.9	2.45%
Natural gas sales, BBtu/d(3)	532.1	598.4	685.1	66.3	12.5%	86.7	14.49%
NGL sales, MBbl/d	286.9	279.7	251.5	(7.2)	(3)%	(28.2)	(10.1)%
Condensate sales, MBbl/d	3.8	4.7	3.5	0.9	23.7%	(1.2)	(25.5)%
Average realized prices:(4)							
Natural gas, $/MMBtu	$ 8.20	$ 3.96	4.43	$ (4.24)	(51.8)%	$ 0.48	12%
NGL, $/gal	1.38	0.79	1.06	(0.59)	(43)%	0.27	34.7%
Condensate, $/Bbl	91.28	56.32	73.68	(34.96)	(38)%	17.37	30.8%
Balance Sheet Data (at end of period):							
Property, plant and equipment, net	$ 2,617.4	$ 2,548.1	$ 2,509.0	$ (69.3)	(3)%	$ (39.1)	(2)%
Total assets	3,641.8	3,367.5	3,393.8	(274.3)	(8)%	22.7	0.7%
Long-term debt less current maturities	1,976.5	1,593.5	1,534.7	(383.0)	(19)%	(58.8)	(4)%
Convertible cumulative participating Series B preferred stock	290.6	308.4		17.8	6.1%	(308.4)	(100)%
Total owners equity	822.0	754.9	1,036.1	(67.1)	(8)%	288.1	38.2%
Cash Flow Data:							
Net cash provided by (used in):							
Operating activities	$ 390.7	$ 335.8	$ 208.5	$ (54.9)	(14.1)%	$ (127.3)	(37.9)%
Investing activities	(206.7)	(59.3)	(134.6)	147.4	(71.3)%	(75.3)	127.0%

Financing activities	0.9	(386.9)	(137.9)	(387.8)	(43,089)%	249.0	(64.4)%

(1) Includes business interruption insurance proceeds of $32.9 million, $21.5 million and $6.0 million for the years ended December 31, 2008, 2009 and 2010.

(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 include the impact of hedging activities.

* Not meaningful

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

Revenue decreased $3,462.9 million due to lower commodity prices ($3,516.5 million), lower NGL sales volumes ($169.4 million) and lower business interruption insurance proceeds ($11.4 million) offset by higher natural gas and condensate sales volumes ($222.1 million) and higher fee-based and other revenues ($12.3 million).

The $35.5 million decrease in gross margin reflects lower revenue ($3,462.9 million) offset by a reduction in product purchase costs ($3,427.4 million). For additional information regarding the period to period changes in our gross margins, see Results of Operations By Segment.

The decrease in operating expenses was primarily due to lower fuel, utilities and catalyst expenses ($20.6 million), lower maintenance and supplies expenses ($20.6 million), and lower contract labor costs ($7.8 million), partially offset by a lower level of cost recovery billings to others ($6.5 million). Year over year comparisons of operating expenses are affected by the consolidation of VESCO starting August 1, 2008, following our acquisition of majority ownership in this operation. Had VESCO been consolidated for all of 2008, operating expenses would have been $17.1 million higher for 2008. See Results of Operations By Segment for additional discussion regarding changes in operating expenses.

The increase in depreciation and amortization expenses is primarily attributable to assets acquired in 2008 that had a full period of depreciation and capital expenditures in 2009 of $170.3 million.

The increase in general and administrative expenses was primarily due to higher compensation related expenses ($17.0 million) and increased insurance expenses ($6.0 million), reflecting higher property casualty premiums following significant 2008 Gulf Coast hurricane activity.

Other operating items were an overall loss of $2.0 million during 2009 versus a loss of $13.4 million during 2008, when we recorded a $19.3 million loss provision for property damage from Hurricanes Gustav and Ike net of expected insurance recoveries. During 2009 the loss provision was reduced by $3.7 million. A $5.9 million gain from a like-kind exchange of pipeline assets was also realized during 2008.

The decrease in interest expense is due to reduction of debt levels due to our sale of certain of our assets to the Partnership coupled with sales of Partnership equity and increased debt at the Partnership. See Liquidity and Capital Resources for information regarding our outstanding debt obligations.

The decrease in equity in earnings of unconsolidated investments is due to our acquisition of majority ownership in and consolidation of VESCO beginning August 1, 2008.

The net decrease in gains from debt transactions includes a $27.1 million decrease in gain on debt repurchases partially offset by a $6.1 million increase in gain on debt extinguishment. See Liquidity and Capital Resources for information regarding our outstanding debt obligations.

The increase in gain on mark-to-market derivative instruments was due to favorable changes in commodity prices and our adjusting $1.6 million in fair value of certain contracts with Lehman Brothers Commodity Services Inc. to zero as a result of the Lehman Brothers bankruptcy filing.

Net income attributable to noncontrolling interests decreased from $97.1 million for the twelve months ended December 31, 2008 to $49.8 million for the twelve months ended December 31, 2009. $20.0 million of the decrease was due to decreased net income subject to noncontrolling interest for CBF and Versado, partially offset by an increase of $6.2 million for VESCO due to the purchase of Chevron s interest in August 2008. In addition, net income subject to noncontrolling interest for the Partnership decreased in 2009, partially offset by the September 2009 dropdown of the Downstream Business into the Partnership. In addition, our ownership in the Partnership increased in 2009 to 33.9% versus 26.5% at the prior year-end due to the impact of the Downstream dropdown, partially offset by the Partnership sales of common units in August 2009. After adjusting for the impact of the IDRs, our weighted average percentages of net income were 40.5% in 2009 and 30.1% in 2008.

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

Revenue increased $933.2 million due to higher realized commodity prices ($1,200.9 million) offset by lower sales volumes ($247.6 million), lower fee-based and other revenues ($5.5 million) and lower business interruption insurance proceeds ($15.5 million).

The $36.6 million increase in gross margin reflects higher revenues ($933.2 million) offset by higher product purchase costs ($896.7 million). For additional information regarding the period to period changes in our gross margins, see Results of Operations By Segment.

The $25.2 million increase in operating expenses was primarily attributable to increased compensation and benefits expense ($14.6 million), increased maintenance costs and utility costs of ($14.5 million), partially offset by lower contract services and professional fees of $6.1 million. See Results of Operations By Segment for additional discussion regarding changes in operating expenses.

The increase in depreciation and amortization expenses of $15.2 million is attributable to a $10.8 million impairment charge related to idled terminal and processing assets as well as assets acquired in 2009 that have a full period of depreciation in 2010 and capital expenditures in 2010 of $147.2 million.

General and administrative expenses increased $24.0 million reflecting increased professional services and special compensation expense related to our December IPO.

Other operating items were an overall gain of $4.7 million during 2010 versus an overall loss of $2.0 million during 2009. This improvement primarily reflects lower project abandonment costs during 2010. Both years included income related to favorable outcomes on hurricane repair outlays and insurance recoveries.

The decrease in interest expense of $21.2 million is due to reductions in our total outstanding indebtedness primarily funded by equity issuances by the Partnership. See Liquidity and Capital Resources for information regarding our outstanding debt obligations.

The effects of an overall net loss on debt retirements lowered pre-tax earnings by $13.1 million.

Net income attributable to noncontrolling interests increased from $49.8 million for the twelve months ended December 31, 2009 to $78.3 million for the twelve months ended December 31, 2010. $5.5 million of the increase was due to increased net income subject to noncontrolling interest for CBF, Versado and VESCO. In addition, net income subject to noncontrolling interest for the Partnership increased in 2010, primarily due to the impact of the full year ownership of the Downstream Business by the Partnership, as well as the partial year impact of the 2010 dropdowns of assets into the Partnership. In addition, our ownership interest in the Partnership decreased in 2010 due to the impact of the secondary sales of our units to the public in April 2010, as well as the Partnership s sales of common units in January and August 2010. At December 31, 2010 our ownership in the Partnership was 17.1% versus 33.9% at year-end 2009. After adjusting for the impact of the incentive distribution rights, our weighted average percentages of net income were 35.5% in 2010 and 40.5% in 2009.

Dividends were paid to our Series B Preferred shareholders in April 2010 and November 2010, which reduced the accretive value of these shares. At our IPO, the outstanding Series B Preferred shares converted to common shares.

Consolidated Results of Operations Partnership versus Non-Partnership

The following table breaks down the consolidated results of operations for the three years ended December 31, 2010 into Partnership and our standalone (TRC Non-Partnership) financial results.

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Partnership results are presented on a common control accounting basis. A discussion of the TRC Non-Partnership financial results follows this table.

	2008			2009			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 partn
					(In millions)				
ues	$ 7,998.9	$ 8,030.1	$ (31.2)	$ 4,536.0	$ 4,503.8	$ 32.2	$ 5,469.2	$ 5,460.2	$
nd Expenses:									
t purchases	7,218.5	7,217.2	1.3	3,791.1	3,792.9	(1.8)	4,687.7	4,688.0	
ng expenses	275.2	274.3	0.9	235.0	234.4	0.6	260.2	259.5	
iation and amortization	160.9	156.8	4.1	170.3	166.7	3.6	185.5	176.2	
l and administrative	96.4	97.3	(0.9)	120.4	118.5	1.9	144.4	122.4	
	13.4	13.4		2.0	(3.6)	5.6	(4.7)	(3.3)	
	7,764.4	7,759.0	5.4	4,318.8	4,308.9	9.9	5,273.1	5,242.8	
e from operations	234.5	271.1	(36.6)	217.2	194.9	22.3	196.1	217.4	
ncome (expense):									
t expense, net Third	(141.2)	(38.9)	(102.3)	(132.1)	(52.1)	(80.0)	(110.9)	(81.4)	
t expense Intercompany		(117.2)	117.2		(107.7)	107.7		(29.4)	
in earnings of olidated investments	14.0	14.0		5.0	5.0		5.4	5.4	
oss) on debt ases				(1.5)	(1.5)		(17.4)		
oss) on debt ishment	29.2	13.1	16.1	9.7		9.7	12.5		

n insurance claims	18.5	18.5							
oss) on mark-to-market ive instruments	(1.3)	76.4	(77.7)	0.3	(30.9)	31.2	(0.4)	26.0	
ncome (expense)		1.1	(1.1)	1.2	0.7	0.5	0.5		
e before income taxes	153.7	238.1	(84.4)	99.8	8.4	91.4	85.8	138.0	
e tax (expense) benefit									
t	(1.3)	(0.8)	(0.5)	(1.6)	(0.3)	(1.3)	10.6	(2.8)	
ed	(18.0)	(2.1)	(15.9)	(19.1)	(0.9)	(18.2)	(33.1)	(1.2)	
	(19.3)	(2.9)	(16.4)	(20.7)	(1.2)	(19.5)	(22.5)	(4.0)	
ome (loss)	134.4	235.2	(100.8)	79.1	7.2	71.9	63.3	134.0	
let income attributable controlling interest	97.1	33.1	64.0	49.8	19.3	30.5	78.3	24.9	
ome (loss) attributable	$ 37.3	$ 202.1	$ (164.8)	$ 29.3	$ (12.1)	$ 41.4	$ (15.0)	$ 109.1	$ (

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The following table provides details of the TRC Non-Partnership results displayed in the table above:

	2008	2009	2010
		(In millions)	
Revenues			
Business interruption revenues (post dropdown) retained by TRC Non-Partnership	$	$ 8.2	$ 6.0
Settlements on pre-dropdown derivatives not qualifying for hedge treatment in separate Partnership financial statements	(31.2)	24.0	3.0
Costs & Expenses			
Product purchases for assets excluded from dropdown transactions	1.3	(1.8)	(0.3)
Operating expenses for assets excluded from dropdown transactions	0.9	0.6	0.7
Depreciation on excluded and corporate assets	4.1	3.6	9.3
G&A expenses retained by TRC Non-Partnership	(0.9)	1.9	22.0
Project abandonments and loss (gain) on property retirements and sales related to excluded assets		5.6	(1.4)
Other income (expense)			
Interest expense on TRC Non-Partnership debt	(102.3)	(80.0)	(29.5)
Interest income on intercompany debt	117.2	107.7	29.4
Gain (loss) on purchases and extinguishments of TRC Non-Partnership debt obligations	16.1	9.7	(4.9)
Reversal of Partnership mark-to-market derivatives gain (losses) qualifying for hedge accounting by Parent	(77.7)	31.2	(26.4)
Other	(1.1)	0.5	0.5
Income tax expense (benefit) related to profits and losses taxed at the TRC Non-Partnership level and impact of dropdown transactions	(16.4)	(19.5)	(18.5)
Net income attributable to noncontrolling interest in the Partnership	64.0	30.5	53.4

Results of Operations By Segment

We have segregated the following segment operating margin between Partnership and TRC Non-Partnership activities. Partnership activities have been presented on a common control accounting basis which reflects the dropdown transactions as if they occurred in prior periods. TRC Non-Partnership 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.

	Partnership						
Year Ended	Field Gathering and Processing	Coastal Gathering and Processing	Logistics Assets	Marketing and Distribution	Other	TRC Non-Partnership	Consolidated Operating Margin
				(In millions)			
December 31, 2008	$ 385.4	$ 105.4	$ 40.1	$ 41.3	$ (33.6)	$ (33.4)	$ 505.2
December 31, 2009	183.2	89.7	74.3	83.0	46.3	33.4	509.9

December 31, 2010	236.6	107.8	83.8	80.5	4.0	8.6	521.3

A discussion of the Partnership segment results follows.

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Results of Operations of the Partnership By Segment

Natural Gas Gathering and Processing Division

Field Gathering and Processing

	Year Ended December 31,			Variance 2009 vs. 2008		Variance 2010 vs. 2009	
	2008	2009	2010	$ Change	% Change	$ Change	% Change
	($ in millions except average realized prices)						
Gross margin	$ 489.5	$ 268.3	$ 338.8	$ (221.2)	(45)%	$ 70.5	26%
Operating expenses	104.1	85.1	102.2	(19.0)	(18)%	17.1	20%
Operating margin	$ 385.4	$ 183.2	$ 236.6	$ (202.2)	(52)%	$ 53.4	29%
Operating statistics:							
Plant natural gas inlet, MMcf/d	584.1	581.9	587.7	(2.2)	(0)%	5.8	1%
Gross NGL production, MBbl/d	68.0	69.8	71.2	(1.8)	3%	1.4	2%
Natural gas sales, BBtu/d(1)	296.2	219.6	258.6	(76.6)	(26)%	39.0	18%
NGL sales, MBbl/d(1)	54.1	56.2	56.6	2.1	4%	0.4	1%
Condensate sales, MBbl/d(1)	3.5	3.2	2.9	(0.3)	9%	(0.3)	(9)%
Average realized prices:							
Natural gas, $/MMBtu	$ 7.55	$ 3.69	$ 4.11	$ (3.86)	(51)%	$ 0.42	11%
NGL, $/gal	1.21	0.69	0.93	(0.52)	(43)%	0.24	35%
Condensate, $/Bbl	86.51	55.84	75.48	(30.67)	(35)%	19.64	35%

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

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

The $221.2 million decrease in gross margin for 2009 was due to lower commodity sales prices ($853.9 million) and lower natural gas and condensate sales volumes ($157.2 million) offset by higher NGL sales volumes ($36.1 million), higher fee based and other revenue ($0.1 million) and lower product purchases ($753.8 million). The increased NGL sales volumes were due primarily to higher NGL production.

The decrease in operating expenses was primarily due to lower maintenance and supplies expenses ($8.4 million), lower contract services and professional fees ($4.4 million), and lower fuel, utilities and catalysts expenses ($3.2 million).

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

The $70.5 million increase in gross margin for 2010 was primarily due to higher commodity sales prices ($303.9 million) and higher natural gas and NGL sales volumes ($22.6 million) offset by lower condensate sales volumes ($6.8 million), higher fee based and other revenue ($4.5 million) and higher product purchases ($253.6 million). The increased natural gas and NGL sales volumes were due primarily to higher natural gas and NGL production.

The increase in operating expenses was primarily due to higher system maintenance expenses ($8.2 million), higher compensation and benefit costs ($4.7 million) and higher contract and professional service expenses ($2.0 million).

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Coastal Gathering and Processing

	Year Ended December 31,			Variance 2009 vs. 2008		Variance 2010 vs. 2009	
	2008	2009	2010	$ Change	% Change	$ Change	% Change
	($ in millions except average realized prices)						
Gross margin	$ 136.5	$ 132.7	$ 151.2	$ (3.8)	(3)%	$ 18.5	14%
Operating expenses	31.1	43.0	43.4	11.9	38%	0.4	1%
Operating margin	$ 105.4	$ 89.7	$ 107.8	(15.7)	(15)%	18.1	20%
Operating statistics:							
Plant natural gas inlet, MMcf/d(2)	1,262.4	1,557.8	1,680.3	295.4	23%	122.5	8%
Gross NGL production, MBbl/d	33.9	48.5	50.1	14.6	43%	1.6	3%
Natural gas sales, BBtu/d(1)	239.4	258.4	293.6	19.0	8%	35.2	14%
NGL sales, MBbl/d(1)	31.7	40.6	43.7	8.9	28%	3.1	8%
Condensate sales, MBbl/d(1)	1.5	1.6	0.5	0.1	7%	(1.1)	(69)%
Average realized prices:							
Natural gas, $/MMBtu	$ 9.00	$ 4.00	$ 4.48	$ (5.00)	(56)%	$ 0.48	12%
NGL, $/gal	1.34	0.77	1.03	(0.57)	(43)%	0.26	34%
Condensate, $/Bbl	90.10	53.31	78.82	(36.79)	(41)%	25.51	48%

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

(2) The majority of the Partnership s straddle plant volumes are gathered on third party offshore pipeline systems and delivered to the plant inlets.

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

The $3.8 million decrease in gross margin for 2009 is primarily due to lower commodity realization prices ($847.7 million) and lower business interruption proceeds ($3.4 million) offset by higher commodity sales volumes ($246.0 million) as a result of the recovery of operations after Hurricanes Gustav and Ike, reduced product purchase costs ($596.7 million) and higher fee-based and other income ($4.6 million). VESCO has been consolidated in our financials since we purchased Chevron s interest in August 2008, giving us a controlling interest from that date forward. Had VESCO been consolidated for the entire period, gross margin for 2008 would have been $43.6 million.

The increase in operating expenses was primarily due to a full year of operating expenses from VESCO in 2009, as compared with five months of operating expenses from VESCO in 2008 due to the Partnership s acquisition of majority ownership in and consolidation of VESCO on August 1, 2008. Had VESCO been consolidated for the entire period, operating expenses for 2008 would have been $17.8 million higher and our Coastal Gathering and Processing segment would have reported reductions in aggregate operating expense levels during 2009 as was the case with the

Partnership s other segments.

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

The $18.5 million increase in gross margin for 2010 is primarily due to an increase in commodity sales prices ($230.3 million) and an increase in natural gas and NGL sales volumes ($88.3 million) offset by decreases in condensate sales volumes ($21.8 million) and fee-based and other revenues ($11.3 million) and an increase in commodity sales purchases ($266.8 million). Natural gas sales volumes increased due to increased sales to other segments for resale partially offset by a small decrease in demand from the Partnership s industrial customers. NGL, natural gas and inlet sales volumes increased primarily because the straddle plants were recovering operations in the first two quarters of 2009 after Hurricanes Gustav and Ike disrupted operations in 2008.

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Logistics and Marketing Division

Logistics Assets

	Year Ended December 31,			Variance			
				2009 vs. 2008		2010 vs. 2009	
	2008	2009	2010	$ Change	% Change	$ Change	% Change
	($ in millions except average realized prices)						
Gross margin	$ 172.5	$ 156.2	$ 172.3	$ (16.3)	(9)%	$ 16.1	10%
Operating expenses	132.4	81.9	88.5	(50.5)	(38)%	6.6	8%
Operating margin	$ 40.1	$ 74.3	$ 83.8	$ 34.2	85%	$ 9.5	13%
Operating statistics:							
Fractionation volumes, MBbl/d	212.2	217.2	230.8	5.0	2%	13.6	6%
LSNG treating volumes, MBbl/d	20.7	21.9	18.0	1.2	6%	(3.9)	(18)%

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

The $16.3 million decrease in gross margin for 2009 was due to lower fractionation and treating revenue ($20.9 million) due to lower fees offset by higher other fee-based and other revenue ($4.6 million).

The decrease in operating expenses was primarily due to lower fuel and utilities expenses ($43.2 million), lower maintenance and supplies expenses ($4.7 million) and lower outside services ($9.4 million), offset by higher compensation expense ($1.1 million) and system product losses ($2.5 million).

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

The $16.1 million increase in gross margin reflects higher fractionation and treating fees ($20.4 million) and higher terminaling and storage revenue ($2.6 million), offset by lower fee-based and other revenues ($6.9 million). The increase in fractionation volumes is as result of the Partnership s capacity in its fractionating facilities being at or near capacity. The Partnership is expanding its fractionation capacity at the Cedar Bayou and Gulf Coast Fractionating plants to meet increased market demand.

The $6.6 million increase in operating expenses was primarily due to higher compensation costs ($5.0 million) and higher general maintenance supplies ($3.0 million).

Marketing and Distribution

	Year Ended December 31,			Variance			
				2009 vs. 2008		2010 vs. 2009	
	2008	2009	2010	$ Change	% Change	$ Change	% Change
	($ in millions except average realized prices)						

Gross margin	$ 98.8	$ 128.9	$ 125.4	$ 30.1	30%	$ (3.5)	(3)%
Operating expenses	57.5	45.9	44.9	(11.6)	(20)%	(1.0)	(2)%
Operating margin	$ 41.3	$ 83.0	$ 80.5	$ 41.7	101%	$ (2.5)	(3)%
Operating statistics:							
Natural gas sales, BBtu/d)	417.4	510.3	634.9	92.9	22%	124.6	24%
NGL sales, MBbl/d	284.0	276.1	246.7	(7.9)	(3)%	(29.4)	(11)%
Average realized prices:							
Natural gas, $/MMBtu	$ 7.81	$ 3.65	$ 4.31	$ (4.16)	(53)%	$ 0.66	18%
NGL, $/gal	1.40	0.80	1.10	(0.60)	(43)%	0.30	38%

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Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

The $30.1 million increase in gross margin for 2009 was due to higher natural gas sales volumes of $261.8 million, lower product purchase costs of $3,312.4 million and a $33.0 million decrease in lower of cost or market adjustment, offset by lower realized commodity prices of $3,334.9 million, and lower NGL sales volumes of $188.2 million, lower fee-based and other revenues of $37.6 million and lower business interruption proceeds of $16.3 million.

Natural gas sales volumes are higher due to increased purchases for resale. NGL sales volumes are lower beginning in the third quarter of 2009 due to a change in contract terms with a petrochemical supplier that had a minimal impact to gross margin.

The $11.6 million decrease in operating expenses was primarily due to a decrease in fuel and utilities expense of $5.8 million, a decrease in maintenance and supplies expenses of $4.2 million and a decrease in outside services of $1.0 million. Factors contributing to the decrease included the expiration of a barge contract, partially offset by increased truck utilization.

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

The $3.5 million decrease in gross margin was due to increased commodity prices of $1,287.9 million and higher natural gas volumes of $166.2 million offset by lower NGL volumes of $359.8 million, lower fee-based and other revenues of $20.4 million, and increased product purchases of $1,077.2 million. Lower 2010 margins at inventory locations were primarily due to the 2009 impact of higher margins on forward sales agreements that were fixed at relatively high 2008 prices, along with spot fractionation volumes and associated fees. These items were partially offset by higher marketing fees on contract purchase volumes due to overall higher 2010 market prices. Margin on transportation activity decreased due to expiration of a barge contract partially offset by increased truck activity.

Natural gas sales volumes are higher due to increased purchases for resale. NGL sales volumes are lower due to a change in contract terms with a petrochemical supplier that had a minimal impact to gross margin.

Operating expenses were essentially flat.

Other

	Years Ended December 31,			2009 vs. 2008		2010 vs. 2009	
	2008	2009	2010	Change	% Change	Change	% Change
				($ in millions)			
Gross margin	$ (33.6)	$ 46.3	$ 4.0	$ 79.9	238%	$ (42.3)	(91)%
Operating margin	$ (33.6)	$ 46.3	$ 4.0	$ 79.9	238%	$ (42.3)	(91)%

Other contains the financial effects of the cash flow hedging program on profitability. The primary purpose of the Partnership s commodity risk management activities is to hedge its exposure to commodity price risk and reduce fluctuations in our operating cash flow despite fluctuations in commodity prices. The Partnership has hedged the commodity price associated with a portion of its expected natural gas, NGL and condensate equity volumes by entering into derivative financial instruments. The Partnership s hedging strategy is in effect to forward sell its equity gas and NGL volumes generated by our gas plants. As such, these hedge positions will enhance the Partnership s margins in periods of falling prices and decrease its margins in periods of rising prices.

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

Our cash flow hedges increased gross margin by $79.9 million during 2009 versus 2008, as lower commodity prices yielded higher settlement revenues on derivative contracts.

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Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

Our cash flow hedging program decreased gross margin by $42.3 million during 2010 versus 2009, due to higher commodity prices which resulted in lower revenues from settlements on derivative contracts, as well as the impact of lower volumes hedged.

Insurance Update

Hurricanes Katrina and Rita affected certain of our Gulf Coast facilities in 2005. The final purchase price allocation for our acquisition from Dynegy in October 2005 included an $81.1 million receivable for insurance claims related to property damage caused by Hurricanes Katrina and Rita. During 2008, our cumulative receipts exceeded such amount, and we recognized a gain of $18.5 million. During 2009, expenditures related to these hurricanes included $0.3 million capitalized as improvements. The insurance claim process is now complete with respect to Hurricanes Katrina and Rita for property damage and business interruption insurance.

Certain of our Louisiana and Texas facilities sustained damage and had disruptions to their operations during the 2008 hurricane season from two Gulf Coast hurricanes Gustav and Ike. As of December 31, 2008, we recorded a $19.3 million loss provision (net of estimated insurance reimbursements) related to the hurricanes. During 2010 and 2009, the estimate was reduced by $3.3 million and $3.7 million. During 2009, expenditures related to the hurricanes included $33.7 million for previously accrued repair costs and $7.5 million capitalized as improvements.

Liquidity and Capital Resources

As a result of our conveyances of all of our remaining operating assets to the Partnership, 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 shareholders, 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 Risk Factors. As of March 31, 2011, 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
- 11,645,659 of the 84,756,009 outstanding common units of the Partnership, representing 13.7% of the limited partnership interest.

Our ownership of the general partner interest entitles us to receive:

- 2% of all cash distributed in a quarter.

Our ownership in respect to the IDR s of the Partnership that we hold 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.

The General Partner s Board of Directors increased the fourth quarter 2010 distribution by $0.01 per common unit, or $0.04 on an annualized basis. Based on the $2.19 annualized rate, a quarterly distribution by the Partnership of $0.5475 per common unit will result in quarterly distributions to us of $6.4 million, or

$25.5 million on an annualized basis, in respect of our common units in the Partnership. Such distribution would also result in quarterly distributions to us in respect of our 2% general partner interest and the IDRs of $7.1 million, or $28.4 million on an annualized basis.

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. On February 21, 2011, based on the pro rata dividend declared for the portion of the fourth quarter of 2010 following our IPO of $0.0616 per share of our common stock, we paid an equivalent initial quarterly dividend of $0.2575 per share of our common stock, or $1.03 per share on an annualized basis. The total dividend paid was $2.6 million.

As of December 31, 2010, we had $188.4 million of cash on hand, including $76.3 million of cash belonging to the Partnership. We do not have access to the Partnership s cash as it is restricted for the use of the Partnership. We have the ability to use $112.1 million of the cash on hand and available to us to satisfy our aggregate tax liability of approximately $88.0 million over the next fourteen years associated with our sales of assets to the Partnership and related financings as well as to fund the reimbursement of certain capital expenditures to the Partnership associated with its acquisition of Versado. In addition, we have a contingent obligation to contribute to the Partnership limited distribution support in any quarter through 2011 if and to the extent the Partnership has insufficient available cash to fund a distribution of $0.5175 per unit, limited to $8.0 million per quarter. We have yet and do not currently expect to make any payments pursuant to this distribution support obligation.

Our and the Partnership s cash generated from operations has been sufficient to finance operating expenditures and non-acquisition related capital expenditures. Based on our anticipated levels of operations and absent any disruptive events, we believe that internally generated cash flow, primarily from distributions received from the Partnership and borrowings available under our senior secured credit facility should provide sufficient resources to finance our operations, non-acquisition related capital expenditures, long-term indebtedness obligations and collateral requirements.

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 shareholders from available cash. On February 14, 2011, the Partnership paid its quarterly distribution of $0.5475 per common unit per quarter (or $2.19 per common unit on an annualized basis) for the quarter ended December 31, 2010. Based on the Partnership s current capital structure, the distribution of $0.5475 per common unit resulted in a quarterly distribution to us of $13.5 million in respect of our Partnership interests.

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 Risk Factors for more information about the risks that may impact your investment in us.

A significant portion of the Partnership s capital resources are utilized in the form of cash and letters of credit to satisfy counterparty collateral demands. These counterparty collateral demands reflect our non-investment grade status, as assigned to us and the Partnership by Moody s Investors Service, Inc. and Standard & Poor s Ratings Service, and counterparties views of our financial condition and ability to satisfy our performance obligations, as well as commodity prices and other factors. At February 14, 2011, we had no total outstanding letter of credit postings and the Partnership had $111.8 million.

Working Capital. Working capital is the amount by which current assets exceed current liabilities. The Partnership s working capital requirements are primarily driven by changes in accounts receivable and accounts payable. These changes are impacted by changes in the prices of commodities that the Partnership buys and sells. In general, the Partnership s working capital requirements increase in periods of rising commodity prices and decrease in periods of declining commodity prices. However, the Partnership s working capital needs do not necessarily change at the same rate as commodity prices because both accounts receivable and accounts payable are impacted by the same commodity prices. In addition, the timing of payments received by the Partnership s customers or paid to their suppliers can also cause fluctuations in working capital because the Partnership settles with most of their larger suppliers and customers on a monthly basis and often near the end of the month. The Partnership expects that their future working capital requirements will be impacted by these same factors. The Partnership s cash flows provided by operating activities will be sufficient to meet their operating requirements for the next twelve months.

Subsequent Events. On January 24, 2011, the Partnership completed a public offering of 8,000,000 common units under an existing shelf registration statement on Form S-3 at a price of $33.67 per common unit ($32.41 per common unit, net of underwriting discounts), providing net proceeds of $259.3 million. Pursuant to the exercise of the underwriters overallotment option, on February 3, 2011 the Partnership sold an additional 1,200,000 common units, providing net proceeds of $38.9 million. In addition, we contributed $6.3 million for 187,755 general partner units to maintain our 2% general partner interest in the Partnership. The Partnership used the net proceeds from the offering to reduce borrowings under its senior secured credit facility.

On February 2, 2011, the Partnership privately placed $325.0 million in aggregate principal amount of 67/8% Senior Notes due 2021 (the 67/8% Notes) resulting in net proceeds of $319.3 million.

On February 4, 2011 the Partnership exchanged $158.6 million principal amount of its 67/8% Notes for $158.6 million aggregate principal amount of its 111/4% Senior Notes due 2017 (the 111/4% Notes). In conjunction with the exchange the Partnership paid a premium in cash of $28.6 million. The debt covenants related to the remaining $72.7 million of face value of the 111/4% Notes were removed as the Partnership received sufficient consents in connection with the exchange offer to amend the indenture.

Net cash from the completion of the unit offerings, the note offering and the exchange offer was used to reduce outstanding borrowings under the Partnership s senior secured credit facility by $595.2 million. Taking into account these payments, as of December 31, 2010, the Partnership s available borrowings under its senior secured credit facility would have been $828.6 million.

Cash Flow

The following table and discussion of the Operating Activities, Investing Activities, and Financing Activities summarizes the consolidated cash flows of us and the Partnership provided by or used in operating activities, investing activities and financing activities for the periods indicated:

	Year Ended December 31,		
	2008	**2009**	**2010**
		(In millions)	
Net cash provided by (used in):			
Operating activities	$ 390.7	$ 335.8	$ 208.5
Investing activities	(206.7)	(59.3)	(134.6)
Financing activities	0.9	(386.9)	(137.9)

Operating Activities

The changes in net cash provided by operating activities are attributable to our consolidated net income adjusted for non-cash charges as presented in the Consolidated Statements of Cash Flows included in our historical consolidated financial statements and related notes thereto appearing elsewhere in this

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prospectus and changes in working capital as discussed above under Liquidity and Capital Resources Working Capital. We expect our cash flows provided by operating activities will be sufficient to meet our operating requirements for the next twelve months.

For the year ended December 31, 2010 compared to 2009, net cash provided by operating activities decreased by $127.3 million primarily due to the following:

- a decrease in net income of $15.9 million;

- a decrease in non-cash risk management activities of $10.3 million due to higher average future prices on commodity valuations;

- a decrease in the change in operating assets and liabilities of $147.6 million, primarily driven by higher payable and receivable balances in 2010; and

- offset by changes in net losses related to debt repurchases and extinguishments of $13.1 million.

The $54.9 million decrease in net cash provided by operating activities in 2009 compared to 2008 was primarily due to the following:

- net cash flow from consolidated operations (excluding cash payments for interest, cash payments for income taxes and distributions received from unconsolidated affiliates) decreased $48.3 million period-to-period. The decrease in operating cash flow is generally due to a decrease in net income of $55.3 million. Please see Results of Operations Year Ended December 31, 2009 Compared to Year Ended December 31, 2008 for a discussion of material items that impacted our operating cash flow; and

- cash payments for interest expense decreased $11.8 million period-to-period primarily due to a reduction in and change in the mix of debt due to debt retirements and refinancing activities and lower effective interest rates.

Investing Activities

Net cash used in investing activities increased by $75.3 million for the year ended December 31, 2010 compared to the year ended 2009, primarily due to increased capital spending of $39.9 million offset by a decrease in proceeds from property insurance claims of $35.3 million received in 2009.

Net cash used in investing activities decreased by $147.4 million to $59.3 million for 2009 compared to $206.7 million for 2008. The decrease is attributable to lower capital expenditures in 2009 and the VESCO acquisition in 2008.

The following table lists gross additions to property, plant and equipment, cash flows used in property, plant and equipment additions and the difference, which is primarily settled accruals and non-cash additions:

	Year Ended December 31,		
	2008	**2009**	**2010**
		(In millions)	
Gross additions to property, plant and equipment	$ 147.1	$ 101.9	$ 147.2

Inventory line-fill transferred to property, plant and equipment	(5.8)	(9.8)	(0.4)
Change in accruals and other	(9.0)	6.6	(7.5)
Purchase price adjustment related to consolidation of VESCO		0.7	
Cash expenditures	$ 132.3	$ 99.4	$ 139.3

Financing Activities

Net cash used in financing activities for the year ended 2010 compared to 2009 decreased by $249 million. The decrease was primarily due to a $457.6 million dividend to our Series B Preferred, common

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stockholders and common equivalents, partially offset by a net decrease in repayments on indebtedness of $322.9 million and proceeds from the sale of limited partner interests in the Partnership of $542.5 million.

Net cash used in financing activities in 2009 was primarily due to net repayments on indebtedness and distributions by the Partnership, partially offset by equity issuances.

Net cash provided by financing activities during 2008 was primarily due to net borrowings, net of repayments on indebtedness and repurchases, partially offset by increased dividends paid to stockholders in 2008.

Capital Requirements

The midstream energy business can be capital intensive, requiring significant investment to maintain and upgrade existing operations. A significant portion of the cost of constructing new gathering lines to connect to the Partnership s gathering system is generally paid for by the natural gas producer. However, the Partnership expects to make significant expenditures during the next year for the construction of additional natural gas gathering and processing infrastructure and to enhance the value of its logistics and marketing assets.

The Partnership categorizes its capital expenditures as either: (i) maintenance expenditures or (ii) expansion expenditures. Maintenance expenditures are those expenditures that are necessary to maintain the service capability of its existing assets including the replacement of system components and equipment which is worn, obsolete or completing its useful life, the addition of new sources of natural gas supply to its systems to replace natural gas production declines and expenditures to remain in compliance with environmental laws and regulations. Expansion 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.

	Year Ended December 31,		
	2008	**2009**	**2010**
		(In millions)	
Capital expenditures			
Expansion	$ 74.5	$ 55.4	$ 93.9
Maintenance	72.6	46.5	53.3
	$ 147.1	$ 101.9	$ 147.2

The Partnership estimates that its capital expenditures for 2011 will be approximately $230 million, which does not include acquisitions, and of which approximately 25% will be spent on maintenance. Management is considering a number of expansion projects which could significantly increase this amount.

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Credit Facilities and Long-Term Debt

The following table summarizes our and the Partnership s debt as of December 31, 2010 (in millions):

Our Obligations:	
Holdco Loan, due February 2015	$ 89.3
TRI Senior secured revolving credit facility due July 2014	
Obligations of the Partnership:	
Senior secured revolving credit facility, due July 2015	765.3
Senior unsecured notes, 81/4% fixed rate, due July 2016	209.1
Senior unsecured notes, 111/4% fixed rate, due July 2017	231.3
Unamortized discounts, net of premiums	(10.3)
Senior unsecured notes, 77/8% fixed rate, due July 2018	250.0
Total debt	1,534.7
Current maturities of debt	
Total long-term debt	$ 1,534.7

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. We have retired all amounts outstanding under our senior secured term loan facility due July 2016 as of December 2010. Our debt obligations, including those of TRI, do not restrict the ability of the Partnership to make distributions to us. TRI s senior secured credit facility has restrictions and covenants that may limit our ability to pay dividends to our stockholders. Please read TRI Senior Secured Credit Facility for a discussion of the restrictions and covenants in TRI s senior secured credit facility.

As of December 31, 2010, both we and the Partnership were in compliance with the covenants contained in our various debt agreements.

Holdco Loan

On August 9, 2007, we borrowed $450 million under this facility. Interest on borrowings under the facility are payable, at our option, either (i) entirely in cash, (ii) entirely by increasing the principal amount of the outstanding borrowings or (iii) 50% in cash and 50% by increasing the principal amount of the outstanding borrowings.

We are the borrower under this facility. We have pledged TRI stock as collateral under this loan agreement.

On November 3, 2010, we amended our Holdco Loan to name our wholly-owned subsidiary, TRI, as guarantor to our obligations under the credit agreement. The operations and assets of the Partnership continue to be excluded as guarantors of the Holdco Loan. In conjunction with the guaranty agreement, the applicable margin for borrowings under the facility was reduced from 5.0% to 3.75%. At our option, should we choose to pay the interest on this loan in cash versus increasing the principal amount of the outstanding borrowings, the applicable margin for borrowings would be further reduced to 3.0%.

TRI Senior Secured Credit Facility

On January 5, 2010, we entered into a senior secured credit facility providing senior secured financing of $600 million, consisting of:

- $500 million senior secured term loan facility (fully repaid as of December 2010); and

- $100 million senior secured revolving credit facility (reduced to $75 million and undrawn as of December 2010).

The entire amount of our credit facility is available for letters of credit and includes a limited borrowing capacity for borrowings on same-day notice referred to as swing line loans. Our available capacity under this facility is currently $75 million. TRI is the borrower under this facility.

Borrowings under the credit agreement bear interest at a rate equal to an applicable margin, plus at our option, either (a) a base rate determined by reference to the higher of (1) the prime rate of Deutsche Bank, (2) the federal funds rate plus 0.5%, and (3) solely in the case of term loans, 3%, or (b) LIBOR as determined by reference to the higher of (1) the British Bankers Association LIBOR Rate and (2) solely in the case of term loans, 2%.

Principal amounts outstanding under our senior secured revolving credit facility are due and payable in full on July 5, 2014. During 2010, we used the proceeds from our sales of the Permian Business and Straddle Assets, Versado and VESCO, as well as the secondary public offering of 8,500,000 common units of the Partnership that we owned to fully repay the outstanding balance on the senior secured term loan.

The credit agreement is secured by a pledge of our ownership in our restricted subsidiaries and contains a number of covenants that, among other things, restrict, subject to certain exceptions, our ability to incur additional indebtedness (including guarantees and hedging obligations); create liens on assets; enter into sale and leaseback transactions; engage in mergers or consolidations; sell assets; pay dividends and make distributions or repurchase capital stock and other equity interests; make investments, loans or advances; make capital expenditures; repay, redeem or repurchase certain indebtedness; make certain acquisitions; engage in certain transactions with affiliates; amend certain debt and other material agreements; and change our lines of business.

Senior Secured Revolving Credit Facility of the Partnership due 2015

On July 19, 2010, the Partnership entered into an amended and restated five-year $1.1 billion senior secured credit facility, which allows it to request increases in commitments up to an additional $300 million.

The amended and restated senior secured credit facility replaces the Partnership s former $977.5 million senior secured revolving credit facility due February 2012.

For the year ended December 31, 2010, the Partnership had gross borrowings under its senior secured revolving credit facilities of $1,343.1 million, and repayments totaling $1,057.0 million, for a net increase for the year ended December 31, 2010 of $286.1 million.

The amended and restated credit facility bears interest at LIBOR plus an applicable margin ranging from 2.25% to 3.5% (or base rate at the borrower s option) dependent on the Partnership s consolidated funded indebtedness to consolidated adjusted EBITDA ratio. The Partnership s amended and restated senior secured credit facility is secured by a majority of the Partnership s assets.

The Partnership s senior secured credit facility restricts its ability to make distributions of available cash to unitholders if a default or an event of default (as defined in our senior secured credit agreement) has occurred and is continuing. The senior secured credit facility requires the Partnership to maintain a consolidated funded indebtedness to consolidated adjusted EBITDA of less than or equal to 5.50 to 1.00. The senior secured credit facility also requires the Partnership to maintain an interest coverage ratio (the ratio of our consolidated EBITDA to our consolidated interest expense, as defined in the senior secured credit agreement) of greater than or equal to 2.25 to 1.00 determined as of the last day of each quarter for the four-fiscal quarter period ending on the date of determination, as well as upon the occurrence of certain events, including the incurrence of additional permitted indebtedness.

The Partnership s Outstanding Notes

On June 18, 2008, the Partnership privately placed $250 million in aggregate principal amount at par value of 81/4% senior notes due 2016 (the 81/4% Notes). On July 6, 2009, the Partnership privately placed $250 million in aggregate principal amount of the 111/4% Notes. The 111/4% Notes were issued at 94.973% of

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the face amount, resulting in gross proceeds of $237.4 million. See Liquidity and Capital Resources Subsequent Events for a discussion of the Partnership s exchange of its 67/8% Notes for 111/4% Notes.

On August 13, 2010, the Partnership privately placed $250 million in aggregate principal amount of its 77/8% senior notes due 2018. These notes are unsecured senior obligations that rank *pari passu* in right of payment with existing and future senior indebtedness of the Partnership, including indebtedness under its credit facility. They are senior in right of payment to any of the Partnership s future subordinated indebtedness.

The Partnership s senior unsecured notes and associated indenture agreements (other than the indenture for the 111/4 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.

Off-Balance Sheet Arrangements

We currently have no off-balance sheet arrangements as defined by the SEC. See Contractual Obligations below and Commitments and Contingencies included under Note 16 to our Audited Consolidated Financial Statements beginning on page F-1 of this Prospectus for a discussion of our commitments and contingencies, some of which are not recognized in the consolidated balance sheets under GAAP.

Contractual Obligations

Following is a summary of our contractual cash obligations over the next several fiscal years, as of December 31, 2010:

	Payments Due By Period				
Contractual Obligations	**Total**	**Less Than 1 Year**	**1-3 Years**	**4-5 Years**	**More Than 5 Years**
			(In millions)		
Debt obligations[1]	$ 1,534.7	$	$	$ 854.6	$ 680.1
Interest on debt obligations[2]	427.8	67.7	189.7	118.8	51.6
Operating lease and service contract obligations[3]	52.0	13.1	16.5	9.7	12.7
Capacity and terminaling payments[4]	12.9	6.6	6.3		
Land site lease and right-of-way[5]	20.4	1.3	2.4	2.1	14.6
Asset retirement obligation	37.5				37.5
Commodities[6]	98.1	98.1			
Purchase order commitments[7]	63.5	63.0	0.5		
	$ 2,246.9	$ 249.8	$ 215.4	$ 985.2	$ 796.5

Commodities Purchase Commitments		
Natural Gas (millions MMBtu)	9.3	9.3
NGL (millions of gallons)	56.3	56.3

(1) Represents our scheduled future maturities of consolidated debt obligations for the periods indicated. See Debt Obligations included under Note 9 to our Consolidated Financial Statements beginning on page F-1 of this prospectus for information regarding our debt obligations.

(2) Represents interest expense on our debt obligations based on interest rates as of December 31, 2010 and the scheduled future maturities of those debt obligations.

(3) Includes minimum payments on lease obligations, service contracts, right-of-way agreement, with site leases and railcar leases.

(4) Consists of capacity payments for firm transportation contracts.

(5) Lease site and right-of-way expenses provide for surface and underground access for gathering, processing and distribution assets that are located on property not owned by us; these agreements expire at various dates through 2099.

(6) Includes natural gas and NGL purchase commitments.

(7) Consists of open purchase orders and Versado remediation projects.

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, 2010, the net book value of our property, plant and equipment was $2.5 billion and we recorded $185.5 million in depreciation expense for the year ended December 31, 2010. The weighted average life of our long-lived assets is approximately 20 years. 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 $20.6 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 $25.1 million in the year of the impairment. There have been no material changes impacting estimated useful lives of the assets

Revenue Recognition. As of December 31, 2010, our balance sheet reflects total accounts receivable from third parties of $466.6 million. We have recorded an allowance for doubtful accounts as of December 31, 2010 of $7.9 million.

Our exposure to uncollectible accounts receivable relates to the financial health of its counterparties. We have an active credit management process which is focused on controlling loss exposure to bankruptcies or other liquidity issues of counterparties. If an assessment of uncollectible accounts resulted in a 1% reduction of our third -party accounts receivable, our annual operating income would decrease by $4.7 million in the year of the assessment.

Price Risk Management (Hedging). Our net income and cash flows are subject to volatility stemming from changes in commodity prices and interest rates. To reduce the volatility of our cash flows, the Partnership has entered into (i) derivative financial instruments related to a portion of its equity volumes to manage the purchase and sales prices of commodities and (ii) interest rate financial instruments to fix the interest rate on the Partnership s variable debt. 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 our 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.

Recent Accounting Pronouncements

For a discussion of recent accounting pronouncements that will affect us, see Significant Accounting Policies included under Note 4 to our Audited Consolidated Financial Statements beginning on page F-1 of this Prospectus.

Quantitative and Qualitative Disclosures about Market Risk

The Partnership s principal market risks are its exposure to changes in commodity prices, particularly to the prices of natural gas and NGLs, changes in interest rates, as well as nonperformance by our customers. The Partnership does not use risk sensitive instruments for trading purposes.

Commodity Price Risk. A majority 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 our control. We monitor these risks and enter into hedging transactions designed to mitigate the impact of commodity price fluctuations on our business. Cash flows from a derivative instrument designated as a hedge are classified in the same category as the cash flows from the item being hedged.

The primary purpose of 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, 2010, the Partnership has hedged the commodity price associated with a portion of its expected natural gas, NGL and condensate equity volumes that result from its percent of proceeds processing arrangements in Field Gathering and Processing, and the LOU portion of the Coastal Gathering and Processing Operations through 2014 by entering into derivative financial instruments including swaps and purchased puts (or floors). The percentages of expected equity volumes that are hedged decrease over time. With swaps, the Partnership typically receive 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 our actual equity volumes, the Partnership typically limits its use of swaps to hedge the prices of less than its expected natural gas and NGL equity volumes. The Partnership utilizes purchased puts (or floors) to hedge additional expected equity commodity volumes without creating volumetric risk. The Partnership intends to continue to manage its exposure to commodity prices in the future by entering into similar hedge transactions using swaps, collars, purchased puts (or floors) or other hedge 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 our expected equity NGL composition. We believe this strategy avoids uncorrelated risks resulting from employing hedges on crude oil or other petroleum products as proxy hedges of NGL prices. The NGL hedges fair values are based on published index prices for delivery at Mont Belvieu through 2013, except for the price of isobutane in 2012, which is based on the ending 2011 pricing. The natural gas hedges fair values are based on published index prices for delivery at WAHA, Permian Basin and Mid-Continent, which closely approximate the actual NGL and natural gas 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. 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 the 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.

For all periods presented we entered into hedging arrangements for a portion of our forecasted equity volumes. Floor volumes and floor pricing are based solely on purchased puts (or floors). During 2008, 2009 and 2010, our operating revenues were increased (decreased) by net hedge adjustments of $(65.1) million, $69.7 million and $8.4 million.

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As of December 31, 2010, our commodity derivative arrangements were as follows:

Natural Gas

Instrument Type	Index	Price $/MMBtu	MMBtu per day 2011	2012	2013	Fair Value *(In millions)*
Swap	IF-WAHA	6.29	23,750			$ 16.9
Swap	IF- WAHA	6.61		14,850		9.6
Swap	IF- WAHA	5.59			4,000	0.8
Total Swaps			23,750	14,850	4,000	
Swap	IF-PB	5.42	2,000			0.8
Swap	IF-PB	5.54		4,000		1.1
Swap	IF-PB	5.54			4,000	0.8
Total Swaps			2,000	4,000	4,000	
Swap	IF-NGPL MC	6.87	4,350			4.1
Swap	IF-NGPL MC	6.82		4,250		3.1
Total Swaps			4,350	4,250		
			30,100	23,100	8,000	
Natural Gas Basis Swaps						
Basis Swaps	Various Indexes, Maturities January 2011		May 2011			(0.4)
						$ 36.8

NGLs

Instrument Type	Index	Price $/gal	Barrels per day 2011	2012	2013	Fair Value *(In millions)*
Swap	OPIS-MB	0.85	8,550			$ (18.0)
Swap	OPIS-MB	0.85		6,700		(6.6)
Swap	OPIS-MB	0.92			3,400	(4.0)
Total Swaps			8,550	6,700	3,400	

Floor	OPIS-MB	1.44	253				0.8
Floor	OPIS-MB	1.43		294			1.3
Total Floors			253	294			
Total Sales			8,803	6,994	3,400		
						$	(26.5)

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Condensate

Instrument Type	Index	Price $/Bbl	Barrels per day 2011	2012	2013	2014	Fair Value *(In millions)*
Swap	NY-WTI	80.37	1,100				$ (5.4)
Swap	NY-WTI	82.25		950			(4.0)
Swap	NY-WTI	81.82			800		(3.1)
Swap	NY-WTI	90.03				700	(0.6)
Total Sales			1,100	950	800	700	
							$ (13.1)

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

The Partnership accounts for the fair value of our financial assets and liabilities using a three-tier fair value hierarchy, which prioritizes the significant inputs used in measuring fair value. These tiers include: Level 1, defined as observable inputs such as quoted prices in active markets; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs in which little or no market data exists, therefore required an entity to develop its own assumptions. The value of the NGL derivative contracts is determined utilizing a discounted cash flow model for swaps and a standard option pricing model for options, based on inputs that are either readily available in public markets or are quoted by counterparties to these contracts. Prior to 2009, all of the NGL contracts were classified as Level 3 within the hierarchy. In 2009, we were able to obtain inputs from quoted prices related to certain of these commodity derivatives for similar assets and liabilities in active markets. These inputs are observable for the asset or liability, either directly or indirectly, for the full term of the commodity swaps and options. For the NGL contracts that have inputs from quoted prices, the classification of these instruments changed from Level 3 to Level 2 within the fair value hierarchy. For those NGL contracts where we were unable to obtain quoted prices for the full term of the commodity swap and options, the NGL valuations are still classified as Level 3 within the fair value hierarchy.

Interest Rate Risk. We are exposed to changes in interest rates, primarily as a result of variable rate borrowings under Targa and the Partnership s senior secured revolving credit facilities. To the extent that interest rates increase, interest expense for our revolving debt will also increase. As of December 31, 2010, we have variable rate borrowings of $89.3 million and the Partnership has variable interest rate borrowings of $765.3 million. In an effort to reduce the variability of our cash flows, the Partnership has entered into several interest rate swap and interest rate basis swap agreements. Under these agreements, which are accounted for as cash flow hedges, the base interest rate on the specified notional amount of the Partnership s variable rate debt is effectively fixed for the term of each agreement and ineffectiveness is required to be measured each reporting period. The fair values of the interest rate swap agreements, which are adjusted regularly, have been aggregated by counterparty for classification in our consolidated balance sheets. Accordingly, unrealized gains and losses relating to the interest rate swaps are recorded in accumulated other comprehensive income (OCI) until the interest expense on the related debt is recognized in earnings.

A hypothetical increase of 100 basis points in the underlying interest rate, after taking into account our interest rate swaps, would increase our consolidated interest expense by $5.5 million.

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As of December 31, 2010, the Partnership had the following open interest rate swaps:

Period	Fixed Rate	Notional Amount	Fair Value (In millions)
2011	3.52%	$ 300 million	$ (7.8)
2012	3.40%	300 million	(7.5)
2013	3.39%	300 million	(4.0)
2014	3.39%	300 million	(0.8)
			$ (20.1)

Credit Risk. The Partnership is subject to risk of losses resulting from nonpayment or nonperformance by its counterparties. The credit exposure related to commodity derivative instruments is represented by the fair value of contracts with these derivative instruments being in a net asset position at the reporting date. At such times, these outstanding instruments expose us to credit loss in the event of nonperformance by the counterparties to the agreements. Should the creditworthiness of one or more of the counterparties decline, the Partnership s ability to mitigate nonperformance risk is limited to a counterparty agreeing to either a voluntary termination and subsequent cash settlement or a novation of the derivative contract to a third party. In the event of a counterparty default, the Partnership may sustain a loss and its cash receipts could be negatively impacted.

As of December 31, 2010, the Partnership had counterparty credit exposure related to commodity derivatives with affiliates of Barclays, Credit Suisse, and BP which accounted for 62%, 13% and 12%, respectively, of the Partnership s counterparty credit exposure related to commodity derivative instruments. Barclays, and Credit Suisse are major financial institutions and BP is a major oil and gas company. These entities possess investment grade credit ratings based upon minimum credit ratings assigned by Standard & Poor s Ratings Services.

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OUR INDUSTRY

Introduction

Natural gas gathering and processing and logistics and marketing are a critical part of the natural gas value chain. Natural gas gathering and processing systems create value by collecting raw natural gas from the wellhead and separating dry gas (primarily methane) from mixed NGLs which include ethane, propane, normal butane, isobutane and natural gasoline. Most natural gas produced at the wellhead contains NGLs. Natural gas produced in association with crude oil typically contains higher concentrations of NGLs than natural gas produced from gas wells. This unprocessed natural gas is generally not acceptable for transportation in the nation s interstate pipeline transmission system or for commercial use. Processing plants extract the NGLs, leaving residual dry gas that meets interstate pipeline transmission and commercial quality specifications. Furthermore, processing plants produce NGLs which, on an energy equivalent basis, usually have a greater economic value as a raw material for petrochemicals, motor gasolines or commercial use than as a residual component of the natural gas stream. In order for the mixed NGLs to become marketable to end users, they are first fractionated into NGL products, perhaps put into storage and ultimately distributed to end users. The table below illustrates the position and function of natural gas gathering and processing and logistics and marketing within the natural gas market chain.

We believe that current industry dynamics are resulting in increases in domestic drilling within the basins in which we operate and creating the need for additional natural gas and natural gas liquids infrastructure and services. Factors contributing to this include (i) a strong crude oil and NGL price environment; (ii) the continuation of oil and gas exploration and production innovation including geophysical interpretation, horizontal drilling and well completion techniques; (iii) a trend toward increased drilling in oil, condensate and NGL rich, or liquids rich reservoirs, especially resource plays;

and (iv) increasing levels of supply of mixed NGLs to our fractionation facilities coupled with strong demand from petrochemical complexes and exports which are leading to higher capacity utilization.

The following overview provides additional information relating to the operations of our assets as well an overview of the potential demand for our services and other related information. We believe our integrated midstream platform is well positioned to benefit from these industry trends and to compete for opportunities to provide new infrastructure and services.

Overview of Natural Gas Gathering and Processing

Gathering. At the initial stages of the midstream value chain, a network of typically small diameter pipelines known as gathering systems directly connect to wellheads, batteries or central delivery points (CDPs) in the production area. These gathering systems transport raw natural gas to a common location for processing and treating. A large gathering system may involve thousands of miles of gathering lines connected to thousands of wells or indirectly to wells via CDPs. Gathering systems are often designed to be flexible to allow gathering of natural gas at different pressures, perhaps flow natural gas to multiple plants, provide the ability to connect new producers quickly, and most importantly are generally scalable to allow for additional production without significant incremental capital expenditures.

Field Compression. Since individual wells produce at progressively lower field pressures as they deplete, it becomes increasingly difficult to produce the remaining production in the ground against the pressure that exists in the connecting gathering system. Natural gas compression is a mechanical process in which a volume of natural gas at a given pressure is compressed to a desired higher pressure, which allows the natural gas to flow into a higher pressure system. Field compression is typically used to allow a gathering system to operate at a lower pressure or provide sufficient discharge pressure to deliver natural gas into a higher pressure system. If field compression is not installed, then less of the remaining natural gas in the ground will be produced because it cannot overcome the gathering system pressure. In contrast, if field compression is installed, then a well can continue delivering natural gas that otherwise would not be produced.

Treating and Dehydration. After gathering, the second process in the midstream value chain is treating and dehydration. Natural gas contains various contaminants, such as water vapor, carbon dioxide and hydrogen sulfide, that can cause significant damage to intrastate and interstate pipelines and therefore render the gas unacceptable for transmission on such pipelines. In addition, end-users will not purchase natural gas with a high level of these contaminants. To meet downstream pipeline and end-user natural gas quality standards, the natural gas is dehydrated to remove the saturated water and is chemically treated to remove the carbon dioxide and hydrogen sulfide from the gas stream.

Processing. Once the contaminants are removed, the next step involves the separation of pipeline quality residue gas from mixed NGLs, a method known as processing. Most decontaminated natural gas is not suitable for long-haul pipeline transportation or commercial use and must be processed to remove the heavier hydrocarbon components. The removal and separation of hydrocarbons during processing is possible because of the differences in physical properties between the components of the raw gas stream. There are four basic types of natural gas processing methods: cryogenic expansion, lean oil absorption, straight refrigeration and dry bed absorption. Cryogenic expansion represents the latest generation and most prevalent form of processing in the U.S, incorporating extremely low temperatures and high pressures to provide the best processing and most economical extraction.

Natural gas is processed not only to remove NGLs that may interfere with pipeline transportation or the end use of the natural gas, but also to separate from the natural gas those hydrocarbon liquids that could have a higher value as NGLs than as natural gas. The principal components of residue gas are methane and to a much lower extent ethane, but processors typically have the option to recover most of the ethane from the residue gas stream for processing into NGLs or reject some of the ethane and leave it in the residue gas stream, depending on pipeline restrictions and whether the ethane is more valuable being processed or left in the natural gas stream. The residue gas is sold to industrial, commercial and residential customers and electric utilities. The premium or discount in value between natural gas and processed NGLs is known as the frac spread. Because NGLs often serve as substitutes for products derived from crude oil, NGL prices tend to move in relation to crude prices.

Natural gas processing occurs under a contractual arrangement between the producer or owner of the raw natural gas stream and the processor. There are many forms of processing contracts which vary in the amount of commodity price risk they carry. The specific commodity exposure to natural gas or NGL prices is highly dependent on the types of contracts. Processing contracts can vary in length from one month to the life of the field. Four typical processing contract types are described below:

Percent-of-Proceeds, Percent-of-Value or Percent-of-Liquids. In a percent-of-proceeds arrangement, the processor remits to the producers a percentage of the proceeds from the sales of residue gas and NGL products or a percentage of residue gas and NGL products at the tailgate of the processing facilities. In some percent-of-proceeds arrangements, the producer is paid a percentage of an index price for residue gas and NGL products, less agreed adjustments, rather than remitting a portion of the actual sales proceeds. The percent-of-value and percent-of-liquids are variations on this arrangement. These types of arrangements expose the processor to some commodity price risk as the revenues from the contracts are directly correlated with the price of natural gas and NGLs.

Keep-Whole. A keep-whole arrangement allows the processor to keep 100% of the NGLs produced and requires the return of natural gas, or value of the gas, to the producer or owner. A wellhead purchase contract is a variation of this arrangement. Since some of the gas is used during processing, the processor must compensate the producer or owner for the gas shrink entailed in processing by supplying additional gas or by paying an agreed value for the gas utilized. These arrangements have the highest commodity price exposure for the processor because the costs are dependent on the price of natural gas and the revenues are based on the price of NGLs. As a result, a processor with these types of contracts benefits when the value of the NGLs is high relative to the cost of the natural gas and is disadvantaged when the cost of the natural gas is high relative to the value of the NGLs.

Fee-Based. Under a fee-based contract, the processor receives a fee per gallon of NGLs produced or per Mcf of natural gas processed. Under a pure fee-based arrangement, a processor would have no direct commodity price risk exposure.

Hybrid. Hybrid contracts are a mix of the typical processing contracts discussed above. In periods of favorable processing economics, hybrid contracts are similar to percent-of-liquids contracts or to wellhead purchases/keep-whole contracts in some circumstances, if economically advantageous to the processor. In periods of unfavorable processing economics, hybrid contracts are similar to fee-based contracts. 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,

Overview of Logistics and Marketing

Fractionation. Fractionation is the distillation of the heterogeneous mixture of extracted NGLs into individual components for end-use sale. Fractionation is accomplished by controlling the temperature and pressure of the stream of mixed liquids in order to take advantage of the difference in boiling points of separate products. As the temperature of the stream is increased, the lightest component boils off the top of the distillation tower as a gas where it then condenses into a finished NGL product that is routed to markets or to storage. The heavier components in the mixture are routed to the next tower where the process is repeated until all components have been separated. Described below are the five basic NGL components (NGL products) and their typical uses. A typical barrel of NGLs consists of ethane, propane, normal butane, isobutane and natural gasoline.

Ethane. Ethane is used primarily as feedstock in the production of ethylene, one of the basic building blocks for a wide range of plastics and other chemical products.

Propane. Propane is used as heating fuel, engine fuel and industrial fuel, for agricultural burning and drying and as petrochemical feedstock for production of ethylene and propylene.

Normal Butane. Normal butane is principally used for motor gasoline blending and as fuel gas, either alone or in a mixture with propane, and feedstock for the manufacture of ethylene and butadiene, a key ingredient of synthetic rubber. Normal butane is also used to derive isobutane.

Isobutane. Isobutane is principally used by refiners to enhance the octane content of motor gasoline and in the production of MTBE, an additive in cleaner burning motor gasoline.

Natural Gasoline. Natural gasoline is principally used as a motor gasoline blend stock or petrochemical feedstock.

As of December 31, 2009 the United States and Ontario, Canada had approximately 2.6 MMBbl/d of existing fractionation capacity with several expansions announced and underway. Mont Belvieu, TX accounted for 28% of total U.S. fractionation capacity, making it the largest NGL complex in the US. Another 18% of the fractionation capacity is located in Louisiana. Both of these regions are located close to the large petrochemical complex which is along the Gulf Coast in Texas and Louisiana and which constitutes a major consumer of NGL products.

Total U.S. and Ontario Fractionation Capacity by Location

Region	Capacity (MBbl/d)	% of Total
Mont Belvieu, TX	737	28.4%
Other Texas & New Mexico	606	23.4%
Kansas/Oklahoma	513	19.8%
Louisiana(1)	476	18.4%
Ontario and Other US	260	10.0%
Total	2,592	

The Partnership s fractionation assets are primarily located at Mont Belvieu, TX and Lake Charles, LA with approximately 79% of gross capacity located at Mont Belvieu. Based on operatorship, the Partnership is the second largest operator of fractionation in Mont Belvieu and Louisiana combined. Additionally, the Partnership is currently starting up the approximately 78 MBbl/d of additional fractionation capacity.

Mont Belvieu and Louisiana. Combined Fractionation Capacity by Operator

Company	Capacity (MBbl/d)	% of Total
Enterprise (including Promix LLC)	564	46.5%
Targa Resources(1)	283	23.3%
ONEOK	160	13.2%

Others	206	17.0%
Total	1,213	

(1) Total Louisiana capacity and Targa Resources capacity reduced by 36 MBbl/d to reflect the Partnership s idle facility in Venice, Louisiana.

Source: Purvin and Gertz, Inc, The North American NGL Industry: Risks and Rewards in the Midstream Sector: 2010 Edition and company filings.

Transportation and Storage. Once the mixed NGLs are fractionated into individual NGL products, the NGL products are stored, transported and marketed to end-use markets. The NGL industry has thousands of miles of intrastate and interstate transmission pipelines and a network of barges, rails, trucks, terminals and underground storage facilities to deliver NGLs to market. The bulk of the NGL storage capacity is located near the refining and petrochemical complexes of the Texas and Louisiana Gulf Coasts, with a second major concentration in central Kansas. Each NGL product system typically has storage capacity located both throughout the pipeline network and at major market centers to help temper seasonal demand and daily supply-demand shifts.

Barriers to Entry. Although competition within the logistics and marketing industry is robust, we believe there are significant barriers to entry for these business lines. These barriers include (i) significant costs and execution risk to construct new facilities; (ii) a finite number of sites such as ours that are connected to market hubs, pipeline infrastructure, underground storage, import / export facilities and end users and (iii) specialized expertise required to operate logistics and marketing facilities.

Industry Trends

Natural gas is a critical component of energy consumption in the U.S., accounting for approximately 24% of all energy used in 2008, representing approximately 23.8 Tcf of natural gas, according to the U.S. Energy Information Administration (EIA). Over the next 27 years, the EIA estimates that total domestic energy consumption will increase by over 15%, with natural gas consumption directly benefiting from population growth, growth in cleaner-burning natural gas-fired electric generation and natural gas vehicles, and indirectly through additions of electric vehicles. Additionally, we believe that there are numerous other trends in the industry relating to natural gas and NGLs that will continue to benefit us. These trends include the following:

Commodity Price Environment. Current crude, condensate and NGL pricing are relatively attractive compared to historical levels while current natural gas pricing is relatively less attractive. Furthermore, the existing differential between NGL prices (often linked to crude oil prices) and natural gas prices creates a premium value for the mixed NGLs relative to the value of natural gas from which they are removed. This environment incents producers to develop hydrocarbon reserves that contain oil, condensate and NGLs and incents producers or processors to remove the maximum amount of NGLs from the raw natural gas through processing.

Advances in Exploration and Production Techniques. Improvements in exploration and production capabilities including geophysical interpretation, horizontal drilling, and well completions have played a significant role in the increase of domestic shale natural gas production. The natural gas shale formations represent prolific sources of domestic hydrocarbons. With the advances in exploration and production capabilities driving finding and development costs down, natural gas produced from the shale formations is expected to represent an increasing portion of total domestic supply. As drilling activity continues to increase in these areas, gathering and pipeline systems will be required to transport the natural gas, processing plants will be needed to process such natural gas, fractionation will be required to turn mixed NGLs into commercial NGL products, and other logistics, marketing and distribution infrastructure will be utilized to distribute NGL products to the ultimate end users. We believe that improvements in geosciences, drilling technology, and completion techniques are also being used to develop and exploit other resource plays in conventional basins, including the Wolfberry and other geographic strata in the Permian Basin.

Shift to Oil and Liquids Rich Natural Gas Production. Due to the current commodity price environment, producer economics shift drilling activity toward oil production and gas production with higher levels of condensate and NGLs. As a result, the level of well permitting in liquids rich plays has been significantly increasing. Processing is generally required to strip out the mixed NGLs prior to transportation of the natural gas to end users, especially in oil and liquids rich natural gas production areas. The increased production of natural gas rich in NGLs has resulted in increased need for processing facilities and has created a significant supply of mixed NGLs that ultimately must be fractionated.

Increasing Levels of Mixed NGL Supplies and Demand for NGL Products. Due to the producers economic focus on oil, condensate and NGL rich production streams, the supply of mixed NGLs to the Gulf Coast is quickly increasing. This increase in supply has resulted in high utilization rates for fractionation services. The increased demand for fractionation has allowed many suppliers of fractionation services to increase fees and enter into longer dated contracts. Additionally, we believe that strong processing economics as a result of recent historical and forecast commodity prices are driving incremental improvements in processing recoveries which along with lighter processable NGL barrels in certain shale plays are resulting in the recovery of more ethane. In response to recent ethane and propane pricing as a petrochemical feedstock relative to competing crude-based feedstocks, Gulf Coast flexi-crackers have been shifting to lighter feedstock and are converting heavy crackers to be switchable to lighter feedstock. This increases demand for NGL products.

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OUR BUSINESS

Overview

We own general and limited partner interests, including IDRs, in Targa Resources Partners LP (NYSE: NGLS), a publicly traded Delaware limited partnership 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, storing, fractionating, treating, transporting and selling natural gas liquids, or NGLs, and NGL products and storing and terminaling refined petroleum products and crude oil.

On December 20, 2010, we completed our initial public offering, or IPO, of our common stock. We did not receive any proceeds from the sale of shares by the selling stockholders.

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. We also may enter into other economic transactions intended to increase our ability to make cash available for dividends over time. In addition, we may acquire assets that could be candidates for acquisition by the Partnership, potentially after operational or commercial improvement or further development.

As of March 31, 2011, 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
- 11,645,659 of the 84,756,009 outstanding common units of the Partnership, representing 13.7% of the limited partnership interest in the Partnership.

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 Partnership s general partner interest entitles us to receive:

- 2% of all cash distributed in respect for that quarter;

Our ownership in respect to the IDR s of the Partnership that we hold, 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.

On February 14, 2011, the Partnership paid a quarterly cash distribution of $0.5475 per common unit, or $2.19 per common unit on an annualized basis, for the fourth quarter of 2010. Such distribution resulted in a quarterly distribution to us of $7.1 million or $28.2 million on an annualized basis, in respect of our 2% general partner interest and IDRs, and $6.4 million, or $25.5 million on an annualized basis, in respect of our common units in the Partnership, for total quarterly distributions of $13.5 million, or $53.7 million on an annualized basis.

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On February 21, 2011, we paid a cash dividend of $0.0616 per share of common stock, or $2.6 million in total, to holders of our outstanding common stock. The dividend was prorated to give effect to a partial quarter following our IPO and corresponds to a full dividend of $0.2575 per share on a quarterly basis, or $1.03 per share on an annualized basis.

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. See Our Dividend Policy.

The following graph shows the historical cash distributions declared by the Partnership for the periods shown to its limited partners (including us), to us based on our 2% general partner interest in the Partnership and to us based on the IDRs. The increases in historical cash distributions to both the limited partners and the general partner since the second quarter ended June 30, 2007, as reflected in the graph set forth below, generally resulted from increases in the Partnership s per unit quarterly distribution over time and the issuance of approximately 53.9 million additional common units by the Partnership over time to finance acquisitions and capital improvements. Over the same period, the quarterly distributions declared by the Partnership in respect of our 2% general partner interest and IDRs increased approximately 3,200% from $0.2 million to $7.1 million.

Quarterly Cash Distributions by the Partnership

The graph set forth below shows hypothetical cash distributions payable to us in respect of our interests in the Partnership across an illustrative range of annualized distributions per common unit. This information is based upon the following:

(i) the Partnership has a total of 84,756,009 common units outstanding; and

(ii) we own (i) a 2% general partner interest in the Partnership, (ii) the IDRs and (iii) 11,645,659 common units of the Partnership.

The graph below also illustrates the impact on us of the Partnership raising or lowering its per common unit distribution from the 2010 fourth quarter quarterly distribution of $0.5475 per common unit, or $2.19 per common unit on an annualized basis. This information is presented for illustrative purposes only; it is not intended to be a prediction of future performance and does not attempt to illustrate the impact that changes in our or the Partnership s business, including changes that may result from changes in interest rates, energy prices or general economic conditions, or the impact that any future acquisitions or expansion projects, divestitures or issuances of additional debt or equity securities will have on our or the Partnership s results of operations.

Hypothetical Annualized Pre-Tax Partnership Distributions to Us

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.

Legal Proceedings

We are involved in various legal proceedings arising in the ordinary course of our business. See Business of Targa Resources Partners LP Legal Proceedings.

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BUSINESS OF TARGA RESOURCES PARTNERS LP

Overview

The Partnership is a leading provider of midstream natural gas and NGL services in the United States that we formed on October 26, 2006 to own, operate, acquire and develop a diversified portfolio of complementary midstream energy assets. The Partnership is engaged in the business of gathering, compressing, treating, processing and selling natural gas, storing, fractionating, treating, transporting and selling NGLs and NGL products and storing and terminaling refined petroleum products and crude oil. The Partnership operates in two primary divisions: (i) Natural Gas 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.

The Natural Gas Gathering and Processing division includes assets used in the gathering of natural gas produced from oil and gas wells and processing this gathered raw natural gas into merchantable natural gas by removing impurities and extracting a stream of combined NGLs or mixed NGLs (sometimes called Y-grade or raw mix). The Field Gathering and Processing segment assets are located in North Texas and in the Permian Basin of Texas and New Mexico. The Coastal Gathering and Processing segment assets are located in the onshore and near offshore regions of the Louisiana Gulf Coast accessing onshore and offshore gas supplies.

The Logistics and Marketing division is also referred to as the Downstream Business. It includes the activities necessary to fractionate mixed NGLs into finished NGL products ethane, propane, normal butane, isobutane and natural gasoline and provides certain value added services, such as the storage, terminaling, transportation, distribution and marketing of NGLs. The assets in this segment are generally connected indirectly to and supplied, in part, by the Partnership s gathering and processing segments and are predominantly located in Mont Belvieu, Texas and Southwestern Louisiana. The Marketing and Distribution segment covers all activities required to distribute and market mixed NGLs and NGL products. It includes (1) marketing and purchasing NGLs in selected United States markets; (2) marketing and supplying NGLs for refinery customers; and (3) transporting, storing and selling propane and providing related propane logistics services to multi-state retailers, independent retailers and other end users.

Since the beginning of 2007, the Partnership has completed six acquisitions from us with an aggregate purchase price of approximately $3.1 billion. The acquisitions from us are as follows:

In February 2007, in connection with its initial public offering, the Partnership acquired approximately 3,950 miles of integrated gathering pipelines that gather and compress natural gas received from receipt points in the Fort Worth Basin/Bend Arch in North Texas, two natural gas processing plants and a fractionator. These assets, together with the business conducted thereby, are collectively referred to as the North Texas System.

In October 2007, the Partnership acquired natural gas gathering, processing and treating assets in the Permian Basin of West Texas and in Southwest Louisiana. The West Texas assets, together with the business conducted thereby, are collectively referred to as SAOU and the Southwest Louisiana assets, together with the business conducted thereby, are 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. These assets, together with the businesses conducted thereby, are collectively referred to as the Logistics and Marketing division or the Downstream Business.

In April 2010, the Partnership acquired a natural gas straddle business consisting of the business and operations involving the Barracuda, Lowry and Stingray plants, including the Pelican,

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Seahawk and Cameron gas gathering pipeline systems, and the interests in the business and operations of the Bluewater, Sea Robin, Calumet, N. Terrebonne, Toca and Yscloskey plants. The Partnership also acquired certain natural gas gathering and processing systems, processing plants and related assets including the Sand Hills processing plant and gathering system, Monahans gathering system, Puckett gathering system, a 40% ownership interest in the West Seminole gathering system and a compressor overhaul facility. These assets, together with the business conducted thereby, are collectively referred to as the Permian Business.

In August 2010, the Partnership acquired a 63% ownership interest in Versado Gas Processors, L.L.C., which conducts a natural gas gathering and processing business in New Mexico consisting of the business and operations involving the Eunice, Monument and Saunders gathering and processing systems, processing plants and related assets. These assets, together with the business conducted thereby, are collectively referred to as Versado.

In September 2010, the Partnership acquired from us our 77% ownership interest in VESCO, a joint venture in which Enterprise Gas Processing, LLC and ONEOK VESCO Holdings, L.L.C. own the remaining ownership interests. VESCO owns and operates a natural gas gathering and processing business in Louisiana consisting of a coastal straddle plant and the business and operations of Venice Gathering System, L.L.C., a wholly owned subsidiary of VESCO that owns and operates an offshore gathering system and related assets (collectively, VESCO).

In March 2011, the Partnership acquired a refined petroleum products and crude oil storage and terminaling facility in Channelview, TX (the Terminal). Located on Carpenter s Bayou along the Houston Ship Channel, the Terminal can handle multiple grades of blend stocks, products and crude. The approximately $30 million purchase price was paid entirely with cash funded through borrowings under the Partnership s senior secured revolving credit facility. The Partnership expects that the transaction will be immediately accretive to its unitholders and is complementary to its existing terminal asset base and business along the Gulf Coast. The Terminal has approximately 544,000 barrels of storage capacity and contains blending and heating capabilities, tanker truck and barge loading and unloading infrastructure. Currently, the capacity is 100% leased to customers that include a multi-national oil company and regional refineries. This acquisition enables the Partnership to apply its current terminaling expertise to an expanded product slate on a long term fee basis and enhances the Partnership s cash flow mix and geographical footprint. The Partnership expects to invest incremental growth capital in the near future to expand the capacity of the Terminal.

In addition, 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, some of which occurred before the Partnership acquired its various businesses from us, have involved growth capital expenditures of approximately $313 million since 2005 and include:

Low sulfur natural gasoline project: In July 2007, the Partnership completed construction of a natural gasoline hydrotreater (the LSNG Facility) 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 MBbls/d and is supported by fee-based contracts with Marathon Petroleum Company LLC and Koch Supply and Trading LP that have certain guaranteed volume commitments or provisions for deficiency payments. The Partnership made capital expenditures of $39.5 million to convert idle equipment at Mont Belvieu into the LSNG Facility.

Operations Improvement and Efficiency Enhancement: The Partnership has historically focused on ways to improve margins and reduce operating expenses by improving its operations. Examples include energy saving initiatives such as building cogeneration capacity to self-generate electricity for the Partnership s facilities at Mont Belvieu, installing electric compression in North Texas and Versado to reduce fuel costs, emissions and operating costs, and bringing compression overhaul in-house to improve quality, turnaround time and costs.

Opportunistic Commercial Development Activities: The Partnership has used the extensive footprint of its asset base to identify and pursue projects that generate strong returns on invested capital. Examples include installing a new interconnect pipeline to the Kinder Morgan Rancho line at SAOU, developing the Winona wholesale propane terminal in Arizona, restarting the Easton Storage Facility at LOU and installing additional equipment to increase ethane recoveries at the Partnership s Lowry straddle plant.

Other Enhancements: The Partnership also has completed a number of smaller acquisitions and projects that have enhanced its existing asset base and that can provide attractive investment returns. Examples include the purchase of existing pipelines that expand beyond its existing asset base, installation of pipeline interconnects to its gathering systems and consolidation of interests in joint ventures.

The Partnership believes these projects have been successful in terms of return on investment. Because the Partnership s assets are not easily duplicated and are located in active producing areas and near key NGL markets and logistics centers, we expect that the Partnership will continue to focus on attractive investment opportunities associated with its existing asset base.

Partnership Growth Drivers

We believe the Partnership s near-term growth will be driven both by significant recently completed or pending projects as well as strong supply and demand fundamentals for its existing businesses. Over the longer-term, we expect the Partnership s growth will be driven by natural gas shale opportunities, which could lead to growth in both the Partnership s Gathering and Processing division and Downstream Business, organic growth projects and potential strategic and other acquisitions related to its existing businesses.

Organic growth projects. We expect the Partnership s near-term growth to be driven by a number of significant projects scheduled for completion in 2011 that are supported by long-term, fee-based contracts. We believe that organic growth projects, such as the ones listed below, often generate higher returns on investment than those available from third party acquisitions. Organic projects in process include:

Expansion Program at Mont Belvieu

Cedar Bayou Fractionator expansion project: The Partnership is currently starting up the approximately 78 MBbl/d of additional fractionation capacity at the Partnership s 88% owned CBF in Mont Belvieu. The capital cost is expected to be less than the original estimated gross cost of $78 million. The fractionation expansion is expected to be in service in the second quarter of 2011. This expansion is supported with 10 year fee-based contracts with ONEOK Hydrocarbons, L.P., Questar Gas Management Company and Majestic Energy Services, LLC that have certain guaranteed volume commitments or provisions for deficiency payments.

Benzene treating project: A new treater is under construction which will operate in conjunction with the Partnership s existing LSNG facility at Mont Belvieu and is designed to reduce benzene content of natural gasoline to meet new, more stringent environmental standards. The treater has an estimated gross cost of approximately $33 million and is expected to be completed and operating by the end of the year. The treater is anticipated to be in service in the fourth quarter of 2011 and is supported by a fee-based contract with Marathon Petroleum Company LLC that has certain guaranteed volume commitments or provisions for deficiency payments.

Gulf Coast Fractionators expansion project: The Partnership has announced plans by Gulf Coast Fractionators, a partnership with ConocoPhillips and Devon Energy Corporation in which the Partnership owns a 38.8% interest, to expand the capacity of its NGL fractionation facility in Mont Belvieu by 43 MBbl/d for an estimated gross cost of $75 million (our net cost is estimated to be approximately $29 million). ConocoPhillips, as the operator, will manage the expansion project.

The expansion is expected to be operational during the second quarter of 2012, subject to regulatory approvals.

SAOU Expansion Program.

The Partnership has announced a $30 million capital expenditure program to expand gathering and processing capability over the next 18 months in response to strong volume growth and new well connects associated with producer activity in the Wolfberry play as discussed below under Strong supply and demand fundamentals for the Partnership s existing businesses. This growth investment program includes new compression facilities and pipelines as well as expenditures to restart the 25 MMcf/d Conger processing plant. The Partnership expects the Conger plant to restart in April 2011. Additionally, two 15 MMcf/d processing trains from the Garden City plant are being refurbished for future use at another SAOU location.

North Texas Expansion Program.

The board of directors of the General Partner has approved approximately $40 million of capital expenditures to expand the gathering and processing capability of the Partnership s North Texas System with certain provisions of the approved expenditures subject to finalization of ongoing customer commercial agreements. The expansion program is a response to strong volume growth and new well connects associated with producer activity in oilier portions of the Barnett Shale natural gas play, especially in portions of Southern Montague and Northern Wise County as discussed below under Strong supply and demand fundamentals for the Partnership s existing businesses. The scope of the full expansion includes a major pipeline to increase residue takeaway capacity, gathering system expansions, compression equipment and other work. Certain pieces of the expansion are underway. If commercial agreements were to be consummated in the first half of 2011, we would expect most capital investment to be completed by early 2012. Management expects that additional investment will be required to keep pace with producer activity.

Additionally, the Partnership is actively pursuing other gathering and processing expansion opportunities, especially for the North Texas System, SAOU and the Sand Hills facilities. In the Downstream Business, the Partnership submitted a standard air permit application for a second CBF expansion of approximately 100 MBbl/d. Having recently passed the 45 day waiting period without regulator objection, the Partnership expects the permit registration to be received in April. With the passage of the waiting period, the Partnership has regulatory authority to proceed with the project, which it expects to do pending execution of precedent anchor commercial commitments. Furthermore, international interest in additional propane and/or butane exports has increased utilization of the Partnership s existing export facilities and offers prospects for a longer term potential expansion of our Galena Park export facilities backed by precedent contracts. Finally, the Partnership s recently added petroleum products and crude storage and terminaling team closed its first acquisition in March, is pursuing organic expansion for that acquisition and is actively pursuing other refined products and crude storage and terminaling acquisition opportunities.

Strong supply and demand fundamentals for the Partnership s existing businesses. We believe that the current strength of oil, condensate and NGL prices and of forecast prices for these energy commodities has caused producers in and around the Partnership s 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 the Wolfberry and Canyon Sands plays, which are accessible by SAOU, the Wolfberry and Bone Springs plays, which are accessible by the Sand Hills plant and gathering 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. The Wolfberry, Canyon Sands, and Bone Springs plays are oil plays with associated gas containing high liquids content ranging from approximately 7.0 to 9.5 gal/Mcf. By comparison, the liquids content of the gas from the liquids rich portion of the

Eagle Ford Shale natural gas play is expected to average about 4 gal/Mcf. The Partnership has observed increased drilling permits and higher rig counts in these areas and expects these activities to result in higher inlet volumes over the next several years.

Producer activity in areas rich in oil, condensate and NGLs is 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. Until additional fractionation capacity comes on-line in 2011, there will be limited incremental supply of fractionation services in the area. These strong supply and demand fundamentals have resulted in long-term, frac-or-pay contracts for existing capacity and support the construction of new essentially fully committed fractionation capacity, such as the Partnership s CBF and GCF expansion projects. The Partnership is continuing to see rates for fractionation services increase. Existing fractionation customers are renewing contracts at market rates that are, in most cases, substantially higher than expiring rates for extended terms of up to ten years and with reservation fees that are paid even if customer volumes are not fractionated to ensure access to fractionation services. A portion of the recent and future expected increases in cash flow for the Partnership s fractionation business is related to high utilization and rollover of existing contracts to higher rates. The higher volumes of fractionated NGLs should also result in increased demand for other related fee-based services provided by the Partnership s Downstream Business.

Active drilling and production activity from liquids- rich shale gas 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 shale gas 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/other geologic cross-section combinations) and the Bone Springs/Avalon Shale plays. These shale gas and oil well resource plays all benefit from ongoing advances in geophysical, drilling and completion technologies first developed in shale gas plays. We believe that the Partnership s leadership position in the Downstream Business, which includes fractionation services, provides the Partnership with a competitive advantage relative to other gathering and processing companies without these capabilities. While we believe that the expected growth in the supply of liquids-rich gas from these plays will likely require the construction of (i) additional fractionation capacity, (ii) additional pipelines to transport the NGLs to and from major fractionation centers and (iii) additional natural gas gathering and processing facilities, the Partnership s active involvement in multiple potential projects does not guarantee that it will be involved with any such capacity expansions.

Potential third party acquisitions related to the Partnership s existing businesses. While the Partnership s recent growth has been partially driven by the implementation of a focused drop drown strategy, our management team also has a record of successful third party acquisitions. Since our formation, our strategy has included approximately $3 billion in third-party acquisitions and growth capital expenditures. This track record includes:

- The 2004 acquisition of SAOU and LOU from ConocoPhillips Company for $248 million;
- The 2004 acquisition of a 40% interest in Bridgeline Holdings, LP for $101 million from the Enron Corporation bankruptcy estate. Chevron Corporation, the other owner, exercised its rights under the partnership agreement to purchase the 40% stake from us for $117 million in 2005;
- The 2005 acquisition of Dynegy Midstream Services, Limited Partnership from Dynegy, Inc. for $2.4 billion;
- The 2008 acquisition of Chevron Corporation s 53.9% interest in VESCO; and
- The 2011 acquisition of the Channelview petroleum products and crude oil storage and terminaling facility.

We expect that third-party acquisitions will continue to be a significant focus of the Partnership s growth strategy.

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Competitive Strengths and Strategies

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

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 mixed NGL 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 their capacity. Our management has extensive experience in operating these assets and in permitting and building new midstream assets.

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 Canyon Sands, Bone Springs, Wolfberry and Barnett Shale plays is driven by the economics of current favorable oil, condensate and NGL prices and the high condensate and NGL content of the natural gas or associated natural gas streams. Increased drilling and production activities in these areas would likely increase the volumes of natural gas available to the Partnership s gathering and processing systems.

Comprehensive package of midstream services. The Partnership provides a comprehensive package of services to natural gas producers, including gathering, compressing, treating, processing and selling natural gas and storing, fractionating, treating, transporting and selling NGLs and NGL products. These services are essential to gather, process and treat wellhead gas to meet pipeline standards and to extract NGLs for sale into petrochemical, industrial and commercial markets. We believe the Partnership s ability to provide these integrated services provides an advantage in competing for new supplies of natural gas because the Partnership can provide substantially all of the services producers, marketers and others require for moving natural gas and NGLs from wellhead to market on a cost-effective basis. Additionally, 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 natural gas sector on a scale similar to the Partnership s are reasonably high.

Large, diverse business mix with favorable contracts. 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 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 (largely based on replacement cost economics), 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.

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), measurement (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.

Financial Flexibility. The Partnership has historically maintained strong financial metrics relative to its peer group, with leverage and distribution coverage ratios consistently above the peer group median. The Partnership also reduces 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 appropriate leverage and distribution coverage levels and mitigating commodity price volatility allow the Partnership to be flexible in its growth strategy and enable it to pursue strategic acquisitions and large growth projects.

Experienced and long-term focused management team. The executive management team that formed TRI in 2004 and continues to manage Targa today possesses over 200 years of combined experience working in the midstream natural gas and energy business. Additionally, other officers and key operational, commercial and financial employees provide depth of experience in the industry and with our assets and businesses.

Attractive Partnership Cash Flow Characteristics

We believe that 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 Natural Gas Gathering and Processing division has a favorable contract mix that is primarily percent-of-proceeds or hybrid which, along with its long-term commodity hedging program, serves to mitigate the impact of commodity price movements on cash flow. In the Partnership s Logistics and Marketing division, the majority of its revenues are derived under fee-based contracts.

The Partnership has hedged the commodity price risk associated with a portion of its expected natural gas, 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 its commodity risk management activities is to hedge the Partnership s 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 in the future by entering into similar hedge transactions as market conditions permit.

The Partnership also monitors its inventory levels with a view of mitigating losses related to downward price exposure.

The Partnership s annual maintenance capital expenditures have averaged approximately $54.0 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 capital expenditures will be sufficient for it to continue to operate these assets in a prudent and cost-effective manner.

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

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and development. Generally, higher oil and gas prices result in increased domestic oil and gas drilling and workover activity to increase production. The location of the Partnership s assets provides it with access to stable natural gas 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 incremental increases in volumes without significant capital investments. We believe that as domestic demand for natural gas and NGL grows over the long term, the Partnership s infrastructure will increase in value, as such infrastructure takes on increasing importance in meeting that demand.

While we have set forth the Partnership s strategies and competitive strengths above, its business involves numerous risks and uncertainties which may prevent the Partnership from executing its strategies or impact the amount of distributions to its unitholders. These risks include the adverse impact of changes in natural gas, NGL and condensate prices, its inability to access sufficient additional production to replace natural declines in production and the Partnership s dependence on a single natural gas producer for a significant portion of its natural gas supply. For a more complete description of the risks to which we and the Partnership are subject, see Risk Factors.

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

As of March 31, 2011, we and our directors and executive officers have a significant interest in the Partnership through our combined 13.9% limited partner interest and our 2% general partnership interest in the Partnership. In addition, we own incentive distribution rights that entitle us to receive an increasing percentage of quarterly distributions of the Partnership s available cash from its operating surplus after the minimum quarterly distribution and the target distribution levels have been achieved. We are party to an Omnibus Agreement with the Partnership that governs our relationship regarding certain reimbursement and indemnification matters. See Certain Relationships and Related Transactions Omnibus Agreement. We employ approximately 1,020 people who support primarily the Partnership s operations. See Employees. We allocate the cost of these employees to the Partnership in accordance with the Omnibus Agreement. Following the conveyance of all of our remaining operating assets to the Partnership in September 2010, substantially all of our general and administrative costs have been and will continue to be allocated to the Partnership, other than our direct costs of being a separate public reporting company.

The Partnership s Challenges

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

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

- The Partnership s cash flow is affected by supply and demand for oil, natural gas and NGL products and by natural gas and NGL 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 and NGLs, which depends on certain factors beyond its control. Any decrease in supplies of natural gas or NGLs could adversely affect the Partnership s business and operating results.

If the Partnership does not make investments in new assets or acquisitions 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 its 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 the Partnership s business and operating results.

For a further discussion of these and other challenges we and the Partnership face, please read Risk Factors.

Business Operations

The operations of the Partnership are reported in two divisions: (i) Natural Gas 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.

Natural Gas Gathering and Processing Division

The Partnership s Natural Gas Gathering and Processing division consists of gathering, compressing, dehydrating, treating, conditioning, processing, transporting and marketing natural gas. 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, commonly referred to as Mixed NGLs or Y-grade. 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 its facilities.

The Partnership continually seeks new supplies of natural gas, both to offset the natural declines in production from connected wells and to increase throughput volumes. The Partnership obtains additional 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 natural gas supplies is based primarily on location of assets, commercial terms, service levels and access to markets. The commercial terms of natural gas gathering and processing arrangements 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 the Partnership s extensive asset base and scope of operations in the regions in which the Partnership operates provide the Partnership with significant opportunities to add both new and existing natural gas production to its systems. We believe the Partnership s size and scope gives the Partnership a strong competitive position by placing it in close proximity to a large number of existing and new natural gas 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 the Partnership s ability to serve its customers needs across the natural gas and NGL value chain further augments the Partnership s ability to attract new customers.

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Field Gathering and Processing Segment

The Field Gathering and Processing segment gathers and processes 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 its gathering systems which, in aggregate, consist of approximately 10,100 miles of natural gas pipelines. The segment s processing plants include nine owned and operated facilities. For the year ended December 31, 2010, the Partnership processed an average of approximately 588 MMcf/d of natural gas and produced an average of approximately 71 MBbl/d of NGLs.

We believe the Partnership is well positioned as a gatherer and processor in the Permian and Fort Worth Basins. The Partnership has broad geographic scope, covering portions of 40 counties and approximately 18,100 square miles across these basins. We believe proximity to production and development provides the Partnership with a competitive advantage in capturing new supplies of natural gas because of the Partnership s 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, the Partnership 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 the Permian Business, Versado, SAOU and the North Texas System, each as described below.

Permian Business. The Permian Business consists of the Sand Hills gathering and processing system and the West Seminole and Puckett gathering systems. These systems consist of approximately 1,300 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 150 MMcf/d and residue gas connections to pipelines owned by affiliates of Enterprise Products Partners L.P. (Enterprise), ONEOK, Inc. (ONEOK) and El Paso Corporation (El Paso).

Versado. Versado consists of the Saunders, Eunice and Monument gas processing plants and related gathering systems in Southeastern New Mexico. The gathering systems consist of approximately 3,200 miles of natural gas gathering pipelines. The Saunders, Eunice and Monument refrigerated cryogenic processing plants have aggregate processing capacity of 280 MMcf/d (176 MMcf/d, net to the Partnership s ownership interest). These plants have residue gas connections to pipelines owned by affiliates of El Paso, MidAmerican Energy Company and Kinder Morgan Energy Partners, L.P. (Kinder Morgan). The Partnership s ownership in the Versado System 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 10 counties and approximately 4,000 square miles in West Texas, SAOU includes approximately 1,500 miles of pipelines in the Permian Basin that gather natural gas to the Mertzon and Sterling processing plants. SAOU is connected to numerous producing wells and central delivery points. SAOU has approximately 1,000 miles of low-pressure gathering systems and approximately 500 miles of high-pressure gathering pipelines to deliver the natural gas to the Partnership s processing plants. The gathering system has numerous compressor stations to inject low-pressure gas into the high-pressure pipelines. SAOU s processing facilities include two currently operating refrigerated cryogenic processing plants the Mertzon plant and the Sterling plant which have an aggregate processing capacity of approximately 110 MMcf/d. The system also includes the Conger cryogenic plant with a capacity of approximately 25 MMcf/d. The Partnership is in the process of restarting the Conger plant and anticipates completion by April 2011 and for it to provide for rapidly increasing volumes in SAOU. Additionally, two 15 MMcf/d processing trains from the Garden City plant are being refurbished for future use at another SAOU location.

North Texas System. The North Texas System includes two interconnected gathering systems with approximately 4,100 miles of pipelines, covering portions of 12 counties and approximately

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5,700 square miles, gathering wellhead natural gas for the Chico and Shackelford natural gas processing facilities.

The Chico Gathering System consists of approximately 2,000 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 Shackelford Gathering System consists of approximately 2,100 miles of intermediate-pressure gathering pipelines which 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 following table lists the Field Gathering and Processing segment s natural gas processing plants and related volumes for the year ended December 31, 2010:

Facility	% Owned	Location	Gross Processing Capacity (MMcf/d)	Gross Plant Natural Gas Inlet Throughput Volume (MMcf/d)	Gross NGL Production (MBbl/d)	Process Type[5]	Operated/ Non-operated
Permian Business							
Sand Hills	100.0	Crane, TX	150.0	116.5	14.4	Cryo	Operated
Other Permian[1]				12.3	0.4		
Versado							
Saunders[2]	63.0	Lea, NM	70.0			Cryo	Operated
Eunice[2]	63.0	Lea, NM	120.0			Cryo	Operated
Monument[2]	63.0	Lea, NM	90.0			Cryo	Operated
		Area Total	280.0	178.7	20.4		
SAOU							
Mertzon	100.0	Irion, TX	48.0			Cryo	Operated
Sterling	100.0	Sterling, TX	62.0			Cryo	Operated
Conger[3]	100.0	Sterling, TX	25.0			Cryo	Operated
		Area Total	135.0	99.8	20.7		
North Texas System							
Chico[4]	100.0	Wise, TX	265.0			Cryo	Operated
Shackelford	100.0	Shackelford, TX	13.0			Cryo	Operated
		Area Total	278.0	180.4	15.3		

Segment System Total	843.0	587.7	71.2

(1) Other Permian includes throughput other than plant inlet, primarily from compressor stations.

(2) These plants are part of the Partnership s Versado joint venture, of which the Partnership owns a 63.0% ownership interest, and volumes represent a 100% ownership interest.

(3) The Partnership is in the process of restarting the Conger plant, which we anticipate occurring in early 2011, to provide for rapidly increasing volumes in SAOU.

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

(5) Cryo Cryogenic Processing.

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., to many major gas markets across the U.S. through the mainline interstate pipeline network and to a substantial NGL distribution system with access to markets throughout Louisiana and the southeast U.S. The Coastal

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Gathering and Processing segment s assets consist of the Coastal Straddles and LOU, each as described below. For the year ended December 31, 2010, the Partnership processed an average of approximately 1,680 MMcf/d of plant natural gas inlet and produced an average of approximately 50 MBbl/d of NGLs.

Coastal Straddles. Coastal Straddles includes three wholly owned and operated gas processing plants Stingray, Barracuda and Lowry. Coastal Straddles also includes six operating partially-owned plants (one of which is operated by the Partnership) and the VESCO joint venture, which is operated by the Partnership. Coastal Straddles processes natural gas produced primarily from the central and western Gulf of Mexico, from both 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 it is interconnected. Coastal Straddles also includes the Pelican and Seahawk pipeline systems, which are non-FERC regulated gathering systems operated by the Partnership that have a combined length of approximately 175 miles and a combined capacity of approximately 230 MMcf/d. These systems gather natural gas from the shallow waters of the central Gulf of Mexico and supply a portion of the natural gas delivered to the Barracuda and Lowry processing facilities.

The Partnership owns a 77% interest in VESCO, a natural gas gathering and processing business, which includes our largest coastal straddle facility in terms of natural gas throughput and gross NGL production. The Partnership, through its interest in VESCO, also operates the Venice Gathering System (VGS), an offshore gathering system regulated as an interstate pipeline by FERC. VGS is approximately 150 miles in length and has a nominal capacity of 320 MMcf/d. VGS gathers natural gas from the shallow waters of the Gulf of Mexico and supplies a portion of the natural gas to the Venice gas plant.

LOU. LOU consists of approximately 850 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. These processing plants have an aggregate processing capacity of approximately 260 MMcf/d. In addition, the Gillis plant has integrated fractionation with operating capacity of approximately 13 MBbl/d.

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The following table lists the Coastal Gathering and Processing segment s natural gas processing plants for the year ended December 31, 2010:

Facility	% Owned	Location	Approximate Gross Processing Capacity (MMcf/d)	Gross Plant Natural Gas Inlet Throughput Volume (MMcf/d)	Gross NGL Production (MBbl/d)	Process Type[5]	Operated/ Non-operated
Coastal Straddles[1]							
Barracuda	100.0	Cameron, LA	190	138.0	3.3	Cryo	Operated
Lowry	100.0	Cameron, LA	265	110.8	2.8	Cryo	Operated
Stingray	100.0	Cameron, LA	300	269.3	4.7	RA	Operated
Calumet[2]	32.4	St. Mary, LA	1,650	128.2	2.9	RA	Non-operated
Yscloskey[2]	25.3	St. Bernard, LA	1,850	290.3	2.1	RA	Operated
Bluewater[2]	21.8	Acadia, LA	425			Cryo	Non-operated
Terrebonne[2]	4.8	Terrebonne, LA	950	22.4	0.9	RA	Non-operated
Toca[2]	10.7	St. Bernard, LA	1,150	50.8	1.3	Cryo/RA	Non-operated
Iowa[3]	100.0	Jeff. Davis, LA	500			Cryo	Operated
Sea Robin	0.8	Vermillion, LA	700	25.4	0.6	Cryo	Non-operated
VESCO	76.8	Plaquemines, LA	750	427.3	23.2	Cryo	Operated
Other				33.2	1.1		
		Area Total	8,730	1,495.7	42.9		
LOU							
Gillis[4]	100.0	Calcasieu, LA	180			Cryo	
Acadia	100.0	Acadia, LA	80			Cryo	
		Area Total	260	184.6	7.2		
	Consolidated System Total		8,990	1,680.3	50.1		

(1) Coastal Straddles also includes three offshore gathering systems which have a combined length of approximately 325 miles.

(2) Our ownership is adjustable and subject to annual redetermination.

(3) The Partnership has an option to acquire the Iowa Plant, which is not operating, from us.

(4) The Gillis plant has fractionation capacity of approximately 13 MBbl/d.

(5) Cryo Cryogenic Processing; RA Refrigerated Absorption Processing.

Logistics and Marketing Division

The Logistics and Marketing division is also referred to as the Downstream Business. It includes the activities necessary to convert mixed NGLs into NGL products, market the NGL products and provides certain value added services such as the fractionation, storage, terminaling, transportation, distribution and marketing of NGLs, as well as certain natural gas supply and marketing activities in support of the Partnership s other businesses. Through fractionation, mixed NGLs are separated into its component parts (ethane, propane, butanes and natural gasoline). These component parts are delivered to end-users through pipelines, barges, trucks and rail cars. End-users of component NGLs include petrochemical and refining companies and propane markets for heating, cooking or crop drying applications. Retail distributors often sell to end-use propane customers.

Logistics Assets Segment

This segment uses its platform of integrated assets to fractionate, store, treat and transport NGLs typically under fee-based and margin-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 Natural Gas Gathering and Processing assets and are primarily located at Mont Belvieu and Galena Park near Houston, Texas and in Lake Charles, Louisiana.

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, propane, butanes and natural gasoline. Mixed NGLs delivered from the Partnership s Field and Coastal Gathering and Processing segments represent the largest source of volumes processed by the Partnership s 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 also has an equity investment in a 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 the Partnership from participating in commercial decisions regarding rates paid by third parties for fractionation services at GCF. This restriction on the Partnerships 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 Partnership s Natural Gas 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 in areas of the U.S. that include North Texas, South Texas, Oklahoma and the Rockies and certain other basins accessed by pipelines to Mont Belvieu, as well as from continued production of NGLs in areas such as the Permian Basin, Mid-Continent, East Texas, South Louisiana and shelf and deepwater Gulf of Mexico. Dew point specifications implemented by individual pipelines and the policy statement enacted by 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 the Partnership access to both substantial sources of mixed NGLs and a large number of end-use markets.

Treating. 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 MBbls/d and is supported by fee-based contracts with Marathon Petroleum Company LLC and Koch Supply and Trading LP that have certain guaranteed volume commitments or provisions for deficiency payments.

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The following table details the Logistics Assets segment s fractionation and treating facilities:

Facility	% Owned	Maximum Gross Capacity (MBbls/d)	Gross Throughput for the Year Ended December 31, 2010 (MBbls/d)
Operated Facilities:			
Lake Charles Fractionator (Lake Charles, LA)	100.0	55.0	39.1
Cedar Bayou Fractionator (Mont Belvieu, TX)(1)	88.0	293.0	187.1
LSNG Hydrotreater (Mont Belvieu, TX)	100.0	30.0	18.0
Equity Fractionation Facilities (non-operated):			
Gulf Coast Fractionator (Mont Belvieu, TX)	38.8	109.0	98.9

(1) Includes ownership through 88% interest in Downstream Energy Ventures Co, LLC.

Storage and Terminaling. 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 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 the Partnership s customers. The Partnership provides long and short-term storage and terminaling services and throughput capability to third party customers for a fee.

The Partnership owns and/or operates a total of 39 storage wells that are in service at its facilities with a net storage capacity of approximately 65 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 in the NGL, petrochemical, refining, propane distribution and other related industries. 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 s fractionation, storage and terminaling business is supported by approximately 800 miles of company-owned pipelines to transport mixed NGLs and specification products.

The following table details the Logistics Assets segment s storage facilities at December 31, 2010:

NGL Storage Facilities

Facility	% Owned	County/Parish, State	Number of Permitted Wells	Gross Storage Capacity (MMBbl)
Hackberry Storage (Lake Charles)	100.0	Cameron, LA	12(1)	20.0
Mont Belvieu Storage	100.0	Chambers, TX	20(2)	41.4
Easton Storage	100.0	Evangeline, LA	1	0.8

(1) Four of twelve owned wells leased to CITGO under long-term leases; one of twelve currently in service.

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

The following table details the Logistics Assets segment s Terminal Facilities and our throughput for the year ended December 31, 2010:

Terminal Facilities

Facility	% Owned	County/Parish, State	Description	Throughput for 2010 (Million gallons)	Usable Storage Capacity (MMBbl)
Galena Park Terminal[1]	100	Harris, TX	NGL import / export terminal	916.8	0.7
Mont Belvieu Terminal[2]	100	Chambers, TX	Transport and storage terminal	2,406.0	48.9
Hackberry Terminal	100	Cameron, LA	Storage terminal	289.7	17.8
Targa Channelview Terminal[3]	100	Channelview, TX	Storage terminal / petroleum products and crude oil		544.0

(1) Volumes reflect total import and export across the dock/terminal.

(2) Volumes reflect total transport and terminal throughput volumes.

(3) Acquired in March 2011.

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 and New Jersey. The geographic diversity of the Partnership s assets provides it 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 and (iv) Commercial Transportation, 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, 2010, the Partnership s distribution and marketing services business sold an average of approximately 247 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 earns margins by purchasing and reselling NGL products in the spot and forward physical markets. To effectively serve its Distribution and Marketing customers, the Partnership contracts for and uses many of the assets included in its Logistics Assets segment. The Partnership also markets natural gas available from its Gathering and Processing segments, and purchases and resells natural gas in selected United States markets.

Wholesale Marketing. The Partnership s wholesale propane marketing operations primarily sells 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 its 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, the Partnership earns margin on a net-back 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 it serves and impact the ability to deliver propane to satisfy peak demand.

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Refinery Services. In its refinery services business, the Partnership typically provides NGL balancing services via contractual arrangements with refiners to purchase and/or market propane and to supply butanes. The Partnership uses its commercial transportation assets (discussed below) and contracts for and uses the storage, transportation and distribution assets included in its Logistics Assets segment to assist refinery customers in managing their NGL product demand and production schedules. This includes both feedstocks consumed in refinery processes and the excess NGLs produced by those same refining processes. Under typical net-back 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 net-back 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 its customers.

The Partnership s transportation assets, as of December 31, 2010, include:

- approximately 760 railcars that the Partnership leases and manages;
- approximately 70 owned and leased transport tractors and approximately 100 company-owned tank trailers; and
- 21 company-owned pressurized NGL barges.

Natural Gas Marketing. The Partnership also markets natural gas available to the Partnership 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:

Terminal Facilities

Facility	% Owned	County/Parish, State	Description	Throughput for Year Ended December 31, 2010(1) (Million gallons)	Usable Storage Capacity (Million gallons)
Calvert City Terminal	100	Marshall, KY	Propane terminal	47.2	0.1
Greenville Terminal	100	Washington, MS	Marine propane terminal	23.1	1.7
Port Everglades Terminal	100	Broward, FL	Marine propane terminal	23.8	1.7

Tyler Terminal	100	Smith, TX	Propane terminal	9.3	0.2
Abilene Transport[2]	100	Taylor, TX	Raw NGL transport terminal	12.4	Less than 0.1
Bridgeport Transport[2]	100	Jack, TX	Raw NGL transport terminal	49.6	0.1
Gladewater Transport[2]	100	Gregg, TX	Raw NGL transport terminal	20.5	0.4
Hammond Transport	100	Tangipahoa, LA	Transport terminal	31.6	No storage
Chattanooga Terminal	100	Hamilton, TN	Propane terminal	18.3	1.0
Sparta Terminal	100	Sparta, NJ	Propane terminal	10.7	0.2
Hattiesburg Terminal[3]	50	Forrest, MS	Propane terminal	264.8	269.6
Winona Terminal	100	Flagstaff, AZ	Propane terminal	4.4	0.3

(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 100% ownership.

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Operational Risks and Insurance

The Partnership is subject to all risks inherent in the midstream natural gas business. 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 these insurance coverages increased significantly following Hurricanes Katrina and Rita in 2005. Insurance premiums, deductibles and co-insurance requirements increased substantially, and terms were generally less favorable than terms that were obtained prior to those hurricanes. Insurance market conditions worsened again as a result of industry losses including those sustained from Hurricanes Gustav and Ike in September 2008, and as a result of volatile conditions in the financial markets. As a result, in 2009, the Partnership experienced further increases in deductibles and premiums, and further reductions in coverage and limits. During 2010, it saw the insurance market conditions improve slightly.

The occurrence of a significant event 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 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 s business operations and financial stability, particularly if an uninsured loss were to occur. No assurance can be given that we will be able to maintain these levels of insurance in the future at rates considered commercially reasonable, particularly named windstorm coverage and contingent business interruption coverage for the Partnership s onshore operations.

Significant Customers

The following table lists the percentage of the Partnership s consolidated sales and consolidated product purchases with the Partnership s significant customers and suppliers:

	Year Ended December 31,		
	2008	2009	2010
% of consolidated revenues CPC	19%	15%	10%
% of consolidated product purchases Louis Dreyfus Energy Services L.P.	9%	11%	10%

No other customer or supplier accounted for more than 10% of the Partnership s consolidated revenues or consolidated product purchases during these periods.

The Partnership has agreements with CPC, a separate joint venture affiliate of Chevron, pursuant to which the Partnership 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, CPC executed contracts to replace the previously terminated agreement with a new feedstock and storage agreement effective 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.

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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 its 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., GulfSouth Pipeline Company, LP, Hanlon Gas Processing, Ltd., J W Operating Company, Louisiana Intrastate Gas and several other interstate pipeline companies. Many of its competitors have greater financial resources than the Partnership 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 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. and ONEOK, Inc. 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.

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 NGA, and the 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 non-discriminatory 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.

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

Section 1(b) of the NGA, exempts natural gas gathering facilities from regulation as a natural gas company by FERC under the NGA. We believe that the natural gas pipelines in the Partnership s 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. 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.

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 daily scheduled flow and capacity posting requirements depending on the volume of flows in a given period and the design capacity of the pipelines receipt and delivery meters. 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 notes that the RRC is subject to a sunset condition. If the Texas Legislature does not take action to continue the RRC, the RRC will be abolished effective September 1, 2011, and will begin a one-year wind-down process. The Sunset Advisory Commission has recommended certain organizational changes be made to the RRC. The Partnership cannot tell what, if any, changes will be made to the RRC as a result of the pending regular session or any called sessions of the Texas Legislature in 2011, but the Partnership does not believe that any such changes would affect its business in a way that would be materially different from the way such changes would affect its competitors.

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 full 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.

Regulation of NGL intrastate pipelines

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 fractionator in Lake Charles, Louisiana, where the mixed NGLs streams are fractionated into various products. The Partnership delivers such refined 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.

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Natural Gas Processing

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

Availability, Terms and Cost of Pipeline Transportation

The Partnership s processing facilities and marketing of natural gas and NGLs are affected by the availability, terms and cost of pipeline transportation. The price and terms of access to pipeline transportation can be subject to extensive federal and, if a complaint is filed, state regulation. FERC is continually proposing and implementing new rules and regulations affecting the interstate transportation of natural gas, and to a lesser extent, the interstate transportation of NGLs. These initiatives also may indirectly affect the intrastate transportation of natural gas and NGLs under certain circumstances. We cannot predict the ultimate impact of these regulatory changes to the Partnership s processing operations and its natural gas and NGL marketing operations. We do not believe that the Partnership would be affected by any such FERC action materially differently than other natural gas processors and natural gas and NGL marketers with whom it competes.

The ability of the Partnership s processing facilities and pipelines to deliver natural gas into third-party natural gas pipeline facilities is directly impacted by the gas quality specifications required by those pipelines. In 2006, FERC issued a policy statement on provisions governing gas quality and interchangeability in the tariffs of interstate gas pipeline companies and a separate order declining to set generic prescriptive national standards. FERC strongly encouraged all natural gas pipelines subject to its jurisdiction to adopt, as needed, gas quality and interchangeability standards in their FERC gas tariffs modeled on the interim guidelines issued by a group of industry representatives, headed by the Natural Gas Council (NGC+ Work Group), or to explain how and why their tariff provisions differ. We do not believe that the adoption of the NGC+ Work Group s gas quality interim guidelines by a pipeline that either directly or indirectly interconnects with the Partnership s facilities would materially affect the Partnership s 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 it undertakes, the Partnership is required to observe anti-market manipulation laws and related regulations enforced by FERC and/or the 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

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matters. For additional information regarding the potential impact of federal, state or local regulatory measures on the Partnership s business, see Risk Factors Risks Related to Our Business.

Interstate Common Carrier Liquids Pipeline Regulation

As part of the Downstream Business acquired from us on September 24, 2009, the Partnership acquired Targa NGL Pipeline Company LLC (Targa NGL). Targa NGL is an interstate NGL common carrier subject to regulation by FERC under the ICA. Targa NGL owns a 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 20 inch diameter pipeline, each of which run between Mont Belvieu, Texas and Galena Park, Texas. The eight inch and the 20 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 non-discriminatory. All shippers on this pipeline are Partnership subsidiaries.

Other Federal Laws and Regulation Affecting Our Industry

Energy Policy 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 670 to implement the anti-market manipulation provision of EP Act of 2005. Order 670 makes it unlawful to: (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 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 now 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 704), the daily schedule flow and capacity posting requirements under Order 720, and the quarterly reporting requirement under Order 735. The anti-market manipulation rule and enhanced civil penalty authority reflect an expansion of FERC s NGA enforcement authority.

FERC Standards of Conduct for Transmission Providers

On October 16, 2008, FERC issued new standards of conduct for transmission providers (Order 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 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 717-A in a rehearing order, Order 717-B, on November 16, 2009 and in Order 717-C, on April 16, 2010. However, Orders 717-B and 717-C did not substantively alter the rules promulgated under Orders 717 and 717-A. Requests for rehearing of Order 717-C have been filed and are currently pending before FERC. Our only Transmission Provider, VGS, does not engage in any transactions with marketing affiliates, and we do not believe that our operations will be affected by the new standards of conduct. We have no way to predict with certainty whether and to what extent FERC will revise the new standards of conduct in response to those requests for rehearing.

FERC Market Transparency Rules

In 2007, FERC issued Order 704, whereby wholesale buyers and sellers of more than 2.2 BBtu 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 704 as clarified in orders on clarification and rehearing.

On November 20, 2008, FERC issued a final rule on daily scheduled flows and capacity posting requirements (Order 720). Under Order 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. 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 interstate transportation services under Section 311 of the NGPA and Hinshaw pipelines providing interstate transportation service subject to FERC jurisdiction 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 becomes 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 because they are not certificated to provide interstate transportation service. We will continue to monitor developments with respect to this rulemaking.

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, Health and Safety Matters

General

The Partnership s operations are subject to stringent and complex federal, state and local laws and regulations pertaining to health, safety and the environment. 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 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 re-interpretation of enforcement policies that result in more stringent and costly waste handling, storage, transport, disposal 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, natural resources or 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 conditions will continue in the future.

The following is a summary of the more significant existing environmental, 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 its capital expenditures, results of operations or financial position.

Hazardous Substances and Waste

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 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.

The Partnership also generates solid wastes, including hazardous wastes that are subject to the requirements of 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 its operations, the Partnership 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. Although the Partnership has utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or wastes may have been disposed of or released on or under the properties owned or leased by us or on or under the other locations where these hydrocarbons 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 wastes was not under the Partnership s control. These properties 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 could materially impact the Partnership s operations or financial condition.

Air Emissions

The 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 Partnership is currently reviewing the air emissions monitoring systems at certain of its facilities. The Partnership may be required to incur capital expenditures in the next few years to implement various air emissions leak detection and monitoring programs as well as to install air pollution control equipment or non-ambient storage tanks as a result of its review or in connection with maintaining, amending or obtaining operating permits and approvals for air emissions. We currently believe, however, that such requirements will not have a material adverse affect on the Partnership s operations.

Climate Change

There is increasing attention in the United States and worldwide concerning the issue of climate change and the effect of GHGs. 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. These findings allow the EPA to proceed with the adoption and implementation of regulations restricting emissions of GHGs under existing provisions of the federal Clean Air Act. The EPA already has adopted two sets of regulations regarding possible future regulation of GHG emissions under the Clean Air Act, one of which purports to regulate emissions of GHGs from motor vehicles and the other of which would regulate emissions of GHGs from large stationary sources of emissions, such as power plants or industrial facilities effective January 2, 2011. In June 2010, EPA published its final rule to address permitting of GHG emissions from stationary sources under the Clean Air Act s Prevention of Significant Deterioration (PSD) and Title V permitting programs. The final rule tailors the PSD and Title V permitting programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. The EPA s rules relating to emissions of GHGs from large stationary sources of emissions are currently subject to a number of legal challenges but the federal courts have thus far declined to issue any injunctions to prevent EPA from implementing or requiring state environmental agencies to implement the rules. Moreover, on October 30, 2009, the EPA published a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S. on an annual basis beginning in 2011 for emissions occurring in 2010. On November 8, 2010, the EPA adopted amendments to this GHG reporting rule, expanding the monitoring and reporting obligations to include 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, beginning in 2012 for emissions occurring in 2011.

In addition, the U.S. Congress has from time to time considered 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. Most of these cap and trade programs work by requiring either major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and NGL fractionation plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved. The adoption and implementation of any regulations imposing GHG reporting or permitting obligations on, or limiting emissions of GHGs from, the Partnership s equipment and operations could require the Partnership to incur costs to reduce emissions of GHGs associated with its operations, could adversely affect its performance of operations in the absence of any permits that may be required to regulate emission of greenhouse gases, or could adversely affect demand for its natural gas and NGL processing services.

Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events; if any such effects were to occur, they could have in adverse effect on the Partnership s assets and 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 U.S. 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 non-authorized discharges.

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. However, the EPA recently asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the SDWA s Underground Injection Control Program. While the EPA has yet to take any action to enforce or implement this newly asserted regulatory authority, industry groups have filed suit challenging the EPA s recent decision. At the same time, the EPA has commenced a study of the potential adverse impact of hydraulic fracturing activities, with the initial results of the study expected to be available in late 2012. Also, legislation was introduced in the recently completed session of Congress to amend the SDWA to subject hydraulic fracturing operations to regulation under the Act and to require the disclosure of chemicals used by the oil and natural gas industry, and such legislation could be introduced in the current session of Congress. Moreover, some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. 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 our revenues and results of operation by decreasing the volumes of natural gas that the Partnership gathers, processes and fractionates.

The 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 the Partnership s 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, SDWA, OPA and analogous state laws.

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. However, the designation of previously unidentified endangered or threatened species could cause the Partnership to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Pipeline Safety

The pipelines used by the Partnership to gather and 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

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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 and Louisiana have developed regulatory programs that parallel the federal regulatory scheme and are applicable to intrastate pipelines transporting natural gas and NGLs. We currently estimate an annual average cost of $2.2 million for years 2011 through 2013 to perform necessary integrity management program testing on the Partnership s 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.

More recently, on December 3, 2009, the PHMSA issued a final rule mandated by the PIPES Act focusing on how human interactions of control room personnel, such as avoidance of error or the performance of mitigating actions, may impact pipeline system integrity. Among other things, the final rule requires operators of hazardous liquid and gas pipelines to amend their existing written operations and maintenance procedures, operator qualification programs and emergency plans to take into account such items as specificity of the responsibilities and roles of control room personnel; listing of planned pipeline-related occurrences during a particular shift that may be easily shared with other controllers during a shift turnover; establishment of appropriate shift rotations to protect against controller fatigue; and development of appropriate communications between controllers, management and field personnel when planning and implementing changes to pipeline equipment or operations. We do not anticipate that the rule, as issued in final form, will result in substantial costs with respect to the Partnership s operations.

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

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the Partnership is 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 the Partnership in fee title, and we believe that the Partnership has satisfactory title to these lands. The remainder of the land on which the Partnership s plant sites and major facilities are located is held by the Partnership pursuant to ground leases between the Partnership, as lessee, and the fee owner of the lands, as lessors. The Partnership, or its predecessors, has leased these lands for many years without any material challenge known to us relating to the title to the land upon which the assets are located, and we believe that 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 or license held by the Partnership, and we believe that the Partnership has satisfactory title to all of its material leases, easements, rights-of-way, permits 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, causing 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 our holding of title to any part of such assets subject to future conveyance or as our nominee.

Employees

Through our subsidiaries, we employ approximately 1,020 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.

Legal Proceedings

On December 8, 2005, WTG filed suit in the 333rd District Court of Harris County, Texas against several defendants, including Targa and two other Targa entities and private equity funds affiliated with Warburg Pincus LLC, seeking damages from the defendants. The suit alleges that Targa and private equity funds affiliated with Warburg Pincus, along with ConocoPhillips Company (ConocoPhillips) and Morgan Stanley, tortiously interfered with (i) a contract WTG claims to have had to purchase SAOU from ConocoPhillips and (ii) prospective business relations of WTG. WTG claims the alleged interference resulted from Targa s competition to purchase the ConocoPhillips assets and its successful acquisition of those assets in 2004. In October 2007, the District Court granted defendants motions for summary judgment on all of WTG s claims. In February 2010, the 14th Court of Appeals affirmed the District Court s final judgment in favor of defendants in its entirety. In January 2011, the Texas Supreme Court denied WTG s petition for review of the lower court s judgment and in March 2011, the Texas Supreme Court denied WTG s motion for rehearing of the Court s denial to review WTG s appeal. We have agreed to indemnify the Partnership for any claim or liability arising out of the WTG suit.

Except as provided above, neither we nor the Partnership is a party to any other legal proceedings other than legal proceedings arising in the ordinary course of our business. The Partnership is a party to various administrative and regulatory proceedings that have arisen in the ordinary course of its business. See Regulation of Operations and Environmental, Health and Safety Matters.

MANAGEMENT

Targa Resources Corp.

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

Our directors hold office until the earlier of their death, resignation, removal or disqualification or until their successors have been elected and qualified. Officers serve at the discretion of the board of directors. There are no family relationships among any of our directors or executive officers. Please read Certain Relationships and Related Transactions Stockholders Agreement for a discussion of arrangements among our stockholders pursuant to which our directors were selected prior to our IPO. The following table sets forth certain information with respect to our directors, executive officers and other officers as of March 31, 2011.

Name	Age	Position
Rene R. Joyce	63	Chief Executive Officer and Director
James W. Whalen	69	Executive Chairman and Director
Joe Bob Perkins	50	President
Jeffrey J. McParland	56	President-Finance and Administration
Roy E. Johnson	66	Executive Vice President
Michael A. Heim	62	Executive Vice President and Chief Operating Officer
Paul W. Chung	51	Executive Vice President, General Counsel and Secretary
Matthew J. Meloy	33	Senior Vice President and Chief Financial Officer
John R. Sparger	57	Senior Vice President and Chief Accounting Officer
Charles R. Crisp	63	Director
In Seon Hwang	34	Director
Peter R. Kagan	42	Director
Chris Tong	54	Director
Ershel C. Redd Jr.	63	Director

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

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

Joe Bob Perkins has served as President of the Company since its formation on October 27, 2005, of the General Partner since October 2006 and of TRI since February 2004 and was a consultant for the TRI predecessor company during 2003. Mr. Perkins also served as a consultant in the energy industry from 2002 through 2003 and was an active partner in RTM Media (an outdoor advertising firm) during such time period. Mr. Perkins served as President and Chief Operating Officer for the Wholesale Businesses, Wholesale Group and Power Generation Group of Reliant Resources, Inc. and its parent/predecessor companies, from 1998 to 2002 and Vice President, Corporate Planning and Development, of Houston Industries from 1996 to 1998. He served as Vice President, Business Development, of Coral from 1995 to 1996 and as Director, Business Development, of Tejas from 1994 to 1995. Prior to 1994, Mr. Perkins held various positions with the consulting firm of McKinsey & Company and with an exploration and production company.

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

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

Jeffrey J. McParland has served as President-Finance and Administration of the Company and TRI since October 25, 2010 and of the General Partner since December 15, 2010. He has also served as a director of TRI since December 16, 2010. Mr. McParland served as Executive Vice President and Chief Financial Officer of the Company between October 27, 2005 and October 25, 2010 and of TRI between April 2004 and

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

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

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

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

Charles R. Crisp has served as a director of the Company since its formation on October 27, 2005 and of TRI between February 2004 and December 16, 2010. Mr. Crisp was President and Chief Executive Officer of Coral Energy, LLC, a subsidiary of Shell Oil Company from 1999 until his retirement in November 2000, and was President and Chief Operating Officer of Coral from January 1998 through February 1999. Prior to this, Mr. Crisp served as President of the power generation group of Houston Industries and, between 1988 and 1996, as President and Chief Operating Officer of Tejas. Mr. Crisp is also a director of AGL Resources Inc., EOG Resources Inc. and Intercontinental Exchange, Inc. Mr. Crisp brings extensive energy experience, a vast understanding of many aspects of our industry and experience serving on the boards of other public companies in the energy industry. His leadership and business experience and deep knowledge of various sectors of the energy industry bring a crucial insight to the board of directors.

In *Seon Hwang* has served as a director of the Company since May 2006, of TRI between May 2006 and December 16, 2010, and of the General Partner since February 2011. Mr. Hwang is a Member and Managing Director of Warburg Pincus LLC and a general partner of Warburg Pincus & Co., where he has

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been employed since 2004, and became a partner of Warburg Pincus & Co. in 2009. Prior to joining Warburg Pincus, Mr. Hwang worked at GSC Partners, a distressed investment firm, from 2002 until 2004, the M&A group at Goldman Sachs from 1998 to 2000, and the Boston Consulting Group from 1997 to 1998. He is also a director of Competitive Power Ventures and serves on the investment committee of Sheridan Production Partners LLC. Mr. Hwang serves as a director because certain investment funds managed by Warburg Pincus LLC, for whom Mr. Hwang is a managing director and member, control us through their ownership of securities in Targa Resources Corp. Mr. Hwang has significant experience with energy companies and investments and broad familiarity with the industry and related transactions and capital markets activity, which enhance his contributions to the board of directors.

Peter R. Kagan has served as a director of the Company since its formation on October 27, 2005, of the General Partner since February 2007 and of TRI between February 2004 and December 2010. Mr. Kagan is a member and Managing Director of Warburg Pincus LLC and a general partner of Warburg Pincus & Co., where he has been employed since 1997 and became a partner of Warburg Pincus & Co. in 2002. He is also a member of Warburg Pincus Executive Management Group. He is also a director of Antero Resources Corporation, Broad Oak, Canbriam Energy, Fairfield Energy Limited, Laredo Petroleum and MEG Energy Corp. Mr. Kagan serves as a director because certain investment funds managed by Warburg Pincus LLC, for whom Mr. Kagan is a managing director and member, control us through their ownership of securities in Targa Resources Corp. Mr. Kagan has significant experience with energy companies and investments and broad familiarity with the industry and related transactions and capital markets activity, which enhance his contributions to the board of directors.

Chris Tong has served as a director of the Company since January 2006 and of TRI between January 2006 and December 16, 2010. Mr. Tong is a director of Cloud Peak Energy Inc. and Kosmos Energy Holdings. He served as Senior Vice President and Chief Financial Officer of Noble Energy, Inc. from January 2005 until August 2009. He also served as Senior Vice President and Chief Financial Officer for Magnum Hunter Resources, Inc. from August 1997 until December 2004. Prior thereto, he was Senior Vice President of Finance of Tejas Acadian Holding Company and its subsidiaries, including Tejas Gas Corp., Acadian Gas Corporation and Transok, Inc., all of which were wholly-owned subsidiaries of Tejas Gas Corporation. Mr. Tong held these positions from August 1996 until August 1997, and had served in other treasury positions with Tejas since August 1989. Mr. Tong brings a breadth and depth of experience as a chief financial officer in the energy industry, a financial executive, a director of another public company and member of another audit committee. He brings significant financial, capital markets and energy industry experience to the board and in his position as the chairman of our Audit Committee.

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

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Board of Directors

Our board of directors consists of seven members. Please read Certain Relationships and Related Transactions Stockholders Agreement for a description of arrangements pursuant to which our directors were elected prior to the completion of our IPO. The board reviewed the independence of our directors using the independence standards of the NYSE and various other factors discussed under Certain Relationships and Related Transactions Director Independence and, based on this review, determined that Messrs. Crisp, Hwang, Kagan, Redd and Tong are independent within the meaning of the NYSE listing standards currently in effect.

Our directors are divided into three classes serving staggered three-year terms. Class I, Class II and Class III directors will serve until our annual meetings of stockholders in 2011, 2012 and 2013, respectively. The Class I directors are Messrs. Crisp and Whalen, the Class II directors are Messrs. Redd and Hwang and the Class III directors are Messrs. Kagan, Tong and Joyce. At each annual meeting of stockholders, directors will be elected to succeed the class of directors whose terms have expired. This classification of our board of directors could have the effect of increasing the length of time necessary to change the composition of a majority of the board of directors. In general, at least two annual meetings of stockholders will be necessary for stockholders to effect a change in a majority of the members of the board of directors.

Committees of the Board of Directors

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

Audit Committee

The members of our Audit Committee are Messrs. Tong, Redd and Crisp. Mr. Tong is the Chairman of this committee. Our board of directors has affirmatively determined that Messrs. Crisp, Redd, and Tong are independent as described in the rules of the NYSE and the Securities Exchange Act of 1934, as amended (the Exchange Act). Our board of directors has also determined that, based upon relevant experience, Mr. Tong is an audit committee financial expert as defined in Item 407 of Regulation S-K of the Exchange Act.

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

Compensation Committee

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

Nominating and Governance Committee

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

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

Conflicts Committee

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

Compensation Committee Interlocks and Insider Participation

No member of our Compensation Committee has been at any time an employee of ours. None of our executive officers served on the board of directors or compensation committee of a company that has an executive officer that served on our board or Compensation Committee. No member of our board is an executive officer of a company in which one of our executive officers serves as a member of the board of directors or compensation committee of that company.

Messrs. Kagan and Joung, both of whom were members of our Compensation Committee during 2010, were affiliates of Warburg Pincus during 2010. Mr. Joung resigned from our Compensation Committee in February 2011. Messrs. Kagan and Joung were directors of Broad Oak during 2010, from whom we bought natural gas and NGL products and in which affiliates of Warburg Pincus own a controlling interest. Messrs. Kagan and Joung are party to indemnification agreements with us. Warburg Pincus was a party to the Stockholders Agreement and is a party to the Registration Rights Agreement with us. The Stockholders Agreement was terminated in connection with the IPO. Mr. Kagan was also a director of Antero Resources Corporation (Antero) during 2010, from whom we bought natural gas and NGL products and in which affiliates of Warburg Pincus own a controlling interest. Please read Certain Relationships and Related Transactions for a description of these transactions.

Code of Business Conduct and Ethics

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

Corporate Governance Guidelines

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

Executive Compensation

Compensation Discussion and Analysis

The following discussion and analysis contains statements regarding our and our executive officers future performance targets and goals. These targets and goals are disclosed in the limited context of our

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compensation programs and should not be understood to be statements of management s expectations or estimates of results or other guidance.

Overview

Prior to our IPO in December 2010, under the terms of our Amended and Restated Stockholders Agreement, as amended (the Stockholders Agreement) that was in effect until the closing of the IPO, compensatory arrangements with our executive officers identified in the Summary Compensation Table (named executive officers) were required to be submitted to a vote of our stockholders unless such arrangements were approved by the Compensation Committee (the Compensation Committee) of our board of directors. As such, the Compensation Committee was responsible for overseeing the development of an executive compensation philosophy, strategy, framework and individual compensation elements for our named executive officers that were based on our business priorities.

The Stockholders Agreement terminated upon completion of the IPO. Compensatory arrangements with our named executive officers will remain the responsibility of our Compensation Committee.

The following Compensation Discussion and Analysis describes the material elements of compensation for our named executive officers as determined by the Compensation Committee.

Compensation Philosophy

The Compensation Committee believes that total compensation of executives should be competitive with the market in which we compete for executive talent which encompasses not only midstream natural gas companies, but also other energy industry companies as described in The Role of Peer Groups and Benchmarking below. The following compensation objectives guide the Compensation Committee in its deliberations about executive compensation matters:

- provide a competitive total compensation program that enables us to attract and retain key executives;
- ensure an alignment between our strategic and financial performance and the total compensation received by our named executive officers;
- provide compensation for performance that reflects individual and company performance both in absolute terms and relative to our peer group;
- ensure a balance between short-term and long-term compensation while emphasizing at-risk or variable, compensation as a valuable means of supporting our strategic goals and aligning the interests of our named executive officers with those of our shareholders; and
- ensure that our total compensation program supports our business objectives and priorities.

Consistent with this philosophy and compensation objectives, we do not pay for perquisites for any of our named executive officers, other than parking subsidies.

The Role of Peer Groups and Benchmarking

Our Chief Executive Officer (the CEO), President and President Finance and Administration (collectively, Senior Management) review compensation practices at peer companies, as well as broader industry compensation practices, at a general level and by individual position to ensure that our total compensation is reasonably comparable to industry practice and meets our compensation objectives. In addition, when evaluating compensation levels for each named executive officer, the Compensation Committee reviews publicly available compensation data for executives in our peer group, compensation surveys and compensation levels for each named executive officer with respect to their roles and levels of responsibility, accountability and decision-making authority. Although Senior Management and the Compensation Committee consider compensation data from other companies,

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they do not attempt to set compensation components to meet specific benchmarks, such as salaries above the median or total compensation at the 50th percentile. The peer company data that is reviewed by Senior Management and the Compensation Committee is simply one factor out of many that is used in connection with the establishment of the compensation for our officers. The other factors considered by Senior Management and the Compensation Committee include, but are not limited to, (i) available compensation data about rankings and comparisons, (ii) effort and accomplishment on a group basis, (iii) challenges faced and challenges overcome, (iv) unique skills, (v) contribution to the management team and (vi) the perception of both the board of directors and the Compensation Committee of performance relative to expectations, actual market/business conditions and peer company performance. All of these factors, including peer company data, are utilized in a subjective assessment of each year s decisions relating to annual cash incentives, long-term incentives and base compensation changes with a view towards total compensation and pay-for-performance.

As part of the annual review process conducted in 2009 for 2010 compensation, Senior Management identified peer companies in the midstream energy industry and reviewed compensation information filed by the peer companies with the SEC. The peer group reviewed by Senior Management and the Compensation Committee for 2010 consisted of the following companies: Atlas Pipeline Partners, L.P., Copano Energy L.L.C., Crosstex Energy, L.P., DCP Midstream Partners LP, Enbridge Energy Partners LP, Energy Transfer Partners, LP, Magellan Midstream Partners LP, MarkWest Energy Partners, LP, Martin Midstream Partners, NuStar Energy, ONEOK Partners, LP, Plains All American Pipeline Partners, LP, Regency Energy Partners LP, TEPPCO Partners and Williams Partners LP. During the second quarter of 2010, following its initial review relating to 2010 compensation, the Compensation Committee engaged BDO USA, LLP (BDO), a compensation consultant, to conduct a new review of executive and key employee compensation to help it assure that compensation goals were being met and that the most recent trends in compensation were appropriately considered. In this additional review process, the peer companies were reassessed to determine whether the peer groups for long-term cash incentive awards (performance units) and for compensation comparison and analysis remained appropriate and adequately reflected the market for executive talent. As a result, the peer group used for long-term cash incentive awards and for compensation comparison was expanded and weighted to include energy companies other than midstream master limited partnerships (MLPs) to better reflect the market for executive talent in the energy industry. Because many companies in the expanded peer group are larger than the Company as measured by market capitalization and total assets, with the assistance of BDO, compensation data for the peer companies was analyzed using multiple regression analysis to develop a prediction of the total compensation that peer companies of comparable size to the Company would offer similarly-situated executives. This regressed data was then weighted as follows to develop a reference point for judging the adequacy of executive pay at the Company: MLPs (given a 70% weighting), exploration and production companies (E&Ps) (given a 15% weighting) and utility companies (given a 15% weighting). The peer group companies in each of the three categories are:

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

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

Utility peer companies: Centerpoint Energy Inc., El Paso Corp., Enbridge Inc., EQT Corp., National Fuel Gas Co., NiSource Inc., ONEOK Inc., Questar Corp., Sempra Energy, Spectra Energy Co., Southern Union Co. and Williams Companies Inc.

Senior Management and the Compensation Committee review our compensation practices and performance against peer companies on at least an annual basis.

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Role of Senior Management in Establishing Compensation for Named Executive Officers

Typically, Senior Management consults with BDO, the compensation consultant engaged by the Compensation Committee, and reviews market data to determine relevant compensation levels and compensation program elements. Based on these consultations and a review of publicly available information for the peer group, Senior Management submits emerging conclusions and later a proposal to the chairman of the Compensation Committee. The proposal includes a recommendation of base salary, annual bonus and any new long-term compensation to be paid or awarded to executive officers and employees. The chairman of the Compensation Committee reviews and discusses the proposal with Senior Management and the consultant and may discuss it with the other members of the Compensation Committee, other board members, or the full boards of the Company and Targa Resources GP LLC and may request that Senior Management provide him with additional information or reconsider their proposal. The resulting recommendation is then submitted to the Compensation Committee for consideration, which also meets separately with the compensation consultant. The final compensation decisions are reported to the Board.

The Compensation Committee may delegate the approval of award grants and other transactions and responsibilities regarding the administration of compensatory programs to the Chairman of the Board of Directors or the Chief Executive Officer, provided that such administration and approval of awards does not apply for our Section 16 officers. Further, our Senior Management has no other role in determining compensation for our named executive officers, but our executive officers are delegated the authority and responsibility to determine the compensation for all other employees.

Elements of Compensation for Named Executive Officers

Our compensation philosophy for executive officers emphasizes our executives having a significant long-term equity stake. For this reason, in connection with TRI Resources Inc. s formation in 2004 and with our acquisition of Dynegy Midstream Services, Limited Partnership from Dynegy, Inc. in 2005, the named executive officers were granted restricted stock and options to purchase restricted stock to attract, motivate and retain our executive team. In connection with the IPO, the named executive officers were granted additional shares of bonus stock as an additional recognition for past performance and positioning to this point in time and restricted stock as one-time retention and incentive awards in connection with our transition from a private to a public company. Both of these equity awards align our executive officers interests with those of stockholders. Our executive officers have also invested a significant portion of their personal investable assets in our equity and have made significant investments in the equity of the Partnership. With these equity interests as context, elements of compensation for our named executive officers are the following: (i) annual base salary; (ii) discretionary annual cash awards; (iii) performance awards under our long-term incentive plan, (iv) awards under our new stock incentive plan; (v) contributions under our 401(k) and profit sharing plan; and (vi) participation in our health and welfare plans on the same basis as all of our other employees.

Base Salary. The base salaries for our named executive officers are set and reviewed annually by the Compensation Committee. The salaries are intended to provide fixed compensation based on historical salaries paid to our named executive officers for services rendered to us, market data on compensation paid to similarly situated executives and responsibilities and performance of our named executive officers.

Annual Cash Incentives. The discretionary annual cash awards available to our named executive officers provide an opportunity to supplement the annual base salary of our named executive officers so that, on a combined basis, the annual cash compensation opportunity for our named executive officers yields competitive cash compensation levels and drives performance in support of our business strategies. It is our general policy to pay these awards prior to the end of the first quarter of the fiscal year following the fiscal year to which they related. The payment of individual cash bonuses to executive management, including our named executive officers, is subject to the sole discretion of the Compensation Committee.

The discretionary annual cash awards are designed to reward our employees for contributions towards our achievement of financial and operational business priorities (including business priorities of

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the Partnership) approved by the Compensation Committee and to aid us in retaining and motivating employees. These priorities are not objective in nature they are subjective and performance in regard to these priorities is ultimately evaluated by the Compensation Committee in its sole discretion. The approach taken by the Compensation Committee in reviewing performance against the priorities is along the lines of grading a multi-faceted essay rather than a simple true/false exam. As such, success does not depend on achieving a particular target; rather, success is determined based on past norms, expectations and unanticipated obstacles or opportunities that arise. For example, hurricanes and deteriorating market conditions may alter the priorities initially established by the Compensation Committee such that certain performance that would otherwise be deemed a negative may, in context, be a positive result. This subjectivity allows the Compensation Committee to account for the full industry and economic context of our actual performance or that of our personnel. The Compensation Committee considers all strategic priorities and reviews performance against the priorities but does not assign specific weightings to the strategic priorities in advance.

Under plans to pay a discretionary annual cash award that have been adopted and may be adopted in subsequent years, funding of a discretionary cash bonus pool is expected to be recommended by our Senior Management and approved by the Compensation Committee annually based on our achievement of certain strategic, financial and operational objectives. Such plans are and will be approved by the Compensation Committee, which considers certain recommendations by our Senior Management. Near or following the end of each year, Senior Management recommends to the Compensation Committee the total amount of cash to be allocated to the bonus pool based upon our overall performance relative to these objectives. Upon receipt of our Senior Management s recommendation, the Compensation Committee, in its sole discretion, determines the total amount of cash to be allocated to the bonus pool. Additionally, the Compensation Committee, in its sole discretion, determines the amount of the cash bonus award to each of our executive officers, including the CEO. The executive officers determine the amount of the cash bonus pool to be allocated to our departments, groups and employees (other than our executive officers) based on performance and on the recommendation of their supervisors, managers and line officers.

Stock Option Grants. Under our 2005 Stock Incentive Plan, as amended (the 2005 Incentive Plan), incentive stock options and non-incentive stock options to purchase, in the aggregate, up to 2,536,969 shares of our restricted stock may be granted to our employees, directors and consultants. No option awards have been granted to the named executive officers since 2005 under the 2005 Incentive Plan and option awards that were previously granted to our named executive officers under the 2005 Incentive Plan and that were outstanding upon the closing of the IPO were surrendered and cancelled. We will no longer make grants under the 2005 Incentive Plan.

Restricted Stock Grants. Under the 2005 Incentive Plan, up to 3,586,236 shares of our restricted stock may be granted to our employees, directors and consultants. No restricted stock awards have been granted to the named executive officers under the 2005 Stock Incentive Plan since 2005. We will no longer make grants under the 2005 Incentive Plan.

New Incentive Plan. In connection with the IPO, we adopted the 2010 Stock Incentive Plan (the 2010 Incentive Plan) under which we may grant to the named executive officers, other key employees, consultants and directors certain awards, including restricted stock and performance awards. The 2010 Incentive Plan provides for discretionary grants of the following types of awards: (a) incentive stock options qualified as such under U.S. federal income tax laws, (b) stock options that do not qualify as incentive stock options, (c) phantom stock awards, (d) restricted stock awards, (e) performance awards, (f) bonus stock awards, or (g) any combination of such awards. The maximum aggregate number of shares of our common stock that may be granted in connection with awards under the 2010 Incentive Plan is 5 million, of which approximately 1.9 million shares were awarded in connection with our IPO. A restricted stock award is a grant of shares of common stock subject to a risk of forfeiture, restrictions on transferability, and any other restrictions imposed by the Compensation Committee in its discretion. Except as otherwise provided under the terms of the 2010 Incentive Plan or an award agreement, the holder of a restricted stock award may have rights as a stockholder, including the right to vote or to receive dividends (subject to any mandatory reinvestment or other requirements imposed by the Compensation Committee). A restricted stock award

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that is subject to forfeiture restrictions may be forfeited and reacquired by us upon termination of employment or services. Common stock distributed in connection with a stock split or stock dividend, and other property distributed as a dividend, may be subject to the same restrictions and risk of forfeiture as the restricted stock with respect to which the distribution was made. Bonus stock awards under the 2010 Incentive Plan are awards of our common stock. These awards are granted on such terms and conditions and at such purchase price (if any) determined by the Compensation Committee and need not be subject to performance criteria, objectives, or forfeiture. Additional details relating to shares of restricted stock and bonus stock granted under the 2010 Incentive Plan are included below under Application of Compensation Elements Equity Ownership and Executive Compensation Outstanding Equity Awards a 2010 Fiscal Year-End.

LTIP Awards. We may grant to the named executive officers and other key employees performance unit awards linked to the performance of the Partnership s common units, with the amounts vesting under such awards dependent on the Partnership s performance compared to a peer-group consisting of the Partnership and 12 other publicly traded partnerships. These awards, which may be settled in cash or equity, are designed to further align the interests of the named executive officers and other key employees with those of the Partnership s equity holders. Additional details relating to our peer group applicable to LTIP awards payouts are included below under Application of Compensation Elements Long-Term Cash Incentives.

Retirement Benefits. We offer eligible employees a Section 401(k) tax-qualified, defined contribution plan (the 401(k) Plan) to enable employees to save for retirement through a tax-advantaged combination of employee and Company contributions and to provide employees the opportunity to directly manage their retirement plan assets through a variety of investment options. Our employees, including our named executive officers, are eligible to participate in our 401(k) Plan and may elect to defer up to 30% of their annual compensation on a pre-tax basis and have it contributed to the plan, subject to certain limitations under the Internal Revenue Code of 1986, as amended (the Code). In addition, we make the following contributions to the 401(k) Plan for the benefit of our employees, including our named executive officers: (i) 3% of the employee s eligible compensation; and (ii) an amount equal to the employee s contributions to the 401(k) Plan up to 5% of the employee s eligible compensation. We may also make discretionary contributions to the 401(k) Plan for the benefit of employees depending on our performance.

Health and Welfare Benefits. All full-time employees, including our named executive officers, may participate in our health and welfare benefit programs, including medical, health, life insurance and dental coverage and disability insurance.

Perquisites. We believe that the elements of executive compensation should be tied directly or indirectly to the actual performance of the Company. It is the Compensation Committee s policy not to pay for perquisites for any of our named executive officers, other than parking subsidies.

Relation of Compensation Elements to Compensation Philosophy

Our named executive officers, other executives and Section 16 officers and directors, through a combination of personal investment and equity grants, own approximately 13.9% of our fully diluted equity. Based on our named executive officers ownership interests in us and their direct ownership of the Partnership s common units, they own, directly and indirectly, approximately 0.4% of the Partnership s limited partner interests. The Compensation Committee believes that the elements of its compensation program fit the established overall compensation objectives in the context of management s substantial ownership of our equity, which allows us to provide competitive compensation opportunities to align and drive the performance of the named executive officers in support of our and the Partnership s business strategies and to attract, motivate and retain high quality talent with the skills and competencies required by us and the Partnership.

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Application of Compensation Elements

Equity Ownership. Historically, we have used both stock options and restricted stock to compensate our employees, including our named executive officers. Based on recommendations by our compensation consultant after completing the second quarter compensation review**,** we currently expect awards under our incentive plans to consist primarily of restricted stock, restricted units and performance based awards of restricted stock or units or cash-settled performance units rather than stock options or unit options. In connection with the IPO, our employees, including the named executive officers, were granted an aggregate of approximately 1.9 million shares of restricted stock and bonus stock under the 2010 Incentive Plan. Of these initial awards, our named executive officers were granted shares of restricted stock and bonus stock as follows: (i) with respect to restricted stock: Mr. Joyce 121,125 shares; Mr. Perkins 67,980 shares; Mr. Whalen 67,980 shares; Mr. Heim 60,885 shares; Mr. McParland 56,100 shares; and Mr. Meloy 22,425 shares and (ii) with respect to bonus stock: Mr. Joyce 122,439 shares; Mr. Perkins 106,200 shares; Mr. Whalen 106,200 shares; Mr. Heim 61,825 shares; and Mr. McParland 87,642 shares. The restricted stock awards have vesting restrictions. The restricted stock awards ((i) above) to executive officers and other key employees were made based upon the recommendation of BDO using market-based precedent and market-based amounts to provide a one-time retention and incentive award in connection with our transition from a private to a public company. The awards to the executive officers were established using a market-based multiple of 3X annual target long-term incentive compensation for each individual. BDO concluded that at the proposed 3X annual target long-term incentive level, the awards for executive management were of lesser value than grants awarded to senior executives in connection with other recent industry transactions over the last three years and that the value of the overall program available to executive officers would fall in a range between the 50th and 75th percentile of the expanded peer group over the next three years. The comparable transactions included the merger of MarkWest Hydrocarbons with MarkWest Energy Partners, L.P., the acquisition of the controlling interest of Buckeye GP Holding by BGHGP Holdings, LLC, the merger of Inergy L.P. and Inergy LP Holdings, the acquisition of Genesis Energy s general partner from Denbury Resources by Quintana Energy Investor Group and transactions involving Precision Drilling, Apache, RRI Energy, Approach Resources, Concho Resources, Encore Energy Partners, and Vanguard Natural Resources. The bonus stock awards ((ii) above) were fully vested on the date of grant. Both of these awards are intended to align the interests of key employees (including our named executive officers) with those of our stockholders. Therefore, participants (including our named executive officers) did not pay any consideration for the common stock they received with respect to these awards, and we did not receive any cash remuneration for the common stock delivered with respect to these awards. Partially as a result of the overall award structure, our named executive officers, as well as all other holders, of outstanding out-of-the-money options that were granted under the 2005 Incentive Plan cancelled those options.

The Compensation Committee also made cash bonus awards to our executive officers, including our named executive officers, in connection with the IPO in the aggregate amount of $3 million. After the internal reallocation described below, the cash awards to our named executive officers were as follows: Mr. Heim $732,000.

The bonus stock awards and the cash bonus awards were granted to the seven-person executive management team to provide (i) a higher carry of their equity interests and (ii) additional discretionary compensation, in each case in recognition of our executive management team s efforts in bringing us to this point in our successful history. The initial allocation among the seven persons of the bonus stock awards and $3 million cash bonus awarded to the executive team was initially based on the relative current base compensation of each individual. Our board of directors and the Compensation Committee allowed a voluntary reallocation of equity for cash among the members of the executive management group to accommodate individual preferences. The named executive officers, other than Mr. Heim, elected to exchange their portion of the cash bonus for additional equity and Mr. Heim and our two other executive officers elected to exchange some of their equity for larger shares of the cash bonus. The final allocation for the named executive officers is shown above. The amounts of restricted stock, bonus stock and cash bonus

awards were determined pursuant to our compensation philosophy and the compensation review discussed above.

Base Salary. In 2010, base salaries for our named executive officers were established based on historical levels for these officers, taking into consideration officer salaries in our peer group and the value of the total compensation opportunities available to our executive officers including the long-term equity component of our compensation program. As described above, the second quarter compensation review indicated that the compensation for our named executive officers was not consistent with compensation paid at MLP peer companies or with our expanded peer group generally when the data is adjusted for company size. In order to begin closing this gap in compensation, the Compensation Committee authorized the following increased base salaries for our named executive officers effective July 1, 2010.

Rene R. Joyce	$ 475,000
Jeffrey J. McParland	340,000
Joe Bob Perkins	412,000
James W. Whalen	412,000
Michael A. Heim	369,000
Matthew J. Meloy	207,500

Annual Cash Incentives. The Compensation Committee approved our 2010 Annual Incentive Plan (the Bonus Plan) in February 2010 with the following nine key business priorities to be considered when making awards under the Bonus Plan: (i) continue to control all operating, capital and general and administrative costs, (ii) invest in our businesses primarily within existing cash flow, (iii) continue priority emphasis and strong performance relative to a safe workplace, (iv) reinforce business philosophy and mindset that promotes environmental and regulatory compliance, (v) continue to tightly manage the Downstream Business inventory exposure, (vi) execute on major capital and development projects, such as finalizing negotiations, completing projects on time and on budget, and optimizing economics and capital funding, (vii) pursue selected opportunities, including new shale play gathering and processing build-outs, other fee-based capex projects and potential purchases of strategic assets, (viii) pursue commercial and financial approaches to achieve maximum value and manage risks, and (ix) execute on all business dimensions, including the financial business plan. The Compensation Committee also established the following overall threshold, target and maximum levels for the Company s bonus pool: 50% of the cash bonus pool for the threshold level; 100% for the target level and 200% for the maximum level. The CEO and the Compensation Committee relied on compensation consultants and market data from peer company and broader industry compensation practices to establish the threshold, target and maximum percentage levels, which are generally consistent with peer company and broader energy compensation practices. The cash bonus pool target amount is determined by summing, on an employee by employee basis, the product of base salaries and market-based target bonus percentages. The CEO and the Compensation Committee arrive at the total amount of cash to be allocated to the cash bonus pool by multiplying percentage of target awarded by the Compensation Committee by the total target cash bonus pool. The funding of the cash bonus pool and the payment of individual cash bonuses to executive management, including our named executive officers, are subject to the sole discretion of the Compensation Committee.

In February 2011, the Compensation Committee approved a cash bonus pool equal to 180% of the target level for the employee group, including our named executive officers, under the Bonus Plan for performance during 2010 in recognition of outstanding efforts and organizational performance. The Compensation Committee determined to pay these above target level bonuses because it considered overall performance, including organizational performance, to have substantially exceeded expectations in 2010 based on the nine key business priorities it established for 2010. The Compensation Committee considered or subjectively evaluated (rather than measured) organizational performance by reviewing the apparent overall performance of our personnel with respect to the initial and subsequent business priorities relative to both the overall and management-specific performance expectations of the Compensation

Committee, each on an absolute level and relative to the Compensation Committee s sense of peer performance. This subjective assessment that performance substantially exceeded expectations was based on a qualitative evaluation rather than a mechanical, quantitative determination of results across each of the key business priorities. Aspects of performance important to this qualitative determination included (i) continued focus on cost control, including the completion of capital projects typically below budget, (ii) strong success investing in our businesses, (iii) proactive efforts to enhance safety and compliance with environmental and regulatory requirements, (iv) disciplined management of NGL inventory levels and related commodity price exposure, (v) success on transactions including project economics and project management, (vi) pursuing multiple opportunities to expand our downstream position and to add fee-based business, (vii) innovation in new gathering and processing commercial transactions and in securing significant volume guarantees in downstream contracting, (viii) exceeding the financial business plan, (ix) resolution of certain significant disputes and (x) completion of the dropdown of our businesses to the Partnership and clarification of strategic direction for our investors. This subjective evaluation that performance had substantially exceeded expectations occurred with the background and ongoing context of detailed board and committee refinements of the 2010 business priorities both before the beginning of and during the year, continued board and committee discussion and active dialogue with management about priorities in subsequent board and committee meetings, and further board and committee discussion of performance relative to expectations following the end of 2010. The extensive business and board experience of the Compensation Committee and of our board of directors provide the perspective to make this subjective assessment in a qualitative manner and to evaluate management performance overall and the performance of the executive officers. The executive officers received the following bonus awards, which are equivalent to the same average percentage of target as the Company bonus pool:

Rene R. Joyce	$ 855,000
Jeffrey J. McParland	489,600
Joe Bob Perkins	593,280
James W. Whalen	593,280
Michael A. Heim	531,360
Matthew J. Meloy	224,100

In addition to the cash bonus awards approved under the Bonus Plan, in February 2011, the Compensation Committee approved an aggregate cash bonus pool of $1.5 million for our executive officers and two other employees in recognition of their role in extraordinary execution of the business priorities, completion of drop downs to the Partnership and clarification of our strategic direction in 2010.

Long-term Cash Incentives. In January 2008 and 2009, we granted our executive officers cash-settled performance unit awards linked to the performance of the Partnership s common units that will vest in June of 2011 and 2012, with the amounts vesting under such awards dependent on the Partnership s performance compared to a peer-group consisting of the Partnership and 12 other publicly traded partnerships. The peer group companies for 2008 and 2009 were Energy Transfer Partners, ONEOK Partners, Copano, DCP Midstream, Regency Energy Partners, Plains All American Pipeline, MarkWest Energy Partners, Williams Energy Partners, Magellan Midstream, Martin Midstream, Enbridge Energy Partners, Crosstex and Targa Resources Partners LP. The Compensation Committee has the ability to modify the peer-group in the event a peer company is no longer determined to be one of the Partnership s peers. The cash settlement value of these performance unit awards will be the sum of the value of an equivalent Partnership common unit at the time of vesting plus associated distributions over the three year period multiplied by a performance vesting percentage which may be zero or range from 50% to 100%. This cash settlement value may be higher or lower than the Partnership common unit price at the time of the grant. If the Partnership s performance equals or exceeds the performance for the median of the group, 100% of the award will vest. If the Partnership ranks tenth in the group, 50% of the award will vest, between tenth and seventh, 50% to 100% will vest based on an interpolated basis, and for a performance ranking lower than tenth, no amounts will vest. In January 2008, our named executive officers, who are also executive officers of the General Partner, received awards of performance units as follows:

4,000 performance units to Mr. Joyce, 2,700 performance units to Mr. McParland, 3,500 performance units to

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Mr. Perkins, 3,500 performance units to Mr. Whalen and 3,500 performance units to Mr. Heim. In August 2008, Mr. Meloy received an award of 1,500 performance units. In January 2009, the named executive officers received awards of performance units as follows: 34,000 performance units to Mr. Joyce, 15,500 performance units to Mr. McParland, 20,800 performance units to Mr. Perkins and 20,800 performance units to Mr. Heim. In August 2009, Mr. Meloy received an award of 7,500 performance units.

In addition to the January 2009 grants, in December 2009, our executive officers were awarded performance units under our long-term incentive plan for the 2010 compensation cycle that will vest in June 2013 as follows: 18,025 performance units to Mr. Joyce, 13,464 performance units to Mr. Whalen, 9,350 performance units to Mr. McParland, 13,860 performance units to Mr. Perkins and 9,894 performance units to Mr. Heim. In August 2010, Mr. Meloy received an award of 4,000 performance units. The cash settlement value of these performance unit awards will be the sum of the value of an equivalent Partnership common unit at the time of vesting plus associated distributions over the three year period multiplied by a performance vesting percentage which may be zero or range from 25% to 150%. This cash settlement value may be higher or lower than the Partnership common unit price at the time of the grant. If the Partnership s performance equals or exceeds the performance for the 25th percentile of the group but is less than or equal to the 50th percentile of the group, then 25% to 100% of the award will vest. If the Partnership s performance equals or exceeds the performance for the 50th percentile of the group but is less than or equal to the 75th percentile of the group, then 100% to 150% of the award will vest. The vesting between the 25th percentile and the 50th percentile will be done on an interpolated basis between 25% and 100% and the vesting between the 50th percentile and 75th percentile will be done on an interpolated basis between 100% and 150%. If the Partnership s performance is above the performance of the 75th percentile of the group, the performance percentage will be 150% of the award. If the Partnership s performance is below the performance of the 25th percentile of the group, the performance percentage will be zero. The performance period for these performance unit awards began on June 30, 2010 and ends on the third anniversary of such date.

Set forth below is the performance for the median of the peer group for each of the 2008, 2009 and 2010 grants and a comparison of the Partnership s performance to the peer group as of December 31, 2010:

	Performance[(1)]		
Grant	**Peer Group Median**	**Partnership**	**Partnership Position[(2)]**
2008	43.5%	74.6%	1 of 13
2009 (January grants)	59.4%	100.6%	1 of 13
2009 (December grants)	16.8%	34.3%	100th percentile
2010	16.8%	34.3%	100th percentile

(1) Total return measured by (i) subtracting the average closing price per share/unit for the first ten trading days of the performance period (the Beginning Price) from the sum of (a) the average closing price per share/unit for the last ten trading days ending on the date that is 15 days prior to the end of the performance period plus (b) the aggregate amount of dividends/distributions paid with respect to a share/unit during such period (the result being referred to as the Value Increase) and (ii) dividing the Value Increase by the Beginning Price. The performance period for the 2008 and January 2009 awards begins on June 30, 2008 and June 30, 2009 while the December 2009 and 2010 awards begins on June 30, 2010, and all awards end on the third anniversary of such dates.

(2) The Partnership s position for the December 2009 and the 2010 grants is measured by the Partnership s placement in a particular quartile rather than its specific rank against the peer group.

Health and Welfare Benefits. For 2010, our named executive officers participated in our health and welfare benefit programs, including medical, health, life insurance, dental coverage and disability insurance on the same basis as all of our other employees.

Perquisites. Consistent with our compensation philosophy, we did not pay for perquisites for any of our named executive officers during 2010, other than parking subsidies.

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Changes for 2011

Base Salary. The 2010 increase in base pay for the key employees closed only approximately one-half of the gap in executive compensation highlighted by the review referred to above under The Role of Peer Groups and Benchmarking. In order to begin closing this remaining gap in compensation, the Compensation Committee authorized, and executive management will implement, the following increased base salaries for our named executive officers effective April 1, 2011:

Rene R. Joyce	$ 547,000
Jeffrey J. McParland	389,000
Joe Bob Perkins	468,000
James W. Whalen	468,000
Michael A. Heim	415,000
Matthew J. Meloy	235,000

With this move in base salaries, the gap will be reduced by approximately one-half.

Annual Cash Incentives. In light of recent economic and financial events, Senior Management developed and proposed a set of strategic priorities to the Compensation Committee. In February 2011, the Compensation Committee approved our 2011 Annual Incentive Compensation Plan (the 2011 Bonus Plan), the cash bonus plan for performance during 2011, and established the following eight key business priorities: (i) continue to control all operating, capital and general and administrative costs, (ii) invest in our businesses, (iii) continue priority emphasis and strong performance relative to a safe workplace, (iv) reinforce business philosophy and mindset that promotes compliance with all aspects of our business including environmental and regulatory compliance, (v) continue to manage tightly credit, inventory, interest rate and commodity price exposures, (vi) execute on major capital and development projects, such as finalizing negotiations, completing projects on time and on budget, and optimizing economics and capital funding, (vii) pursue selected growth opportunities, including new gathering and processing build-outs leveraging our logistics platform for development projects, other fee-based capex projects and potential purchases of strategic assets and (viii) execute on all business dimensions to maximize value and manage risks. The Compensation Committee also established the following overall threshold, target and maximum levels for the Company s bonus pool: 50% of the cash bonus pool for the threshold level; 100% for the target level and 200% for the maximum level. As with the Bonus Plan, funding of the cash bonus pool and the payment of individual cash bonuses to executive management, including our named executive officers, are subject to the sole discretion of the Compensation Committee. The market-based base salary bonus percentages for the named executive officers used in determining the annual cash incentives were increased in connection with the increases in base salary in 2010.

Long-term Incentives. On February 14, 2011, our named executive officers were awarded restricted common stock of the Company under our stock incentive plan for the 2011 compensation cycle that will vest in three years from the grant date as follows: 7,690 shares to Mr. Joyce, 4,250 shares to Mr. Perkins, 4,250 shares to Mr. Whalen, 3,770 shares to Mr. Heim, 3,540 shares to Mr. McParland, and 1,260 shares to Mr. Meloy.

On February 17, 2011, our named executive officers were awarded equity-settled performance units under the Partnership s long-term incentive plan for the 2011 compensation cycle that will vest in June 2014 as follows: 21,110 performance units to Mr. Joyce, 11,690 performance units to Mr. Perkins, 11,690 performance units to Mr. Whalen, 10,360 performance units to Mr. Heim, 9,710 performance units to Mr. McParland, and 3,470 performance units to Mr. Meloy. The settlement value of these performance unit awards will be determined using the formula adopted for the performance unit awards granted in December 2009.

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Executive Compensation

The following Summary Compensation Table sets forth the compensation of our named executive officers for 2010, 2009 and 2008. Additional details regarding the applicable elements of compensation in the Summary Compensation Table are provided in the footnotes following the table.

Summary Compensation Table for 2010

Name	Year	Salary	Bonus[2]	Stock Awards ($)[3]	Non-Equity Incentive Plan Compensation[4]	All Other Compensation[5]	Total Compensation
Rene R. Joyce	2010	$ 410,000	$ 265,067	$ 5,358,408	$ 855,000	$ 22,410	$ 6,910,885
Chief Executive Officer	2009	337,500		1,398,946	510,000	20,187	2,266,633
	2008	322,500		148,400	247,500	19,205	737,605
Jeffrey J. McParland[1]	2010	305,500	189,732	3,162,324	489,600	20,904	4,168,060
President Finance and	2009	265,000		683,450	400,500	20,061	1,369,011
Administration	2008	253,000		110,170	194,250	19,031	566,451
Joe Bob Perkins	2010	361,250	229,911	3,831,960	593,280	20,448	5,036,849
President	2009	303,750		970,109	459,000	20,129	1,752,988
	2008	290,250		129,850	222,750	19,124	661,974
James W. Whalen[1]	2010	356,750		3,831,960	593,280	22,328	4,804,318
Executive Chairman of the	2009	297,000		543,150	445,500	19,936	1,305,586
Board	2008	290,250		129,850	222,750	18,871	661,721
Michael A. Heim	2010	328,000	937,915	2,699,620	531,360	21,776	4,518,671
Executive Vice President	2009	281,000		810,117	424,500	20,089	1,535,706
and Chief Operating Officer	2008	268,750		129,850	206,250	19,071	623,921
Matthew J. Meloy Senior Vice President and Chief Financial Officer	2010	195,625		493,350	224,100	19,740	932,815

(1) Mr. McParland became President, Finance and Administration in December 2010 and previously served as Executive Vice President and Chief Financial Officer. Mr. Whalen became Executive Chairman of the Board of Directors in December 2010 and previously served as President, Finance and Administration. Mr. Meloy was promoted to Senior Vice President and Chief Financial Officer in December 2010. Prior to his promotion, Mr. Meloy served as Vice President Finance and Treasurer.

(2) Represents discretionary cash bonuses paid to the named executive officers in recognition of the executive team s role in extraordinary execution of the business priorities, completion of drop downs to the Partnership and

clarification of our strategic direction in 2010. $732,000 of the amount reported for Mr. Heim represents a cash bonus paid in lieu of equity in connection with the IPO. Please see Executive Compensation Compensation Discussion and Analysis Application of Compensation Elements Bonus Stock Awards and Executive Compensation Compensation Discussion and Analysis Application of Compensation Elements Annual Cash Incentives.

(3) The restricted stock awards in 2010 to executive officers were made based upon the recommendation of the compensation consultant using market-based precedent and market-based amounts to provide a one-time retention and incentive award in connection with our transition from a private to a public company. Please see Executive Compensation Compensation Discussion and Analysis Application of Compensation Elements. Amounts represent the aggregate grant date fair value of awards computed in accordance with FASB ASC Topic 718. Assumptions used in the calculation of these amounts are included in Note 24 to our Consolidated Financial Statements beginning on page F-1. Detailed information about the amount recognized for specific awards is reported in the table under Grants of Plan-Based Awards below. The grant date fair value of a common stock award approved on December 6, 2010 and granted on December 10, 2010, assuming vesting will occur, is $22.00.

(4) Amounts represent awards granted pursuant to our Bonus Plan. See the narrative to the section titled Grants of Plan-Based Awards below for further information regarding these awards.

(5) For 2010 All Other Compensation includes the (i) aggregate value of matching and non-matching contributions to our 401(k) plan and (ii) the dollar value of life insurance coverage provided by the Company.

Name	401(k) and Profit Sharing Plan	Dollar Value of Life Insurance	Total
Rene R. Joyce	$ 19,600	$ 2,810	$ 22,410
Jeffrey J. McParland	19,600	1,304	20,904
Joe Bob Perkins	19,600	848	20,448
James W. Whalen	19,600	2,728	22,328
Michael A. Heim	19,600	2,176	21,776
Matthew J. Meloy	19,600	140	19,740

Grants of Plan-Based Awards

The following table and the footnotes thereto provide information regarding grants of plan-based equity and non-equity awards made to the named executive officers during 2010:

Grants of Plan Based Awards for 2010

Name	Grant Date	Approval Date	Estimated Possible Payouts Under Non-Equity Incentive Plan Awards(1) Threshold	Target	2X Target	All Other Stock Awards: Number of Shares of Stocks or Units(2)	Grant Date Fair Value of Stock and Option Awards(3)
Mr. Joyce	N/A	N/A	$ 237,500	$ 475,000	$ 950,000		
	12/10/10	12/06/10				121,125(4)	$ 2,644,750
	12/10/10	12/06/10				122,439(5)	2,693,658
Mr. McParland	N/A	N/A	136,000	272,000	544,000		
	12/10/10	12/06/10				56,100(4)	1,234,200
	12/10/10	12/06/10				87,642(5)	1,928,124
Mr. Perkins	N/A	N/A	164,800	329,600	659,200		
	12/10/10	12/06/10				67,980(4)	1,495,560
	12/10/10	12/06/10				106,200(5)	2,336,400
Mr. Whalen	N/A	N/A	164,800	329,600	659,200		
	12/10/10	12/06/10				67,980(4)	1,495,560
	12/10/10	12/06/10				106,200(5)	2,336,400
Mr. Heim	N/A	N/A	147,600	295,200	590,400		
	12/10/10	12/06/10				60,885(4)	1,339,470
	12/10/10	12/06/10				61,825(5)	1,360,150
Mr. Meloy	N/A	N/A	41,500	83,000	166,000	22,425(4)	493,350
	12/10/10	12/06/10					

(1) These awards were granted under the Bonus Plan. At the time the Bonus Plan was adopted, the estimated future payouts in the above table under the heading Estimated Possible Payouts Under Non-Equity Incentive Plan Awards represented the portion of the cash bonus pool available for awards to the named executive officers under the Bonus Plan based on the three performance levels. In February 2011, the Compensation Committee approved a bonus award for the named executive officers equal to 1.8x of the target. See Executive Compensation Compensation Discussion and Analysis Application of Compensation Elements Annual Cash Incentives.

(2) These common stock awards were granted under our 2010 Incentive Plan. The stock awards to executive officers were made based upon the recommendation of the compensation consultant using market-based precedent and market-based amounts to provide a one-time retention and incentive award in connection with our transition from a private to a public company.

(3) The dollar amounts shown for the common stock awards approved on December 6, 2010 and granted on December 10, 2010 are determined by multiplying the shares reported in the table by $22.00 (the grant date fair value of awards computed in accordance with FASB ASC Topic 718).

(4) Restricted stock awards.

(5) Bonus stock awards.

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

A discussion of 2010 salaries, bonuses, incentive plans and awards is included in Executive Compensation Compensation Discussion and Analysis.

2010 Stock Incentive Plan

Restricted Stock Awards. Subject to the terms of the applicable restricted stock agreement, restricted stock granted under the 2010 Incentive Plan during 2010 has a vesting period of two years from the date of grant (with respect to 60% of the shares awarded) and three years from the date of grant (with respect to 40% of the shares awarded). The named executive officers have all of the rights of a stockholder of the Company with respect to the restricted stock granted in 2010 including, without limitation, voting rights. The named executive officers do not have the right to receive any dividends or other distributions, including any special or extraordinary dividends or distributions, with respect to the restricted stock granted in 2010 unless and until the restricted stock vests. Dividends on unvested restricted stock are credited to an unfunded account maintained by the Company. These credited dividends are paid to the employee when the shares of restricted stock vest. In the event all or any portion of the restricted stock granted in 2010 fails to vest, such restricted stock and dividends will be forfeited to us.

Bonus Stock Awards. Bonus stock awarded in 2010 is not subject to any vesting or forfeiture provisions.

Please see Executive Compensation Compensation Discussion and Analysis Elements of Compensation for Named Executive Officers New Incentive Plan and Executive Compensation Compensation Discussion and Analysis Application of Compensation Elements Equity Ownership for a detailed discussion of the grants of restricted stock and bonus stock.

Outstanding Equity Awards at 2010 Fiscal Year-End

The following table and the footnotes related thereto provide information regarding each stock option and other equity-based awards outstanding as of December 31, 2010 for each of our named executive officers.

Outstanding Equity Awards at 2010 Fiscal Year End

	Stock Awards			
	Number of Shares of	Market Value of Shares of Stock That Have Not	Equity Incentive Plan Awards: Number of Unearned Performance Units That Have Not	Equity Incentive Plan Awards: Market or Payout Value of Unearned Performance Units That Have Not

Name	Stock That Have Not Vested[1]	Vested[2]	Vested[3]	Vested [4]
Rene R. Joyce	121,125	$ 3,247,361	56,025	$ 2,263,953
Jeffrey J. McParland	56,100	1,504,041	27,550	1,113,254
Joe Bob Perkins	67,980	1,822,544	38,160	1,542,127
James W. Whalen	67,980	1,822,544	16,964	686,185
Michael A. Heim	60,885	1,632,327	34,194	1,381,504
Matthew J. Meloy	22,425	601,214	13,000	525,233

(1) Represents shares of our restricted common stock awarded on December 10, 2010. These shares vest as follows: 60% on December 10, 2012 and 40% on December 10, 2013.

(2) The dollar amounts shown are determined by multiplying the number of shares of common stock reported in the table by the sum of the closing price of a share of common stock on December 31, 2010 ($26.81).

(3) Represents the number of performance units awarded on January 17, 2008, January 22, 2009 and December 3, 2009 under our long-term incentive plan. With respect to Mr. Meloy, the performance units were granted on October 1, 2008, August 4, 2009 and August 2, 2010. These awards vest in June 2011, June 2012, and June 2013, based on the Partnership s performance over the applicable period measured against a peer group of companies. These awards are discussed in more detail under the heading Executive Compensation Compensation Discussion and Analysis Application of Compensation Elements Long-Term Cash Incentives.

(4) The dollar amounts shown are determined by multiplying the number of performance units reported in the table by the sum of the closing price of a common unit of the Partnership on December 31, 2010 ($33.96) and the related distribution equivalent rights for each award and assume full payout under the awards at the time of vesting.

Option Exercises and Stock Vested in 2010

The following table provides the amount realized during 2010 by each named executive officer upon the exercise of options and upon the vesting of our restricted common stock and performance units.

Option Exercises and Stock Vested for 2010

	Option Awards		**Stock Awards**	
	Number of Shares Acquired on Exercise[1]	**Value Realized on Exercise**	**Number of Shares Acquired on Vesting**[2]	**Value Realized on Vesting**[3]
Rene R. Joyce	155,447	$ 459,957	15,000	$ 499,406
Jeffrey J. McParland	108,556	324,555	8,200	273,009
Joe Bob Perkins	117,241	350,520	10,800	359,573
James W. Whalen	45,158	135,012	10,800	359,573
Michael A. Heim	127,946	377,735	10,000	332,938
Matthew J. Meloy	15,942	43,162	3,000	99,881

(1) At the time of exercise of the stock options, the common stock acquired upon exercise had a value of $3.46 per share. This value was determined by an independent consultant pursuant to a valuation of our common stock dated June 2, 2010.

(2) Represents performance units granted in February 2007 that vested in August 2010 and were settled by cash payment.

(3) Computed by multiplying the number of performance units by the value of an equivalent Partnership common unit at the time of vesting and adding associated distributions over the vesting period.

Change in Control and Termination Benefits

2010 Incentive Plan.

If a Change in Control (as defined below) occurs and the named executive officer has remained continuously employed by us from the date of grant to the date upon which such Change in Control occurs, then the restricted stock granted to him under our form of restricted stock agreement (the Stock Agreement) and related dividends then credited to him will fully vest on the date upon which such Change in Control occurs.

Restricted stock granted to a named executive officer under the Stock Agreement and related dividends then credited to him will fully vest if his employment is terminated by reason of death or a Disability (as defined below). If a named executive officer s employment with us is terminated for any reason other than death or Disability, then his unvested restricted stock is forfeited to us for no consideration.

The following terms have the specified meanings for purposes of the 2010 Incentive Plan and Stock Agreement:

Affiliate means any corporation, partnership (including the Partnership), limited liability company or partnership, association, trust, or other organization which, directly or indirectly, controls, is controlled by, or is under common control with, the Company. For purposes of the preceding sentence, control (including, with correlative meanings, the terms controlled by and under common control with), as used with respect to any entity or organization, shall mean the possession, directly or indirectly, of the power (i) to vote more than 50% of the securities having ordinary voting power for the election of directors of the controlled entity or organization or (ii) to direct or cause the direction of the management and policies of the controlled entity or organization, whether through the ownership of voting securities or by contract or otherwise.

Change in Control means the occurrence of one of the following events: (i) any Person, including a group as contemplated by section 13(d)(3) of the Exchange Act (other than Warburg Pincus LLC or any other Affiliate), acquires or gains ownership or control (including, without limitation, the power to vote), by way of merger, consolidation, recapitalization, reorganization or otherwise, of more than 50% of the outstanding shares of the Company s voting stock (based upon voting power) or more than 50% of the combined voting power of the equity interests in the Partnership or the general partner of the Partnership; (ii) the completion of a liquidation or dissolution of the Company or the approval by the limited partners of the Partnership, in one or a series of transactions, of a plan of complete liquidation of the Partnership; (iii) the sale or other disposition by the Company of all or substantially all of its assets in or more transactions to any Person other than Warburg Pincus LLC or any other Affiliate; (iv) the sale or disposition by either the Partnership or the general partner of the Partnership of all or substantially all of its assets in one or more transactions to any Person other than to Warburg Pincus LLC, Targa Resources GP LLC, or any other Affiliate; (v) a transaction resulting in a Person other than Targa Resources GP LLC or an Affiliate being the general partner of the Partnership; or (vi) as a result of or in connection with a contested election of directors, the persons who were directors of the Company before such election shall cease to constitute a majority of the Company s board of directors. Notwithstanding the foregoing, with respect to an award under the 2010 Incentive Plan that is subject to section 409A of the Internal Revenue Code of 1986, as amended, and with respect to which a Change in Control will accelerate payment, Change in Control shall mean a change of control event as defined in the regulations and guidance issued under section 409A of the Code.

Disability means a disability that entitles the named executive officer to disability benefits under our long-term disability plan.

Person means an individual or a corporation, limited liability company, partnership, joint venture, trust, unincorporated organization, association, government agency or political subdivision thereof, or other entity.

The following table reflects payments that would have been made to each of the named executive officers under the 2010 Incentive Plan and related agreements in the event there was a Change in Control or their employment was terminated, each as of December 31, 2010.

Name	Change of Control[1]	Termination for Death or Disability[1]
Rene R. Joyce	$ 3,247,361	$ 3,247,361
Jeffrey J. McParland	1,504,041	1,504,041
Joe Bob Perkins	1,822,544	1,822,544
James W. Whalen	1,822,544	1,822,544
Michael A. Heim	1,632,327	1,632,327
Matthew J. Meloy	601,214	601,214

(1) Amounts relate to the unvested shares of restricted stock of the Company granted on December 10, 2010.

Long-Term Incentive Plan.

If a Change of Control (as defined below) occurs during the performance period established for the performance units and related distribution equivalent rights granted to a named executive officer under our form of Performance Unit Grant Agreement (a Performance Unit Agreement), the performance units and related distribution equivalent rights then credited to a named executive officer will be cancelled and the named executive officer will be paid an amount of cash equal to the sum of (i) the product of (a) the Fair Market Value (as defined below) of a common unit of the Partnership multiplied by (b) the number of performance units granted to the named executive officer, plus (ii) the amount of distribution equivalent rights then credited to the named executive officer, if any.

Performance units and the related distribution equivalent rights granted to a named executive officer under a Performance Unit Agreement will be automatically forfeited without payment upon the termination of his employment with us and our affiliates, except that: if his employment is terminated by reason of his death, a disability that entitles him to disability benefits under our long-term disability plan or by us other than for Cause (as defined below), he will be vested in his performance units that he is otherwise qualified to receive payment for based on achievement of the performance goal at the end of the Performance Period.

The following terms have the specified meanings for purposes of our long-term incentive plan:

> *Change of Control* means (i) any person or group within the meaning of those terms as used in Sections 13(d) and 14(d)(2) of the Exchange Act, other than an affiliate of us, becoming the beneficial owner, by way of merger, consolidation, recapitalization, reorganization or otherwise, of 50% or more of the combined voting power of the equity interests in the Partnership or its general partner, (ii) the limited partners of the Partnership approving, in one or a series of transactions, a plan of complete liquidation of the Partnership, (iii) the sale or other disposition by either the Partnership or the General Partner of all or substantially all of its assets in one or more transactions to any person other than the General Partner or one of the General Partner s affiliates or (iv) a transaction resulting in a person other than the Partnership s general partner or one of such general partner s affiliates being the general partner of the Partnership. With respect to an award subject to Section 409A of the Code, Change of Control will mean a change of control event as defined in the regulations and guidance issued under Section 409A of the Code.

Fair Market Value means the closing sales price of a common unit of the Partnership on the principal national securities exchange or other market in which trading in such common units occurs on the applicable date (or if there is not trading in the common units on such date, on the next preceding date on which there was trading) as reported in The Wall Street Journal (or other reporting service approved by the Compensation Committee). In the event the common units are

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not traded on a national securities exchange or other market at the time a determination of fair market value is required to be made, the determination of fair market value shall be made in good faith by the Compensation Committee.

Cause means (i) failure to perform assigned duties and responsibilities, (ii) engaging in conduct which is injurious (monetarily of otherwise) to us or our affiliates, (iii) breach of any corporate policy or code of conduct established by us or our affiliates or breach of any agreement between the named executive officer and us or our affiliates or (iv) conviction of a misdemeanor involving moral turpitude or a felony. If the named executive officer is a party to an agreement with us or our affiliates in which this term is defined, then that definition will apply for purposes of our long-term incentive plan and the Performance Unit Agreement.

The following table reflects payments that would have been made to each of the named executive officers under our long-term incentive plan and related agreements in the event there was a Change of Control or their employment was terminated, each as of December 31, 2010.

Name	Change of Control	Termination for Death or Disability
Rene R. Joyce	$ 2,049,196(1)	$ 2,049,196(1)
Jeffrey J. McParland	1,008,188(2)	1,008,188(2)
Joe Bob Perkins	1,394,083(3)	1,394,083(3)
James W. Whalen	608,637(4)	608,637(4)
Michael A. Heim	1,255,173(5)	1,255,173(5)
Matthew J. Meloy	477,053(6)	477,053(6)