Targa Resources Corp.
Form 424B1
December 07, 2010

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Registration No. 333-169277

PROSPECTUS

16,375,000 Shares

Targa Resources Corp.
Common Stock

This is the initial public offering of the common stock of Targa Resources Corp. The selling stockholders identified in this prospectus, including a member of our senior management, are offering 16,375,000 shares of our common stock. We will not receive any proceeds from the sale of shares by the selling stockholders. No public market currently exists for our common stock.

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.

We have been approved to list our common stock on the New York Stock Exchange under the symbol TRGP.

Investing in our common stock involves risks. See Risk Factors beginning on page 23 of this prospectus.

	Per Share	Total
Price to the public	$ 22.00	$ 360,250,000
Underwriting discounts and commissions[1]	$ 1.21	$ 19,813,750
Proceeds to the selling stockholders	$ 20.79	$ 340,436,250

(1) Excludes a structuring fee equal to 0.25% of the gross proceeds of this offering, or approximately $900,625, payable by Targa Resources Corp. to Barclays Capital Inc.

Certain of the selling stockholders have granted the underwriters a 30-day option to purchase up to an additional 2,456,250 shares of common stock on the same terms and conditions as set forth above if the underwriters sell more than 16,375,000 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 December 10, 2010.

Barclays Capital **Morgan Stanley** **BofA Merrill Lynch**

Citi **Deutsche Bank Securities**

Credit Suisse **J.P. Morgan** **Wells Fargo Securities**

Raymond James	**RBC Capital Markets**	**UBS Investment Bank**

Baird	**ING**

Prospectus dated December 6, 2010

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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.

Until December 31, 2010, all dealers that buy, sell or trade our common stock, whether or not participating in this offering, may be required to deliver a prospectus. This requirement is in addition to the dealers obligation to deliver a prospectus when acting as underwriters and with respect to their unsold allotments or subscriptions.

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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 23 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, the Company and similar terms refer either to Targa Resources Corp., formerly Targa Resources Investments Inc., 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, and (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.

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 and storing, fractionating, treating, transporting and selling natural gas liquids, or NGLs, and NGL products. 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 of the Partnership; and
- 11,645,659 of the 75,545,409 outstanding common units of the Partnership, representing a 15.1% limited partnership interest in the Partnership.

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

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 IDRs and general partner interests entitle us to receive:

2% of all cash distributed in a quarter until $0.3881 has been distributed in respect of each common unit of the Partnership for that quarter;

15% 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;

25% 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

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50% 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 November 4, 2010, the Partnership announced that management plans to recommend to the General Partner s board of directors a $0.04 increase in the annualized cash distribution rate to $2.19 per common unit for the fourth quarter of 2010 distribution. Based on a $2.19 annualized rate, a quarterly distribution by the Partnership of $0.5475 per common unit will result in a quarterly distribution 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 a quarterly distribution to us of $6.3 million, or $25.2 million on an annualized basis, in respect of our 2% general partner interest and IDRs for total quarterly distributions of $12.7 million, or $50.7 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. Based on the current distribution policy of the Partnership, we plan to pay an initial quarterly dividend of $0.2575 per share of our common stock, or $1.03 per share on an annualized basis, for a total quarterly dividend of approximately $10.9 million, or $43.6 million on an annualized basis, per our dividend policy, which we will adopt prior to the conclusion of this offering. 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 44.7 million additional common units by the Partnership over time to finance acquisitions and capital improvements. Over the same period, the quarterly distributions declared and to be recommended by the Partnership in respect of our 2% general partner interest and IDRs increased approximately 3,050% from $0.2 million to $6.3 million.

Quarterly Cash Distributions by the Partnership[(1)]

(1) Represents historical 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:

- the Partnership has a total of 75,545,409 common units outstanding; and
- we own (i) a 2% general partner interest in the Partnership, (ii) the IDRs and (iii) 11,645,659 common units of the Partnership.

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The graph below also illustrates the impact on us of the Partnership raising or lowering its per common unit distribution from the fourth quarter quarterly distribution of $0.5475 per common unit, or $2.19 per common unit on an annualized basis, that management plans to recommend to the General Partner s board of directors. 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 the issuance 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[(1)]

(1) For the fourth quarter of 2010, management plans to recommend a quarterly cash distribution of $0.5475 per common unit, or $2.19 per common unit on an annualized basis.

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.

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 and storing, fractionating, treating, transporting and selling NGLs and NGL products. 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) NGL 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 NGL logistics and marketing division, or Downstream Business, has net NGL fractionation capacity of approximately 314 MBbl/d, 48 owned and operated storage wells with a net storage capacity of approximately 67 MMBbl, and 15 storage, marine and transport terminals with above ground NGL storage capacity of approximately 825 MBbl.

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, and over the same period, the Partnership has invested approximately $196 million in growth capital expenditures. 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 December 3, 2010, the Partnership has an equity market capitalization of $2.3 billion. As of September 30, 2010, the Partnership had total assets of $3.1 billion.

Recent Transactions

On August 25, 2010, the Partnership acquired from us a 63% ownership interest in Versado Gas Processors, L.L.C. (Versado), a joint venture in which Chevron U.S.A. Inc. owns the remaining 37% interest, for a purchase price of $247.2 million. Versado owns a natural gas gathering and processing business consisting of the Eunice, Monument and Saunders gathering and processing systems, including treating operations, processing plants and related assets (collectively, the Versado System). The Versado System includes three refrigerated cryogenic processing plants and approximately 3,200 miles of combined gathering pipelines in Southeast New Mexico and West Texas and is primarily conducted under percent of proceeds arrangements. During 2009, the Versado System processed an average of approximately 198.8 MMcf/d of natural gas and produced an average of approximately 22.2 MBbl/d of NGLs. In the first nine months of 2010, the Versado System processed an average of approximately 180.5 MMcf/d of natural gas and produced an average of approximately 20.4 MBbl/d of NGLs.

On September 28, 2010, the Partnership acquired from us a 77% ownership interest in Venice Energy Services Company, L.L.C. (VESCO), a joint venture in which Enterprise Gas Processing, LLC and Oneok Vesco Holdings, L.L.C. own the remaining ownership interests, for a purchase price of $175.6 million. 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, the VESCO System). The VESCO System captures volumes from the Gulf of Mexico shelf and deepwater. For the year ended December 31, 2009 and for the nine months ended September 30, 2010, VESCO processed 363 MMcf/d and 423 MMcf/d of natural gas, respectively.

On October 8, 2010, the Partnership declared a quarterly cash distribution of $0.5375 per common unit, or $2.15 per common unit on an annualized basis for the third quarter of 2010, payable on November 12, 2010 to holders of record on October 18, 2010.

On November 4, 2010, the Partnership announced that management plans to recommend to the General Partner s board of directors a $0.04 increase in the annualized cash distribution rate to $2.19 per common unit for the fourth quarter of 2010 distribution.

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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 and 2012 that are supported by long-term, fee-based contracts. These projects include:

Cedar Bayou Fractionator expansion project: The Partnership is currently constructing approximately 78 MBbl/d of additional fractionation capacity at the Partnership s 88% owned Cedar Bayou Fractionator (CBF) in Mont Belvieu for an 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.

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 has successfully completed both large and small organic growth projects that are associated with its existing assets and expects to continue to do so in the future. These projects have involved growth capital expenditures of approximately $245 million since 2005 and include an LSNG project, operations improvements and efficiency enhancements, opportunistic commercial development activities, and other enhancements.

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, take-or-pay contracts for existing capacity and support the construction of new fractionation capacity, such as the

Partnership s CBF and GCF expansion projects. The Partnership is continuing to see rates for fractionation services increase. The

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higher volumes of fractionated NGLs should also result in increased demand for other related fee-based services provided by the Partnership s Downstream Business.

Natural gas shale opportunities. The Partnership is actively pursuing natural gas gathering and processing and NGL fractionation opportunities associated with many of the active, liquids rich natural gas shale plays, such as certain regions of the Marcellus Shale and Eagle Ford Shale. We believe that the Partnership s leadership position in the NGL Logistics and Marketing business, which includes the Partnership s 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.

Our management team will continue to manage the Partnership s business after this offering, and 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 fractionators of NGLs in the Gulf Coast region.
- 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 s gathering and processing systems and logistics assets consist of high-quality, well maintained assets, resulting in low cost, efficient operations.
- 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.
- 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 Resources Inc., formerly Targa Resources, Inc., 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.

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- 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 acquisitions or investments in new assets on economically acceptable terms or efficiently and effectively integrate new assets, its results of operations and financial condition could be adversely affected.

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

- The Partnership s growth strategy requires access to new capital. Tightened capital markets or increased competition for investment opportunities could impair 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 face, please read Risk Factors.

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Our Structure and Ownership After This Offering

We were formed in October 2005 as a Delaware corporation to become the top-tier holding company for TRI Resources Inc., formerly Targa Resources, Inc. We currently have outstanding a total of (i) 6,409,697 shares of Series B Convertible Participating Preferred Stock par value $0.001 per share (Series B Preferred) held by affiliates of Warburg Pincus LLC (Warburg Pincus), an affiliate of Bank of America and members of management and (ii) 10,228,520 shares of common stock held by members of management and other employees.

All shares of our outstanding Series B Preferred were issued in connection with our formation in October 2005 either by way of purchase or exchange. All shares of our outstanding common stock were issued under our 2005 Stock Incentive Plan as a direct issuance, as a result of option exercises or in exchange for Series B Preferred options.

Following effectiveness of the registration statement of which this prospectus forms a part, (1) we will effect a 1 for 2.03 reverse split of our common stock to reduce the number of shares of our common stock that are currently outstanding and (2) all of our shares of Series B Preferred will automatically convert into shares of common stock, based on (a) the 10 to 1 conversion ratio applicable to the Series B Preferred plus (b) the accreted value per share (which includes accrued and unpaid dividends) of the Series B Preferred divided by the initial public offering price for this offering after deducting underwriting discounts and commissions, in each case after giving effect to the reverse split. We also expect to issue equity awards that total approximately 1.9 million shares of common stock in connection with the offering under a new stock incentive plan. Please see Management Executive Compensation Compensation Discussion and Analysis Changes in Connection with the Completion of this Offering for a description of the new stock incentive plan and the proposed initial grant under the plan.

As described above, the number of shares of common stock to be issued upon conversion of our preferred stock depends on the initial public offering price as well as the accreted value of the preferred stock. For purposes of this prospectus, we have presented all common stock ownership amounts and percentages based on the initial public offering price of $22.00 per share.

The following chart depicts our organizational and ownership structure after giving effect to this offering and the transactions described above. Upon completion of this offering, there will be a total of 42,292,348 common shares outstanding, consisting of the following:

Affiliates of Warburg Pincus will own 16,145,344 shares of common stock, representing a 38.2% ownership interest in us.

An affiliate of Bank of America will own 1,433,795 shares of common stock representing a 3.4% ownership interest in us.

Our employees, including our executive officers, will own approximately 8.3 million shares of common stock, representing a 19.7% ownership interest in us, including the approximately 1.9 million shares of common stock we expect to issue under the new stock incentive plan to be adopted in conjunction with this offering.

Our public stockholders will own 16,375,000 shares of common stock, representing a 38.7% ownership interest in us.

We will indirectly own 100% of the ownership interest in the General Partner, which will own the 2% general partner interest in the Partnership and all of the Partnership s IDRs.

We will indirectly own 11,645,659 of the Partnership s 75,545,409 outstanding common units, representing a 15.1% limited partner interest in the Partnership.

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Our Simplified Organizational Structure
Following this Offering[1]

(1) Gives effect to our corporate reorganization as described above under Our Structure and Ownership After This Offering, the sale of common stock offered by the selling stockholders in this offering, and awards of common stock that will be granted to the directors and executive officers upon the closing of this offering.

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The Offering

Common stock offered to the public	16,375,000 shares
Common stock to be outstanding after this offering	42,292,348 shares[(1)]
Over-allotment option	Certain of the selling stockholders have granted the underwriters a 30-day option to purchase up to an aggregate of 2,456,250 additional shares of our common stock to cover over-allotments.
Use of proceeds	We will not receive any proceeds from this offering.
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	Based on the current distribution policy of the Partnership, our expected federal income tax liabilities, our expected level of other expenses and reserves, we expect that our initial quarterly dividend rate will be $0.2575 per share. We expect to pay a prorated dividend for the portion of the fourth quarter of 2010 that we are public in February 2011. However, we cannot assure you that any dividends will be declared or paid by us. Based on the distributions paid by the Partnership to its unitholders for each of the immediately preceding four quarters, we believe we would have been able to pay the initial quarterly dividend to our shareholders for each of the immediately preceding four quarters. We expect that we will be able to pay the initial quarterly dividend for the three months ending December 31, 2010 and each of the four quarters in the year ending December 31, 2011. 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

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	(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 23 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.
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 6.5% ownership interest in us and is selling 1,324,268 shares of common stock in connection with this offering and will own 1,433,795 shares of our common stock, representing a 3.4% 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 Rule 2720 of the NASD Conduct Rules (which are part of the FINRA Rules). 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.

(1) This number gives effect to the assumed common stock split, to conversion of our outstanding preferred stock into shares of our common stock and to the expected issuance of shares of common stock under our new stock incentive plan, all of which are described under Our Structure and Ownership After This Offering.

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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 will 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 will be 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 will 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.	Under our amended and restated bylaws, we will 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.	Our stockholders do not have preemptive rights.

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	Partnership s Common Units	Our Shares
	Whenever the Partnership issues equity securities to any person other than the General Partner and its 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.	
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 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 will 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.

Summary Historical and Pro Forma 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 selected 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, 2007, 2008 and 2009 and summary historical consolidated balance sheet data as of December 31, 2008 and 2009 have been derived from our audited financial statements, included elsewhere in this prospectus. The summary historical consolidated statement of operations and cash flow data for the nine months ended September 30, 2009 and 2010 and the summary historical consolidated balance sheet data as of September 30, 2010 have been derived from our unaudited financial statements, included elsewhere in this prospectus. The summary historical consolidated balance sheet data as of December 31, 2007 has been derived from our audited financial statements and the summary historical consolidated balance sheet as of September 30, 2009 has been derived from our unaudited financial statements, neither of which is included in this prospectus.

Our summary unaudited pro forma condensed consolidated statement of operations data gives effect to the following transactions which occurred prior to September 30, 2010:

- the September 2010 completion of the sale of our 77% ownership interest in VESCO to the Partnership, including:
  - consideration to us of $175.6 million,
  - the borrowing by the Partnership of $175.6 million under its senior secured revolving credit facility, and
  - our prepayment of the remaining $149.4 million balance of our senior secured term loan;
- the August 2010 completion of the sale of our interests in Versado to the Partnership, including:
  - consideration to us of $247.2 million, including 89,813 common units and 1,833 general partner units,
  - the borrowing by the Partnership of $244.7 million under its senior secured revolving credit facility, and
  - our prepayment of $91.3 million of our senior secured term loan;
- the Partnership s August 2010 issuance of $250 million of 77/8% senior secured notes due October 2018;
- the Partnership s August 2010 public offering of 7,475,000 common units;
- the Partnership s entry into an amended and restated $1.1 billion senior secured credit facility in July 2010;
- the April 2010 sale of the Permian Assets and Coastal Straddles and the September 2009 sale of the Downstream Business to the Partnership along with related financings and debt prepayments;
- our secondary public offering of 8,500,000 common units of the Partnership in April 2010; and
- our January 2010 entry into a new $600 million senior secured credit facility and related refinancing.

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Our summary unaudited pro forma condensed consolidated statement of operations data and unaudited pro forma balance sheet data give effect to this offering and to the following events that have occurred subsequent to September 30, 2010:

- the agreed repurchase on November 5, 2010 from certain holders of our Holdco Loan of $141.3 million of face value debt for $137.4 million;
- the expected award by the Company of approximately 1.9 million shares of common stock under the new stock incentive plan that we expect to adopt in connection with this offering; and
- the $18.0 million cash distribution on the Series B preferred stock that was paid on November 22, 2010. The cash distribution represents a portion of the accreted value of the Series B preferred stock included in our September 30, 2010 balance sheet.

The unaudited pro forma condensed consolidated financial information has been prepared by applying pro forma adjustments to the historical financial statements of Targa Resources Corp. The pro forma adjustments have been prepared as if the pro forma transactions had taken place on September 30, 2010, in the case of the unaudited pro forma condensed consolidated balance sheet, or as of January 1, 2009, in the case of the unaudited pro forma condensed consolidated statement of operations.

We derived the information in the following table from, and that information should be read together with and is qualified in its entirety by reference to, the historical combined and unaudited pro forma condensed consolidated financial statements and the accompanying notes included elsewhere in this prospectus.

	Consolidated Historical for Targa Resources Corp.					**Pro Forma Targa Resources Corp.**	
	For the Years Ended December 31,			**For the Nine Months Ended September 30,**		**Year Ended December 31,**	**Nine Months Ended September 30,**
	2007	**2008**	**2009**	**2009**	**2010**	**2009**	**2010**
	(In millions, except operating and price data)						
Consolidated Statement of Operations Data:							
Revenues[1]	$ 7,297.2	$ 7,998.9	$ 4,536.0	$ 3,145.0	$ 3,942.0	$ 4,536.0	$ 3,942.0
Costs and expenses:							
Product purchases	6,525.5	7,218.5	3,791.1	2,624.9	3,387.6	3,791.1	3,387.6
Operating expenses	247.1	275.2	235.0	182.7	190.4	235.0	190.4
Depreciation and amortization expenses	148.1	160.9	170.3	127.9	136.9	170.3	136.9
General and administrative expenses	96.3	96.4	120.4	83.6	81.0	132.1	89.8
Other	(0.1)	13.4	2.0	1.8	(0.4)	2.0	(0.4)

Total costs and expenses	7,016.9	7,764.4	4,318.8	3,020.9	3,795.5	4,330.5	3,804.3
Income from operations	280.3	234.5	217.2	124.1	146.5	205.5	137.7
Other income (expense):							
Interest expense, net	(162.3)	(141.2)	(132.1)	(102.8)	(83.9)	(128.2)	(78.6)
Equity in earnings of unconsolidated investments	10.1	14.0	5.0	3.2	3.8	5.0	3.8
Gain (loss) on debt repurchases		25.6	(1.5)	(1.5)	(17.4)	(1.5)	(17.4)
Gain (loss) on early debt extinguishment		3.6	9.7	10.4	8.1	9.7	8.1
Gain on insurance claims		18.5					
Other		(1.3)	1.5	2.4	0.4	1.5	0.4
Income before income taxes	128.1	153.7	99.8	35.8	57.5	92.0	54.0
Income tax expense:	(23.9)	(19.3)	(20.7)	(5.1)	(18.5)	(22.5)	(18.9)
Net income	104.2	134.4	79.1	30.7	39.0	69.5	35.1

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	Consolidated Historical for Targa Resources Corp.					Pro Forma Targa Resources Corp.	
	For the Years Ended December 31,			For the Nine Months Ended September 30,		Year Ended December 31,	Nine Months Ended September 30,
	2007	2008	2009	2009	2010	2009	2010
	(In millions, except operating and price data)						
Less: Net income attributable to non controlling interest	48.1	97.1	49.8	17.7	46.2	101.9	75.1
Net income (loss) attributable to Targa Resources Corp.	56.1	37.3	29.3	13.0	(7.2)	(32.4)	(40.0)
Dividends on Series B preferred stock	(31.6)	(16.8)	(17.8)	(13.2)	(8.4)		
Undistributed earnings attributable to preferred shareholders[(2)]	(24.5)	(20.5)	(11.5)				
Distributions to common equivalents					(177.8)		
Net income (loss) available to common shareholders	$	$	$	$ (0.2)	$ (193.4)	$ (32.4)	$ (40.0)
Net income (loss) available per common share basic and diluted	$	$	$	$ (0.03)	$ (21.51)	$ (0.77)	$ (0.95)

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	Consolidated Historical for Targa Resources Corp.					Pro Forma Targa Resources Corp.	
	For the Years Ended December 31,			For the Nine Months Ended September 30,		Year Ended December 31,	Nine Months Ended September 30,
	2007	2008	2009	2009	2010	2009	2010
	(In millions, except operating and price data)						
Financial data:							
Gross margin(3)	$ 771.7	$ 780.4	$ 744.9	$ 520.1	$ 554.4		
Operating margin(4)	524.6	505.2	509.9	337.4	364.0		
Operating data:							
Plant natural gas inlet, MMcf/d(5),(6)	1,982.8	1,846.4	2,139.8	2,097.7	2,296.5		
Gross NGL production, MBbl/d	106.6	101.9	118.3	117.1	120.8		
Natural gas sales, Bbtu/d(6)	526.5	532.1	598.4	590.4	678.4		
NGL sales, MBbl/d	320.8	286.9	279.7	285.1	246.0		
Condensate sales, MBbl/d	3.9	3.8	4.7	4.8	3.6		
Average realized prices(7):							
Natural gas, $/MMBtu	$ 6.56	$ 8.20	$ 3.96	$ 3.78	$ 4.61		
NGL, $/gal	1.18	1.38	0.79	0.71	1.03		
Condensate, $/Bbl	70.01	91.28	56.31	54.36	73.42		
Balance Sheet Data (at period end):							
Property plant and equipment, net	$ 2,430.1	$ 2,617.4	$ 2,548.1	$ 2,563.9	$ 2,494.9		$ 2,494.9
Total assets	3,795.1	3,641.8	3,367.5	3,273.0	3,460.0		3,297.4
Long-term debt, less current maturities	1,867.8	1,976.5	1,593.5	1,622.6	1,663.4		1,522.1
Convertible cumulative participating Series B preferred stock	273.8	290.6	308.4	303.8	96.8		
Total owners equity	574.1	822.0	754.9	789.9	994.3		1,069.8
Cash Flow Data:							
Net cash provided by (used in):							
Operating activities	$ 190.6	$ 390.7	$ 335.8	$ 202.9	$ 104.0		
Investing activities	(95.9)	(206.7)	(59.3)	(50.7)	(81.8)		
Financing activities	(59.5)	0.9	(386.9)	(327.1)	75.4		

(1) Includes business interruption insurance revenues of $3.0 million and $7.9 million for the nine months ended September 30, 2010 and 2009 and $21.5 million, $32.9 million and $7.3 million for the years ended December 31, 2009, 2008, and 2007.

(2) Based on the terms of the preferred convertible stock, undistributed earnings of the Company are allocated to the preferred stock until the carrying value has been recovered.

(3) 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.

(4) 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.

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

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

(7) 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 for distribution to you and would probably be required to reduce the dividend per share of common stock paid to you. You should also be aware that 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 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 will 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.

For additional information, please read Our Dividend Policy. In the future, we may not be able to pay dividends at or above our estimated initial quarterly dividend of $0.2575 per share, or $1.03 per share on an

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

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

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

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

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

We currently manage our investment in the Partnership through our ownership interest in the General Partner. The Partnership s partnership agreement, however, gives unitholders of the Partnership the right to remove the General Partner upon the affirmative vote of holders of 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

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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 distribute to our stockholders.

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

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

In preparing the pro forma financial information included in this prospectus, we have made adjustments to our historical financial information based upon currently available information and upon assumptions that our management believes are reasonable in order to reflect, on a pro forma basis, the impact of the items discussed in our unaudited pro forma financial statements and related notes. The estimates and assumptions used in the calculation of the pro forma financial information in this prospectus may be materially different from our actual experience as a public entity. Accordingly, the pro forma financial information included in this prospectus does not purport to represent what our results of operations would actually have been had we operated as a public entity during the periods presented or what our results of operations and financial condition will be in the future, nor does the pro forma financial information give effect to any events other than those discussed in our unaudited pro forma financial statements and related notes.

The assumptions underlying our TRC minimum estimated cash available for distribution for the three month period ending December 31, 2010 and the twelve month period ending December 31, 2011, included in Our Dividend Policy involve inherent and significant business, economic, financial, regulatory and competitive risks and uncertainties that could cause actual results to differ materially from those estimated.

Our estimate of cash available for distribution for the three month period ending December 31, 2010 and the twelve month period ending December 31, 2011 set forth in Our Dividend Policy has been prepared by management, and we have not received an opinion or report on it from our or any other independent registered public accounting firm. The assumptions underlying the forecasts are inherently

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uncertain and are subject to significant business, economic, financial, regulatory and competitive risks and uncertainties that could cause actual results to differ materially from those forecasted. If we do not achieve the forecasted results, we may not be able to pay a quarterly dividend on our common stock, in which event the market price of our common stock may decline materially. For further discussion on our ability to pay a quarterly dividend, please read Our Dividend Policy.

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

Effective internal controls are necessary for us to provide timely and reliable financial reports and effectively prevent fraud. If we cannot provide timely and reliable financial reports or prevent fraud, our reputation and operating results would be harmed. We continue to enhance our internal controls and financial reporting capabilities. These enhancements require a significant commitment of resources, personnel and the development and maintenance of formalized internal reporting procedures to ensure the reliability of our financial reporting. Our efforts to update and maintain our internal controls may not be successful, and we may be unable to maintain adequate controls over our financial processes and reporting in the future, including future compliance with the obligations under Section 404 of the Sarbanes-Oxley Act of 2002. Any failure to develop or maintain effective controls, or difficulties encountered in their implementation or other 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;

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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 initial public offering price of our common stock may not be indicative of the market price of our common stock after this offering. In addition, an active liquid trading market for our common stock may not develop and our stock price may be volatile.

Prior to this offering, our common stock was not traded on any market. An active and liquid trading market for our common stock may not develop or be maintained after this offering. Liquid and active trading markets usually result in less price volatility and more efficiency in carrying out investors purchase and sale orders. The market price of our common stock could vary significantly as a result of a number of factors, some of which are beyond our control. In the event of a drop in the market price of our common stock, you could lose a substantial part or all of your investment in our common stock. The initial public offering price will be negotiated between the selling stockholders and representatives of the underwriters, based on numerous factors which are discussed in the Underwriting section of this prospectus, and may not be indicative of the market price of our common stock after this offering. Consequently, you may not be able to sell shares of our common stock at prices equal to or greater than the price paid by you in the offering.

The following factors could affect our stock price:

our and the Partnership s operating and financial performance;

quarterly variations in the rate of growth of our and the Partnership s financial indicators, such as net income per share, net income and revenues;

changes in revenue or earnings estimates or publication of reports by equity research analysts relating to us or the Partnership;

speculation in the press or investment community;

sales of our common stock by us, the selling stockholders or other stockholders, or the perception that such sales may occur;

general market conditions, including fluctuations in commodity prices; and

- domestic and international economic, legal and regulatory factors unrelated to our performance.

The stock markets in general have experienced volatility that has often been unrelated to the operating performance of particular companies. These broad market fluctuations may adversely affect the trading price of our common stock.

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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 will need to 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 will occupy a significant amount of time of our board of directors and management and will significantly increase our costs and expenses. We will need to:

- institute a more comprehensive compliance function;
- design, establish, 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;
- establish new 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, we also expect that being a public company will require us to accept less director and officer liability insurance coverage than we desire or to incur additional costs to maintain coverage. These factors could also 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 42,292,348 outstanding shares of common stock. This number consists of 16,375,000 shares that the selling stockholders are selling in this offering (assuming no exercise of the underwriters over-allotment option), which may be resold immediately in the public market. Following the completion of this offering, the existing stockholders will own approximately 26 million shares, or approximately 61.3% of our total outstanding shares, all of which are restricted from immediate resale under the federal securities laws. A substantial portion of such shares are subject to the lock-up agreements between such parties and the underwriters described in Underwriting, but may be sold into the market in the future. Certain of our existing stockholders are party to a registration rights agreement with us which requires us to effect the registration of their shares in certain circumstances no earlier than the expiration of the lock-up period contained in the underwriting agreement entered into in connection with this offering.

As soon as practicable after this offering, we intend to file a registration statement with the SEC on Form S-8 providing for the registration of 5 million shares of our common stock issued or reserved for issuance under our stock incentive plan. Subject to the satisfaction of vesting conditions and the expiration of lock-up agreements, shares registered under this registration statement on Form S-8 will be available for resale immediately in the public market without restriction.

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

- a classified board of directors, so that only approximately one-third of our directors are elected each year;
- limitations on the removal of directors; and
- limitations on the ability of our stockholders to call special meetings and establish advance notice provisions for stockholder proposals and nominations for elections to the board of directors to be acted upon at meetings of stockholders.

Delaware law prohibits us from engaging in any business combination with any interested stockholder, meaning generally that a stockholder who beneficially owns more than 15% of our stock cannot acquire us for a period of three years from the date this person became an interested stockholder, unless various conditions are met, such as approval of the transaction by our board of directors. We anticipate opting 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 6.5% ownership interest in us and is selling 1,324,268 shares of common stock in connection with this offering and will own 1,433,795 shares of our common stock, representing a 3.4% 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 (including in negotiating the initial public offering price) and the interests of its affiliate ML Ventures as a selling stockholder. Because of this relationship, this offering is being conducted in accordance with Rule 2720 of the NASD Conduct Rules (which are part of the FINRA Rules). 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 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 38.2% of our outstanding common stock based on the assumed rate of conversion of our preferred stock into common stock upon completion of this offering as described under Summary Our Structure and Ownership After This Offering. See Security Ownership of Management and Selling Stockholders. Accordingly, Warburg Pincus will exert significant influence over us and any action requiring the approval of the holders of our stock, including the election of directors and approval of significant corporate transactions. Warburg s concentrated ownership makes it less likely that any other holder or group of holders of common stock will be able to affect the way we are managed or the direction of our business. These factors also may delay or prevent a change in our management or voting control.

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

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.

We anticipate that substantially all of our officers and certain members of our board of directors will be officers or directors of the General Partner and, as a result, will 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 list

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of our officers and directors that will serve in the same capacity for the General Partner and a discussion of 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 2011.

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, 2010. However, for taxable years beginning after December 31, 2010, 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. On July 19, 2010, the Partnership entered into a new five-year $1.1 billion senior secured revolving 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. As of September 30, 2010, the Partnership had approximately $753 million of borrowings outstanding under its senior secured credit facility, approximately $102 million of letters of credit outstanding and approximately $245 million of additional borrowing capacity under its senior secured credit facility. For the year ended December 31, 2009 and the quarter ended September 30, 2010, the Partnership s consolidated interest expense was $118.6 million and $23.3 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

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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 September 30, 2010, its total indebtedness was $1,433.2 million, of which $679.9 million was at fixed interest rates and $753.3 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 $4.5 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 September 30, 2010, the Partnership had approximately $753 million of borrowings outstanding under its senior secured credit facility, approximately, $102 million of letters of credit outstanding and approximately $245 million of additional borrowing capacity. 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 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 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 dividends on its equity securities or redeem, repurchase or retire its equity securities or subordinated indebtedness;
- make investments;
- create restrictions on the payment of dividends or other distributions to its equity holders;
- engage in transactions with its affiliates;
- sell assets, including equity securities of its subsidiaries;

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. 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 nine months ended September 30, 2010 and the year ended December 31, 2009, its percent-of-proceeds arrangements accounted for approximately 37% and 48% of its gathered natural gas volume. Under percent-of-proceeds 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 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.

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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.

Current weak economic conditions and the volatility and disruption in the weak financial markets have increased 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.

Global financial markets and economic conditions have been, and continue to be, disrupted and volatile. The debt and equity capital markets have been exceedingly distressed. These issues, along with significant write-offs in the financial services sector, the re-pricing of credit risk and the current weak economic conditions have made, and will likely continue to make, it difficult to obtain funding.

In particular, the cost of raising money in the debt and equity capital markets has increased substantially while the availability of funds from those markets generally has diminished significantly. Also, as a result of concerns about the stability of financial markets generally and the solvency of counterparties specifically, the cost of obtaining funds 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 the Partnership s current debt and reduced and, in some cases, ceased to provide funding to borrowers.

In addition, the Partnership is experiencing increased competition for the types of assets it contemplates purchasing. The weak economic conditions and competition for asset purchases could limit the Partnership s ability to fully execute its growth strategy. The Partnership s inability to execute its growth strategy could materially adversely affect its ability to maintain or pay higher distributions in the future.

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

Weather conditions have a significant impact on the demand for propane because end-users depend on propane principally for heating purposes. Warmer-than-normal temperatures in one or more regions in which the Partnership operates can significantly decrease the total volume of propane it sells. Lack of consumer demand for propane may also adversely affect the retailers the Partnership transacts with 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 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.

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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, 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 resulting from governmental regulation of motor gasoline and in demand for ethylene and propylene could adversely affect demand for natural gasoline.

NGLs and products produced from NGLs also compete with 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.

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

For the nine months ended September 30, 2010 and the year ended December 31, 2009, approximately 12% and 16% of the Partnership s consolidated revenues were derived from transactions with CPC. Under many of the Partnership s CPC contracts where it purchases or markets NGLs on CPC s behalf, CPC may elect to terminate the contracts or renegotiate the price terms. To the extent CPC reduces the volumes of NGLs that it purchases from the Partnership or reduces the volumes of NGLs that the Partnership markets on its behalf, or to the extent the economic terms of such contracts are changed, the Partnership s revenues and cash available for debt service could decline.

The tax treatment of the Partnership depends on its status as a partnership for federal income tax purposes as well as its not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue

Service (IRS) were to treat the

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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 15% 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.

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 the gathering, compressing, treating, processing and transporting of natural gas and the fractionation, storage and transportation of 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 $5.1 million between 2010 and 2012 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 this regulation, 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. Following the initial round of testing and repairs, 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.

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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 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 obligations 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 wastes 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 wastes 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 has conducted a series of analyses 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, and the analysis could result in the adoption of new air emission regulatory or permitting limitations that could require the Partnership to incur increased capital or operating costs. 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. The Partnership may not be able to recover some or any of these costs from insurance.

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. Due to concerns that hydraulic fracturing may adversely affect drinking water supplies, the U.S. Environmental Protection Agency (EPA) recently announced its plan to conduct a comprehensive research study to investigate the potential adverse impact that hydraulic fracturing may have on water quality and public health. The initial study results are expected to be available in late 2012. Additionally, legislation has been introduced in the U.S. Congress to amend the federal Safe Drinking Water Act to subject hydraulic fracturing operations to regulation under that Act and to require the disclosure of chemicals used by the oil and gas industry in the hydraulic fracturing process. If enacted, such a provision could require hydraulic fracturing activities to meet permitting and financial assurance requirements, adhere to certain construction specifications, fulfill monitoring, reporting and recordkeeping requirements and meet plugging and abandonment requirements. In unrelated oil spill legislation being considered by the U.S. Senate in the aftermath of the April 2010 Macondo well release in the Gulf of Mexico, an amending provision has been prepared that would require natural gas drillers to disclose the chemicals they pump into the ground as part of the hydraulic fracturing process. Disclosure of chemicals used in the fracturing process could make it easier for third parties opposing hydraulic fracturing to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. 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 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 ICA are exempt from regulation by FERC under the ICA as proprietary lines. The classification of a line as a proprietary line is a fact-based determination subject to FERC and court review. Accordingly, the classification and regulation of some of the Partnership s gathering facilities and transportation pipelines may be subject to change based on future determinations by FERC, the courts, or Congress.

While the 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 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. In June 2010, FERC issued an Order granting clarification regarding Order 704.

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 Targa Louisiana Intrastate LLC is exempt from this rule.

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

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.

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.

Climate change legislation and regulatory initiatives could result in increased operating costs and reduced demand for the natural gas and NGL services the Partnership provides.

On December 15, 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases (GHGs) present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth s atmosphere and other climatic changes. 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. Accordingly, the EPA has adopted two sets of regulations under the Clean Air Act that would require a reduction in emissions of GHGs from motor vehicles and could trigger permit review for GHG emissions from certain stationary sources. Moreover, on October 30, 2009, the EPA published a Mandatory Reporting of Greenhouse Gases final rule that establishes a new comprehensive scheme requiring operators of stationary sources emitting more than established annual thresholds of carbon dioxide-equivalent GHGs to inventory and report their GHG emissions annually on a facility-by-facility basis. 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, beginning in 2012 for emissions occurring in 2011.

In addition, both houses of Congress have actively 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 with the number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved. The adoption of legislation or regulations imposing reporting or permitting obligations on, or limiting emissions of GHGs from, the Partnership s equipment and operations could require it to incur additional 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 the natural gas it gathers, treats or otherwise handles in connection with its services.

The recent adoption of derivatives legislation by the United States Congress could have an adverse effect on the Partnership s ability to hedge 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 was signed into law by the President on July 21, 2010, and requires the Commodities Futures Trading Commission (the CFTC) and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. The CFTC has also proposed regulations to set position limits for certain futures and option contracts in the major energy markets, although it is not possible at this time to predict whether or when the CFTC will adopt those rules or include comparable provisions in its rulemaking under the new legislation. The financial reform legislation may also require the Partnership to comply with margin 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 also requires many 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 those 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 the 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 Interstate Commerce Act (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.

On April 20, 2010, the Transocean Deepwater Horizon drilling rig exploded and subsequently sank 130 miles south of New Orleans, Louisiana, 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. The Partnership cannot predict with any certainty the impact of this oil spill, the extent of cleanup activities associated with this spill, or possible changes in laws or regulations that 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. 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 $2.5 million of expenses in connection with this offering, including all expenses of the selling stockholders which we have agreed to pay and a structuring fee of approximately $900,625 to be paid to Barclays Capital Inc. for evaluation, structuring and analysis in connection with the offering.

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CAPITALIZATION

The following table sets forth our cash and cash equivalents and capitalization as of September 30, 2010,

on an actual basis;

on an as adjusted basis to give effect to the repayment of $141.3 million of face value of indebtedness under the Holdco Loan for $137.4 million and the $18 million repayment of the accreted value of the Series B Preferred included in our September 30, 2010 balance sheet; and

on an as further adjusted basis to give effect to the transactions described under Summary Our Structure and Ownership After This Offering.

You should read the following table in conjunction with Selected Historical Financial and Operating Data, Management s Discussion and Analysis of Financial Condition and Results of Operations and our historical consolidated financial statements and related notes thereto appearing elsewhere in this prospectus.

	Actual 9/30/10	As Adjusted	As Adjusted For Offering
	($ in millions)		
Cash & Cash Equivalents[(1)]	$ 350.0	$ 194.6	$ 188.3
Debt:			
Our Obligations:			
Holdco Loan, due February 2015	$ 230.2	$ 88.9	$ 88.9
TRI Senior secured revolving credit facility, due July 2014[(2)]			
TRI Senior secured term loan facility, due July 2016			
Unamortized discounts, net of premiums			
Obligations of the Partnership:			
Senior secured revolving credit facility, due July 2015	753.3	753.3	753.3
81/4% Senior unsecured notes, due July 2016	209.1	209.1	209.1
111/4% Senior unsecured notes, due July 2017	231.3	231.3	231.3
77/8% Senior unsecured notes, due October 2018	250.0	250.0	250.0
Unamortized discounts, net of premiums	(10.5)	(10.5)	(10.5)
Total Debt	1,663.4	1,522.1	1,522.1
Series B preferred stock	96.8	78.8	
Targa Resources Corp. stockholders equity	58.8	62.8	134.3
Noncontrolling interest in subsidiaries	935.5	935.5	935.5
Total Capitalization	$ 2,754.5	$ 2,599.2	$ 2,591.9

(1)

At closing we expect to have sufficient cash to satisfy certain tax, capital expenditure, and other obligations. See Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources.

(2) In conjunction with the sale of our interests in Versado to the Partnership, the revolving credit facility commitment was reduced to $75 million.

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.

Based on the current distribution policy of the Partnership, expected cash to be received from the Partnership, our expected federal income tax liabilities, our expected level of other expenses and reserves that our board of directors believes prudent to maintain, we expect that our initial quarterly dividend rate will be $0.2575 per share. 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 expect to pay a pro rated dividend for the portion of the fourth quarter of 2010 that we are public in February 2011. However, we cannot assure you that any dividends will be declared or paid.

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

The Partnership s Cash Distribution Policy

Under the Partnership s partnership agreement, 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, based on the 2010 fourth quarter distribution management plans to recommend to the General Partner s board of directors.

Overview of Presentation

In the sections that follow, we present in detail the basis for our belief that we will be able to fully fund our initial quarterly dividend of $0.2575 per share of common stock for each quarter through the quarter ending December 31, 2011. In these sections, we present three tables, including:

- our Unaudited Pro Forma Available Cash, in which we present the amount of available cash we would have had available for dividends to our shareholders on a pro forma basis for the year ended December 31, 2009 and for the twelve months ended September 30, 2010; and

- our TRC Minimum Estimated Cash Available for Distribution for the Twelve Month Period Ending December 31, 2011 and TRC Minimum Estimated Cash Available for Distribution for the Three Month Period Ending December 31, 2010 in which we present our estimate of the Adjusted EBITDA necessary for the Partnership to pay distributions to its partners, including us, to enable us to have sufficient cash available for distribution to fund quarterly dividends on all outstanding common shares for each quarter through the quarter ending December 31, 2011.

Targa Resources Corp. Unaudited Pro Forma Available Cash for the Year Ended December 31, 2009 and the Twelve Months Ended September 30, 2010

Our pro forma available cash for the year ended December 31, 2009 and the twelve months ended September 30, 2010 would have been sufficient to pay the initial quarterly dividend of $0.2575 per share of common stock outstanding following the completion of this offering.

Pro forma cash available for distribution includes estimated incremental general and administrative expenses we will incur as a result of being a public corporation, such as costs associated with preparation and distribution of annual and quarterly reports to shareholders, tax returns, investor relations, registrar and transfer agent fees, director compensation and incremental insurance costs, including director and officer liability insurance. We expect that these items will increase our annual general and administrative expenses by approximately $1 million.

The table below reconciles the Partnership s historical financial results to our minimum cash available for distribution and illustrates that we would have had cash distributions on our interests in the Partnership sufficient to pay dividends to our shareholders at the initial quarterly dividend of $0.2575 per share. The table reconciles the Partnership s historical financial results to its Adjusted EBITDA for the year ended December 31, 2009 and for the twelve months ended September 30, 2010 and then reconciles Adjusted EBITDA to pro forma cash available for distribution to all of the Partnership s unitholders.

The Partnership s pro forma cash available for distribution is derived from its historical financial statements included in its Current Report on Form 8-K filed with the SEC on October 4, 2010, and its Quarterly Report on Form 10-Q filed with the SEC on November 5, 2010. Under common control accounting, the Partnership s financial results include the historical financial results of the assets acquired from us. The only pro forma adjustments to such historical financial results are to (i) present prior period interest expense based on the Partnership s current debt balance as reflected in the pro forma cash interest expense line in the table below and (ii) current units outstanding of 75,545,409 units for all periods presented. The pro forma cash available for distribution should not be considered indicative of our results of operations had the transactions contemplated in our unaudited pro forma condensed consolidated financial statements actually been consummated on January 1, 2009.

Targa Resources Corp.

Unaudited Pro Forma Available Cash

	Year Ended December 31, 2009	Twelve Months Ended September 30, 2010
	(In millions, except per share amounts)	
Targa Resources Partners LP Data		
Revenues	$ 4,503.7	$ 5,321.4
Less: Product purchases	(3,792.9)	(4,556.2)
Gross margin[(1)]	710.8	765.2
Less: Operating expenses	(234.4)	(242.4)
Operating margin[(2)]	476.4	522.8
Less:		
Depreciation and amortization expenses	(166.7)	(170.1)
General and administrative expenses	(118.5)	(116.6)
Interest expense, net	(107.0)	(107.0)
Equity in earnings of unconsolidated investment	5.0	5.6
Loss on debt repurchases	(1.5)	(0.8)
Loss on mark-to-market derivative instruments	(30.9)	7.1
Income tax expense	(1.2)	(4.2)
Net income attributable to noncontrolling interest	(19.3)	(25.5)
Other	4.4	(0.7)
Net income attributable to Targa Resources Partners LP	40.7	110.6
Plus:		
Interest expense, net	107.0	107.0
Income tax expense	1.2	4.2
Depreciation and amortization expenses	166.7	170.1
Noncash loss related to derivative instruments	92.0	15.4
Noncontrolling interest adjustment	(10.5)	(10.3)
Adjusted EBITDA[(3)]	397.1	397.0

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	Year Ended December 31, 2009	Twelve Months Ended September 30, 2010
	(In millions, except per share amounts)	
Adjusted EBITDA[3]	397.1	397.0
Less:		
Pro forma cash interest expense[4]	(101.1)	(101.1)
Maintenance capital expenditures, net	(35.3)	(40.4)
Pro forma cash available for distribution to Partnership unitholders[5]	260.7	255.5
Partnership s debt covenant ratios[6]		
Interest coverage ratio of not less than 2.25 to 1.0	3.7x	3.7x
Consolidated leverage ratio of not greater than 5.5 to 1.0	3.5x	3.6x
Consolidated senior leverage ratio of not greater than 4.0 to 1.0	1.8x	1.9x
Estimated minimum cash available for distribution to Partnership unitholders		
Estimated minimum cash distributions to us:		
2% general partner interest	3.8	3.8
Incentive distribution rights[7]	21.4	21.4
Common units	25.5	25.5
Pro forma cash distributions to us	50.7	50.7
Pro forma cash distributions to public unitholders	139.9	139.9
Total pro forma cash distributions by the Partnership	190.6	190.6
Excess / (Shortfall)	70.1	64.9
Targa Resources Corp. Data[8]		
Pro forma cash distributions to be received from the Partnership	$ 50.7	$ 50.7
Plus / (Less):		
General and administrative expenses[9]	(5.4)	(5.4)
Cash interest expense[10]	(3.4)	(3.4)
Interest income	1.7	1.7
Minimum estimated cash available for distribution	43.6	43.6
Excess / (Shortfall)		
Expected dividend per share	1.03	1.03
Total dividends paid to stockholders	$ 43.6	$ 43.6

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

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

(3) Adjusted EBITDA is presented because we believe it provides additional information with respect to both the performance of our fundamental business activities as well as our ability to meet future debt service, capital expenditures and working capital requirements. It is a non-GAAP financial measure and is not intended to be used in lieu of the GAAP presentation of net income.

(4) For the twelve months ended September 30, 2010, the Partnership s pro forma cash interest expense includes (i) $35.0 million of interest expense related to borrowings under the revolving credit facility based on an average balance of $727.3 million at an average interest rate of 4.8% (comprised of 1% LIBOR plus a borrowing spread of 2.75% plus interest rate hedge settlement of 1.1%); (ii) $62.9 million of interest expense related to the $690 million of senior unsecured notes with a weighted average interest rate of approximately 9.1% and (iii) $3.2 million of commitment fees and letter of credit fees. After giving effect to LIBOR swaps for $300 million of the Partnership s revolving credit facility, a 1.0% change in LIBOR would result in a change in interest expense for the period of $4.3 million.

For the twelve months ended December 31, 2009, the Partnership s pro forma cash interest expense includes (i) $33.6 million of interest expense related to borrowings under the revolving credit facility based on an average balance of $684.5 million at an average interest rate of 4.9% (comprised of 1% LIBOR plus a spread of 2.75% plus interest rate hedge settlement of 1.2%); (ii) $62.9 million of interest expense related to the $690 million of senior unsecured notes with a weighted average interest rate of approximately 9.1% and (iii) $4.5 million of commitment fees and letter of credit fees. After giving effect to LIBOR swaps for $300 million of the Partnership s revolving credit facility, a 1.0% change in LIBOR would result in a change in interest for the period of $3.9 million.

Cash interest expense excludes $5.9 million of non-cash interest expense for both periods.

(5) The Partnership s pro forma cash available for distribution is presented because we believe it is used by investors to evaluate the ability of the Partnership to make quarterly cash distributions. It is a non-GAAP financial measure and is not intended to be used in lieu of the GAAP presentation of net income.

(6) The Partnership s credit agreement and indentures contain certain financial covenants. The Partnership s revolving credit facility requires that, at the end of each fiscal quarter, the Partnership must maintain:

an interest coverage ratio, defined as the ratio of the Partnership s consolidated adjusted EBITDA (as defined in the Amended and Restated Credit Agreement) for the four consecutive fiscal quarters most recently ended to the consolidated interest expense (as defined in the Amended and Restated Credit Agreement) for such period, of no less than 2.25 to 1.0;

a Consolidated Leverage Ratio, defined as the ratio of the Partnership s consolidated funded indebtedness (as defined in the Amended and Restated Credit Agreement) to consolidated adjusted EBITDA, for the four fiscal quarters most recently ended, that is not greater than 5.5 to 1.0; and

a Consolidated Senior Leverage ratio, defined as the ratio of the Partnership s consolidated funded indebtedness, excluding unsecured note indebtedness, to consolidated adjusted EBITDA, for the four fiscal quarters most recently ended, that is not greater than 4.0 to 1.0.

In addition, the indentures relating to the Partnership s senior notes require that the Partnership have a fixed charge coverage ratio for the most recently ended four fiscal quarters of not less than 1.75 to 1.0 in order to make distributions, subject to certain exceptions. This ratio is approximately equal to the interest coverage ratio described above. As indicated in the table, the Partnership s pro forma EBITDA would have been sufficient to permit cash distributions under the terms of its credit agreement and indentures.

(7) Our incentive distributions are based on the Partnership s 75,545,409 outstanding common units as of November 1, 2010 and the Partnership s fourth quarter 2010 quarterly distribution of $0.5475 per unit, or $2.19 per unit on an annualized basis, that management plans to recommend to the General Partner s board of directors.

(8) We will have no debt outstanding under TRI s revolving credit facility, and accordingly, we have not presented credit ratios for this facility in the table. Pursuant to the terms of this facility at the end of each fiscal quarter, TRI must maintain:

an interest coverage ratio, defined as the ratio of our consolidated adjusted EBITDA (as defined in the revolving credit agreement) for the four consecutive fiscal quarters most recently ended to the consolidated interest expense (as defined in the revolving credit agreement) for such period, of no less than 1.5 to 1.0;

a Consolidated Leverage Ratio, defined as the ratio of our consolidated funded indebtedness (as defined in the revolving credit agreement) to consolidated adjusted EBITDA, for the four fiscal quarters most recently ended, that is not greater than 5.75 to 1.0 and becomes more restrictive over time.

(9) General and administrative expenses include $1 million of incremental public company expenses.

(10) Following this offering and excluding debt of the Partnership, our only outstanding debt will be the Holdco Loan under which we have the election to pay interest in cash or in kind. We have assumed that we will pay interest in cash at an assumed interest rate of LIBOR plus a spread of 3.0%. The Holdco Loan agreement has no restrictive covenants which would impact our ability to pay dividends.

TRC Minimum Estimated Cash Available for Distribution for the Twelve Month Period Ending December 31, 2011

Set forth below is a forecast of the TRC Minimum Estimated Cash Available for Distribution that supports our belief that we expect to generate sufficient cash flow to pay a quarterly dividend of $0.2575 per common share on all of our outstanding common shares for the twelve months ending December 31, 2011, based on assumptions we believe to be reasonable.

Our minimum estimated cash available for distribution reflects our judgment as of the date of this prospectus of conditions we expect to exist and the course of action we expect to take during the twelve months ending December 31, 2011. The assumptions disclosed under Assumptions and Considerations below are those that we believe are significant to our ability to generate such minimum estimated cash available for distribution. We believe our actual results of operations and cash flows for the twelve months ending December 31, 2011 will be sufficient to generate our minimum

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estimated cash available for distribution for such period; however, we can give you no assurance that such minimum estimated cash available for distribution will be achieved. There will likely be differences between our minimum estimated cash available for distribution for the twelve months ending December 31, 2011 and our actual results for such period and those differences could be material. If we fail to generate the minimum estimated cash available for distribution for the twelve months ending December 31, 2011, we may not be able to pay cash dividends on our common shares at the initial dividend rate stated in our cash dividend policy for such period.

Our minimum estimated cash available for distribution required to pay dividends to all our outstanding shares of common stock at the estimated annual initial dividend rate of $1.03 per share is approximately $43.6 million. Our minimum estimated cash available for distribution is comprised of cash distributions from our limited and general partnership interests in the Partnership, including the IDRs, less general and administrative expenses, less cash interest expense, if any, less federal income taxes, less capital contributions to the Partnership and less reserves established by our board of directors. Substantially all of our cash flow will be generated from our limited and general partnership interests in the Partnership. In order for our minimum estimated cash available for distribution to be approximately $43.6 million, we estimate that the Partnership must have minimum estimated cash available for distribution for the twelve months ending December 31, 2011 of $190.6 million, which would be sufficient to fund the Partnership s recommended distribution for the quarter ended December 31, 2010 of $2.19 per common unit on an annualized basis.

In order for the Partnership to have minimum estimated cash available for distribution of $190.6 million, we estimate that it must generate Adjusted EBITDA of at least $403.5 million for the twelve months ending December 31, 2011 after giving effect to a $58.8 million cash reserve. As set forth in the table below and as further explained under Assumptions and Considerations, we believe the Partnership will produce minimum estimated cash available for distribution of $190.6 million for the twelve months ending December 31, 2011.

We do not as a matter of course make public projections as to future operations, earnings or other results. However, management has prepared the minimum estimated cash available for distribution and assumptions set forth below to substantiate our belief that we will have sufficient cash available to pay the estimated annual dividend rate to our stockholders for the twelve months ending December 31, 2011. The accompanying prospective financial information was not prepared with a view toward complying with the published guidelines of the SEC or the guidelines established by the American Institute of Certified Public Accountants with respect to prospective financial information, but, in the view of our management, was prepared on a reasonable basis, reflects the best currently available estimates and judgments and presents, to the best of management s knowledge and belief, the assumptions on which we base our belief that we can generate the minimum estimated cash available for distribution necessary for us to have sufficient cash available for distribution to pay the estimated annual dividend rate to all of our stockholders for the twelve months ending December 31, 2011. However, this information is not fact and should not be relied upon as being necessarily indicative of future results, and readers of this prospectus are cautioned not to place undue reliance on the prospective financial information. The prospective financial information included in this prospectus has been prepared by, and is the responsibility of, our management. PricewaterhouseCoopers LLP has neither examined, compiled nor performed any procedures with respect to the accompanying prospective financial information and, accordingly, PricewaterhouseCoopers LLP does not express an opinion or any other form of assurance with respect thereto. The PricewaterhouseCoopers LLP reports included in this prospectus relate to our historical financial information. Such reports do not extend to the prospective financial information of the Partnership or us and should not be read to do so.

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We are providing the minimum estimated cash available for distribution and related assumptions for the twelve months ending December 31, 2011 to supplement our pro forma and historical financial statements in support of our belief that we will have sufficient available cash to allow us to pay cash dividends on all of our outstanding shares of common stock for each quarter in the twelve month period ending December 31, 2011 at our stated initial quarterly dividend rate. Please read below under Assumptions and Considerations for further information as to the assumptions we have made for the preparation of the minimum estimated cash available for distribution set forth below.

We do not undertake any obligation to release publicly the results of any future revisions we may make to the assumptions used in generating our minimum estimated cash available for distribution for the twelve months ending December 31, 2011 or to update those assumptions to reflect events or circumstances after the date of this prospectus. Therefore, you are cautioned not to place undue reliance on this information.

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TRC Minimum Estimated Cash Available for Distribution for the Twelve Month Period Ending December 31, 2011

		Twelve Months Ending December 31, 2011 (In millions except per unit and per share amounts)
Targa Resources Partners LP Data		
Revenues	$	6,098.1
Less: product purchases		(5,264.5)
Gross margin[1]		833.6
Less: operating expenses		(289.3)
Operating margin[2]		544.3
Less:		
Depreciation and amortization expenses		(175.4)
General and administrative expenses		(110.3)
Income from operations		258.6
Plus (less) other income (expense)		
Interest expense, net		(110.3)
Equity in earnings of unconsolidated investment		11.5
Income before income taxes		159.8
Less: income tax expense		(2.5)
Net income		157.3
Less: net income attributable to noncontrolling interest[3]		(31.2)
Net income attributable to Targa Resources Partners LP	$	126.1
Plus:		
Interest expense, net		110.3
Income tax expense		2.5
Depreciation and amortization expenses		175.4
Non-cash loss related to derivative instruments		0.4
Noncontrolling interest adjustment		(11.2)
Estimated Adjusted EBITDA[4]	$	403.5
Less:		
Interest expense, net		(110.3)
Expansion capital expenditures, net		(129.0)
Borrowings for expansion capital expenditures		129.0
Maintenance capital expenditures, net		(49.7)

Amortization of debt issue costs		5.9
Cash reserve[5]		(58.8)
Estimated minimum cash available for distribution[6]	$	190.6
Partnership debt covenant ratios[7]		
Interest coverage ratio of not less than 2.25 to 1.0		3.7x
Consolidated leverage ratio of not greater than 5.5 to 1.0		4.0x
Consolidated senior leverage ratio of not greater than 4.0 to 1.0		2.2x
Estimated minimum cash available for distribution to Partnership unitholders		
Estimated minimum cash distributions to us:		
2% general partner interest	$	3.8
Incentive distribution rights[8]		21.4
Common units		25.5
Total estimated minimum cash distributions to us		50.7
Estimated minimum cash distributions to public unitholders		139.9
Total estimated minimum cash distributions by the Partnership	$	190.6

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		Twelve Months Ending December 31, 2011 (In millions except per share amounts)
Targa Resources Corp. Data[9][10]		
Minimum estimated cash distributions to be received from the Partnership	$	50.7
Corporate general and administrative expenses[11]		(5.4)
Partnership distributions less general and administrative expenses		45.3
Plus / (Less):		
Interest Expense		(3.4)
Interest Income		1.7
Cash taxes paid		(14.3)
Cash taxes funded from cash on hand		14.3
Minimum estimated cash available for distribution	$	43.6
Expected dividend per share, on an annualized basis	$	1.03
Total estimated dividends paid to stockholders	$	43.6

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

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

(3) Reflects net income attributable to Chevron s 37% interest in Versado, Enterprise s 12% interest in VESCO, ONEOK s 11% interest in VESCO and BP s 12% interest in CBF.

(4) Adjusted EBITDA is presented because we believe it provides additional information with respect to both the performance of our fundamental business activities as well as our ability to meet future debt service, capital expenditures and working capital requirements. It is a non-GAAP financial measure and is not intended to be used in lieu of the GAAP presentation of net income.

(5) Represents a discretionary cash reserve. See The Partnership s Cash Distribution Policy.

(6) The Partnership s estimated minimum cash available for distribution is presented because we believe it is used by investors to evaluate the ability of the Partnership to make quarterly cash distributions. It is a non-GAAP financial measure and is not intended to be used in lieu of the GAAP presentation of net income.

(7) The Partnership s credit agreement and indentures contain certain financial covenants. The Partnership s revolving credit facility requires that, at the end of each fiscal quarter, the Partnership must maintain:

an interest coverage ratio, defined as the ratio of the Partnership s consolidated adjusted EBITDA (as defined in the Amended and Restated Credit Agreement) for the four consecutive fiscal quarters most recently ended to the consolidated interest expense (as defined in the Amended and Restated Credit Agreement) for such period, of no less than 2.25 to 1.0;

a Consolidated Leverage Ratio, defined as the ratio of the Partnership s consolidated funded indebtedness (as defined in the Amended and Restated Credit Agreement) to consolidated adjusted EBITDA, for the four fiscal quarters most recently ended, that is not greater than 5.5 to 1.0; and

a Consolidated Senior Leverage ratio, defined as the ratio of the Partnership s consolidated funded indebtedness, excluding unsecured note indebtedness, to consolidated adjusted EBITDA, for the four fiscal quarters most recently ended, that is not greater than 4.0 to 1.0.

In addition, the indentures relating to the Partnership s existing senior notes require that the Partnership have a fixed charge coverage ratio for the most recently ended four fiscal quarters of not less than 1.75 to 1.0 in order to make distributions, subject to certain exceptions. This ratio is approximately equal to the interest coverage ratio described above. As indicated by the table, we estimate that the Partnership s pro forma EBITDA would be sufficient to permit cash distributions, under the terms of its credit agreement and indentures.

(8) Based on the Partnership s 75,545,409 outstanding common units as of November 1, 2010 and the Partnership s fourth quarter 2010 quarterly distribution of $0.5475 per unit, or $2.19 per unit on an annualized basis, that management plans to recommend to the General Partner s board of directors.

(9) We expect that we will have no debt outstanding under TRI s revolving credit facility, and accordingly, we have not presented credit ratios for this facility in the table. Pursuant to the terms of this facility at the end of each fiscal quarter, TRI must maintain:

an interest coverage ratio, defined as the ratio of our consolidated adjusted EBITDA (as defined in the revolving credit agreement) for the four consecutive fiscal quarters most recently ended to the consolidated interest expense (as defined in the revolving credit agreement) for such period, of no less than 1.5 to 1.0;

a Consolidated Leverage Ratio, defined as the ratio of our consolidated funded indebtedness (as defined in the revolving credit agreement) to consolidated adjusted EBITDA, for the four fiscal quarters most recently ended, that is not greater than 5.75 to 1.0 and becomes more restrictive over time.

(10) The Holdco Loan agreement has no restrictive covenants which would impact our ability to pay dividends.

(11) General and administrative expenses include $3 million of public company expenses, including $1 million of estimated incremental public company expenses. TRI Resources Inc. was required to file reports under the Securities Exchange Act of 1934 until January 2010, and, accordingly, recognized costs associated with being a public company prior to that time.

Assumptions and Considerations

General

We estimate that our ownership interests in the Partnership will generate sufficient cash flow to enable us to pay our initial quarterly dividend of $0.2575 per share on all of our shares for the four quarters ending December 31, 2011. Our ability to make these dividend payments assumes that the Partnership will pay its current quarterly distribution of $0.5475 per common unit for each of the four quarters ending December 31, 2011, which means that the total amount of cash distributions we will receive from the Partnership for that period would be $50.7 million.

The primary determinant in the Partnership s ability to pay a distribution of $0.5475 per common unit for each of the four quarters ending December 31, 2011, after giving effect to a $58.8 million cash reserve, is its ability to generate Adjusted EBITDA of at least $403.5 million during the period, which in turn is dependent on its ability to generate operating margin of $544.3 million. Our estimate of the Partnership s ability to generate at least this amount of operating margin is based on a number of assumptions including those set forth below.

While we believe that these assumptions are generally consistent with the actual performance of the Partnership and are reasonable in light of our current beliefs concerning future events, the assumptions are inherently uncertain and are subject to significant business, economic, regulatory and competitive risks and uncertainties that could cause actual results to differ materially from those we anticipate. If these assumptions are not realized, the actual available cash that the Partnership generates, and thus the cash we would receive from our ownership interests in the Partnership, could be substantially less than that currently expected and could, therefore, be insufficient to permit us to make our initial quarterly dividend on our shares for the forecasted period. In that event, the market price of our shares may decline materially. Consequently, the statement that we believe that we will have sufficient cash available to pay the initial dividend on our shares of common stock for each quarter through December 31, 2011, should not be regarded as a representation by us or the underwriters or any other person that we will make such a distribution. When reading this section, you should keep in mind the risk factors and other cautionary statements under the heading Risk Factors in this prospectus.

Commodity Price Assumptions. As of October 29, 2010, the NYMEX 2011 calendar strip prices for natural gas and crude oil were $4.39 per MMBtu and $84.28 per Bbl. These prices are 13.9% and 0.9%

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below the forecasted prices of $5.10 per MMBtu and $85.00 per Bbl used to calculate estimated Adjusted EBITDA.

		Twelve Months Ended	
	December 31, 2009	September 30, 2010	December 31, 2011
Natural Gas	$3.99/MMBtu	$4.48/MMBtu	$5.10/MMBtu
Ethane	$0.48/gallon	$0.61/gallon	$0.47/gallon
Propane	$0.84/gallon	$1.12/gallon	$1.05/gallon
Isobutane	$1.19/gallon	$1.53/gallon	$1.46/gallon
Normal butane	$1.08/gallon	$1.44/gallon	$1.42/gallon
Natural gasoline	$1.31/gallon	$1.75/gallon	$1.80/gallon
Crude oil	$59.80/Bbl	$76.99/Bbl	$85.00/Bbl

In addition, the Partnership s estimated Adjusted EBITDA reflects the effect of its commodity price hedging program under which it has hedged a portion of the commodity price risk related to the sale of its expected natural gas, NGL, and condensate equity volumes that result from its percent-of-proceeds processing arrangements for our Field Gathering and Processing and the LOU portion of our Coastal Gathering and Processing operations. Please see Management s Discussion and Analysis of Financial Condition and Results of Operations Factors That Significantly Affect Our Results Contract Terms and Contract Mix and the Impact of Commodity Prices. The table below summarizes the Partnership s hedged volumes for 2011 under derivative arrangements that are in place as of September 30, 2010. We estimate that these hedged volumes correspond to approximately 65% to 75% of the Partnership s expected natural gas equity volumes and approximately 50% to 60% of Partnership s expected NGLs and condensate equity volumes for 2011. The percentages hedged are derived by dividing the notional volumes hedged by a range of estimated equity volumes for 2011.

	Natural Gas	NGL	Condensate
Hedged volume swaps	30,100 MMBtu/d	7,000 Bbls/d	750 Bbls/d
Weighted average price swaps	$6.32 per MMBtu	$0.85 per gallon	$77.00 per Bbl
Hedged volume floors		253 Bbls/d	
Weighted average price floors		$1.44 per gallon	

The table below compares selected financial and volumetric data for the Partnership for the twelve months ending December 31, 2011 to the twelve months ended September 30, 2010 and December 31, 2009.

		Twelve Months Ended	
	December 31, 2009	September 30, 2010	December 31, 2011 (Estimated)
		(In millions, except for share amounts)	
Targa Resources Partners LP Data			
Revenues	$ 4,503.7	$ 5,321.4	$ 6,098.1
Less: Product purchases	(3,792.9)	(4,556.2)	(5,264.5)

Gross margin	710.8	765.2	833.6
Less: Operating expenses	(234.4)	(242.4)	(289.3)
Operating margin	476.4	522.8	544.3
Adjusted EBITDA	397.1	397.0	403.5
Maintenance capital expenditures, net	35.3	40.4	49.7
Volume Statistics:			
Inlet Volumes (MMcf/d)	2,139.8	2,288.5	2,470.2
Fractionation Volumes (MBbls/d)	217.2	221.4	291.6

Volume assumptions. For the twelve months ended September 30, 2010, plant inlet volumes increased 7% over volumes for the twelve months ended December 31, 2009. For 2011, we expect a continued increase of 8% over the twelve months ended September 30, 2010. The volume increase is driven by additional volumes on the Partnership s VESCO system (see Coastal Gathering and Processing Segment Assumptions for more detail), and expected new drilling and workover activity in our Field Gathering and Processing segment (see Field Gathering and Processing Segment Assumptions for more detail).

Fractionation volumes for 2011 are forecasted to increase 32% over the twelve months ended September 30, 2010 primarily due to the 78 MBbl/d CBF expansion, which is expected to be in service in the second quarter of 2011.

Revenue assumptions. 2011 revenue is forecasted to increase 15% over the twelve months ended September 30, 2010 and 35% over 2009. The increase in revenue is primarily due to higher plant inlet and fractionation volumes and higher commodity prices as presented in the table above.

Product purchase assumptions. Product purchases are forecasted to increase 16% over the twelve months ended September 30, 2010 and 39% over 2009 primarily due to increased settlement costs associated with higher inlet volumes and increased commodity prices.

Operating expense assumptions. Operating expenses are forecasted to increase 19% over the twelve months ended September 30, 2010 and 23% over 2009 mostly due to expanded operations in our Logistics segment resulting from the CBF expansion and partial year addition of the benzene treater. Also, expenses are forecasted to be higher for our Field Gathering and Processing Segment mostly due to increased connections resulting from new drilling activity.

Operating margin assumptions. For the twelve months ended September 30, 2010, operating margin increased 10% over operating margin for the twelve months ended December 31, 2009 largely due to increases in the Field Gathering and Processing segment and the Coastal Gathering and Processing Segment. For full year 2011, we expect a continued increase of 4% over the twelve months ended September 30, 2010 largely due to increases in the Field Gathering and Processing segment and the Logistics Assets segment (see Segment Operating Margin Assumptions for more detail).

Maintenance Capital Expenditures assumptions, net. The Partnership s maintenance capital expenditures increased for the twelve months ended September 30, 2010 relative to 2009 because of a larger number of well connections associated with higher drilling activity levels for assets in our Field Gathering and Processing segment. We expect drilling activity to increase further, which will result in higher maintenance capital expenditures in 2011.

Segment Operating Margin Assumptions. Based on the pricing and other assumptions outlined above and the segment information and other assumptions discussed below, we estimate forecasted operating margin for the Partnership s segments for the twelve months ending December 31, 2011 as

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shown in following table. Selected operating and historical financial data for the Partnership for the twelve months ended September 30, 2010 and the twelve months ended December 31, 2009 is also shown.

	Twelve Months Ending		
	December 31, 2009	September 30, 2010 (In millions)	December 31, 2011 (Estimated)
Natural Gas Gathering and Processing			
Field Gathering and Processing Segment	$ 183.2	$ 236.6	$ 245.6
Coastal Gathering and Processing Segment	89.7	111.6	102.0
NGL Logistics and Marketing			
Logistics Assets Segment	74.4	79.8	118.6
Marketing and Distribution Segment	82.9	78.1	65.6
Other	46.2	16.7	12.5
Total operating margin	$ 476.4	$ 522.8	$ 544.3

Natural Gas Gathering and Processing. The Partnership s Natural Gas Gathering and Processing business includes assets used in the gathering of natural gas produced from oil and gas wells and processing this raw natural gas into merchantable natural gas by removing impurities and extracting a stream of combined NGLs or mixed NGLs. 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 Partnership s results of operations are impacted by changes in commodity prices as well as increases and decreases in the volume and thermal content of natural gas that the Partnership gathers and transports through its pipeline systems and processing plants.

Field Gathering and Processing Segment Assumptions. The following table summarizes selected operating and financial data for the Partnership for the twelve months ending December 31, 2011 compared to historical data for the twelve months ended September 30, 2010 and the twelve months ended December 31, 2009.

	Twelve Months Ending		
	December 31, 2009	September 30, 2010	December 31, 2011 (Estimated)
Plant natural gas inlet, MMcf/d	581.9	579.2	660.3
Gross NGL Production, MBbl/d	69.8	69.9	80.2
Operating margin, $ in millions	$ 183.2	$ 236.6	$ 245.6

We forecast plant inlet volumes will increase by 14.0% for the twelve months ending December 31, 2011 as compared to the twelve months ended September 30, 2010 based on expected producer drilling and workover activity. New drilling is expected to come from liquids rich hydrocarbons plays including the Wolfberry Trend and Canyon Sands plays, which can be accessed by SAOU, the Wolfberry and Bone Springs plays, which can be accessed by the Sand Hills system, and the Barnett Shale and Fort Worth Basin, including Montague, Cooke, Clay and Wise counties, which can be accessed by the North Texas system.

Operating margin increased 29% from 2009 to the twelve months ended September 30, 2010 primarily as a result of higher commodity prices. Operating margin is estimated to increase by 3.8% to $245.6 million for the twelve months ending December 31, 2011 as compared to $236.6 million for the twelve months ended September 30, 2010 due to increases in plant inlet volumes partially offset by increased operating expenses and lower NGL prices.

Coastal Gathering and Processing Segment Assumptions. The following table summarizes selected operating and financial data for the Partnership for the twelve months ending December 31, 2011 compared to historical data for the twelve months ended September 30, 2010 and the twelve months ended December 31, 2009.

	Twelve Months Ending		
	December 31, 2009	September 30, 2010	December 31, 2011 (Estimated)
Plant natural gas inlet, MMcf/d	1,557.8	1,709.3	1,810.0
Gross NGL Production, MBbl/d	48.5	51.2	58.2
Operating margin, $ in millions	$ 89.7	$ 111.6	$ 102.0

Plant inlet volumes increased by 10% for the twelve months ended September 30, 2010 as compared to full year 2009 as a result of the recovery from the impacts of hurricanes in 2008. Plant inlet volumes are forecasted to increase 6% for the twelve months ending December 31, 2011 as compared to the twelve months ended September 30, 2010 based on the addition of new supply to our VESCO system primarily from anticipated additional production from existing customers.

Operating margin is estimated to be $102.0 million for the twelve months ending December 31, 2011 as compared to $111.6 million for the twelve months ended September 30, 2010. The decrease in operating margin is primarily attributable to lower margins resulting from lower forecasted liquids prices and higher forecasted natural gas prices and leaner inlet gas partially offset by forecasted increases in VESCO volumes.

NGL Logistics and Marketing. The Partnership s NGL Logistics and Marketing segment includes all 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, terminalling, 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 Logistics Assets segment uses its platform of integrated assets to store, fractionate, treat and transport NGLs, typically under fee-based and margin-based arrangements. 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.

Logistics Assets Segment Assumptions. The following table summarizes selected operating and financial data for the Partnership for the twelve months ending December 31, 2011 compared to pro forma historical data for the twelve months ended September 30, 2010 and the twelve months ended December 31, 2009.

	Twelve Months Ending		
	December 31, 2009	September 30, 2010	December 31, 2011 (Estimated)
Fractionation volumes, MBbl/d	217.2	221.4	291.6

Treating volumes, MBbl/d		21.9		21.4		27.5
Operating margin, $ in millions	$	74.4	$	79.8	$	118.6

Fractionation and treating volumes for 2011 are forecasted to increase approximately 31% relative to the twelve months ended September 30, 2010 primarily due to the 78 MBbl/d CBF expansion, which is expected to be in-service in the second quarter of 2011, and to the Mt. Belvieu Benzene treater, which is expected to be in-service in the fourth quarter of 2011.

Operating margin is estimated to increase approximately 49% to $118.6 million for 2011 as compared to $79.8 million for the twelve months ended September 30, 2010. This estimated increase is due to the higher fractionation and treating volumes; renewal of existing contracts at higher rates; the incremental price impact of the new contracts for the CBF expansion and the partial year impact of the Benzene treater described under Business of Targa Resources Partners LP Partnership Growth Drivers.

Marketing and Distribution Segment Assumptions. The following table summarizes selected operating and financial data for the Partnership for the twelve months ending December 31, 2011 compared to historical data for the twelve months ended September 30, 2010 and the twelve months ended December 31, 2009.

	Twelve Months Ending		
	December 31, 2009	September 30, 2010	December 31, 2011 (Estimated)
NGL Sales, MBbl/d	276.1	246.1	254.9
Operating margin, $ in millions	$ 82.9	$ 78.1	$ 65.6

The decline in volumes from the year ended December 31, 2009 to the twelve months ended September 30, 2010 was the result of a contract renegotiation which resulted in lower volumes but higher per barrel margins. We expect volumes in 2011 to increase slightly over volumes for the twelve months ended September 30, 2010 primarily due to some refinery outages in 2010 that reduced our supply of NGLs.

Operating margin is estimated to be $65.6 million for the twelve months ending December 31, 2011 which represents a $12.5 million decline from the twelve months ended September 30, 2010. The decrease is primarily due to lower expected margins on the sales of inventories. The Marketing and Distribution segment benefitted from a generally rising pricing environment that produced gains from sales of inventory over the twelve month periods ended September 30, 2010 and December 31, 2009.

Other. Other primarily reflects our hedge settlements which are the cash receipts or payments due to market prices settling above or below the prices of our hedging instruments. Contribution to operating margin from other decreased from $46.2 million for the twelve months ended December 31, 2009 to $16.7 million for the twelve months ended September 30, 2010 and is estimated to decrease further to $12.5 million for the twelve months ending December 31, 2011. The decrease from 2009 through the forecast period is primarily due to a trend of lower hedged volumes and higher commodity prices which result in lower cash settlements.

Other Assumptions

Depreciation and Amortization Expenses. The Partnership s depreciation and amortization expenses are estimated to be $175.4 million for the twelve months ending December 31, 2011, as compared to $170.1 million for the twelve months ended September 30, 2010. Depreciation and amortization is expected to increase as a result of the Partnership s organic growth projects and maintenance capital expenditures.

General and Administrative Expenses. The Partnership s general and administrative expenses include its public company expenses and are estimated to be $110.3 million for the twelve months ending December 31, 2011, as compared to $116.6 million for the twelve months ended September 30, 2010. General and administrative expenses are expected to decrease as a result of lower estimated compensation expense and decreased professional services associated with 2010 transactions.

Interest Expense. The Partnership s interest expense is estimated to be $110.3 million for the twelve months ending December 31, 2011. This amount includes (i) $63.0 million of interest expense related to the $690 million of senior unsecured notes with a weighted average interest rate of approximately 9.1%, (ii) $39.0 million of interest expense, after giving effect to the impact of interest rate hedges, under the

Partnership s revolving credit facility, at an assumed interest rate of approximately 3.8% (based on a 1% LIBOR plus a spread of 2.75%) and (iii) $8.3 million of commitment fees, amortization of debt issuance costs and letter of credit fees. Pro forma as adjusted for the Versado acquisition, the VESCO acquisition and the Partnership s debt and equity offerings in August 2010, the Partnership s revolving credit facility had a balance of $753.3 million on September 30, 2010. The balance is estimated to be $778.3 million at December 31, 2010 with the increase attributable to expansion capital expenditures. During the twelve month period ending December 31, 2011, we estimate that the Partnership will borrow $129.0 million to fund growth capital expenditures. After giving effect to LIBOR swaps for $300 million of the Partnership s revolving credit facility, a 1.0% change in LIBOR would result in a change in interest for the forecast period of $5.4 million.

Equity in Earnings of Unconsolidated Investment. The Partnership s equity in earnings of unconsolidated investment is estimated to be $11.5 million for the twelve months ending December 31, 2011, compared to $5.6 million for the twelve months ended September 30, 2010. The Partnership s equity in earnings of unconsolidated investment is related to its investment in GCF, and the increase is attributable to price increases for fractionation services.

Noncontrolling Interest Adjustment. Net income attributable to noncontrolling interest is estimated to be $31.2 million for the twelve months ending December 31, 2011, compared to $25.5 million for the twelve months ended September 30, 2010. Net income attributable to noncontrolling interest is associated with minority ownership stakes in Versado, VESCO and CBF. In the reconciliation of Partnership net income to Partnership Adjusted EBITDA, the non-controlling interest adjustment reflects depreciation expense attributable to the minority ownership stake.

Expansion Capital Expenditures, net and investments. The Partnership s forecasted expansion capital expenditures for the twelve months ending December 31, 2011 are estimated to be approximately $129.0 million net of minority partnership share and primarily consist of the benzene treating project, the expansions of CBF and GCF and various gathering and processing system expansions. See Business of Targa Resources Partners LP Partnership Growth Drivers. These forecasted capital expenditures are expected to be funded from borrowings under its revolving credit facility.

Maintenance Capital Expenditures, net. The Partnership s maintenance capital expenditures for the twelve months ending December 31, 2011 are estimated to be approximately $49.7 million, net of minority interest share, compared to $40.4 million on a pro forma basis for the twelve months ended September 30, 2010. These capital expenditures are expected to fund the development of additional gathering and processing capacity in areas in which producers have increased drilling activity. The estimated amount excludes approximately $8 million of capital expenditures associated with the Versado System that will be reimbursed to the Partnership by us. See Assumptions for Targa Resources Corp. Capital Expenditure Reimbursement to the Partnership.

Compliance with Debt Agreements. We expect that we and the Partnership will remain in compliance with the financial covenants in our respective financing arrangements.

Regulatory and Other. We have assumed that there will not be any new federal, state or local regulation of portions of the energy industry in which we and the Partnership operate, or a new interpretation of existing regulation, that will be materially adverse to our or the Partnership s business and market, regulatory, insurance and overall economic conditions will not change substantially.

Assumptions for Targa Resources Corp.

Financing and Interest Expense. We assume that our Holdco loan will have an average balance of approximately $85.0 million during 2011. Pursuant to the terms of such loan, we pay interest either in cash or in kind (PIK). We have assumed the cash pay option of LIBOR plus a margin of 3%.

Interest Income. We estimate that we will invest in a combination of cash and equivalents, treasuries and liquid, investment grade securities until which time the cash is necessary to satisfy these obligations. For the twelve months ending December 31, 2011 we estimate such investments will earn an average return of 2%.

Cash Taxes. We estimate that we will pay approximately $14.3 million in taxes for the twelve months ending December 31, 2011. This amount consists of $16.9 million from tax liabilities, which resulted from deferred gains for previous drop down transactions, partially offset by taxable losses that reduce taxes by $2.6 million. The $14.3 million of cash taxes due will be funded from our cash reserve, discussed further below.

Capital Expenditure Reimbursement to the Partnership. In connection with the sale of our interests in Versado to the Partnership, we have agreed to reimburse the Partnership for an estimated $19 million of capital expenditures which are expected to be paid by the end of 2011 from our cash reserve, discussed further below.

Cash Reserve. We estimate that at the closing of this offering we will have approximately $151 million of cash which will be sufficient to pay current payables as well as a $19 million capital expenditure reimbursement to be paid to the Partnership by the end of 2011 and $88 million of cash taxes which resulted from deferred gains from previous drop down transactions and which will be paid over the next ten years. We expect this cash balance, interest income earned on this balance over time, and any retained cash resulting from reserves established by our board of directors will be sufficient to satisfy these obligations.

TRC Minimum Estimated Cash Available for Distribution for the Three Month Period Ending December 31, 2010

Set forth below is a forecast of the TRC Minimum Estimated Cash Available for Distribution that supports our belief that we expect to generate sufficient cash flow to pay a quarterly dividend of $0.2575 per common share on all of our outstanding common shares for the three months ending December 31, 2010. We expect to pay a prorated dividend for the portion of the fourth quarter of 2010 that we are public. We believe our actual results of operations and cash flows for the three months ending December 31, 2010 will be sufficient to generate our minimum estimated cash available for distribution for such period; however, we can give you no assurance that such minimum estimated cash available for distribution will be achieved. There will likely be differences between our minimum estimated cash available for distribution for the three months ending December 31, 2010 and our actual results for such period and those differences could be material. If we fail to generate the minimum estimated cash available for distribution for the three months ending December 31, 2010, we may not be able to pay a prorated cash dividend on our common shares at the initial dividend rate stated in our cash dividend policy for such period.

This forward-looking financial information included in this prospectus has been prepared by, and is the responsibility of, our management. PricewaterhouseCoopers LLP has neither examined, compiled nor performed any procedures with respect to the accompanying forward-looking financial information and, accordingly, PricewaterhouseCoopers LLP does not express an opinion or any other form of assurance with respect thereto. The PricewaterhouseCoopers LLP reports included in this prospectus relate to our historical financial information. Such reports do not extend to this forward-looking financial information of the Partnership or us and should not be read to do so. Please see TRC Minimum Estimated Cash Available for Distribution for the Twelve Month Period Ending December 31, 2011

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above for cautionary statements and a discussion of risks and uncertainties relating to the three month forecast set forth below.

TRC Minimum Estimated Cash Available for Distribution for the Three Month Period Ending December 31, 2010

	Three Months Ending December 31, 2010 (In millions, except for share amounts)
Targa Resources Partners LP Data	
Revenues	$ 1,532.6
Less: Product purchases	(1,320.6)
Gross margin[(1)]	212.0
Less: Operating expenses	(70.5)
Operating margin[(2)]	141.5
Less:	
Depreciation and amortization expenses	(43.3)
General and administrative expenses	(32.6)
Income from operations	65.6
Plus (less): other income (expense)	
Interest expense, net	(25.7)
Equity in earnings of unconsolidated investment	1.6
Income before income tax	41.5
Less: income tax expense	(1.3)
Net income	40.2
Less: net income attributable to noncontrolling interest[(3)]	(6.5)
Net income attributable to Targa Resources Partners LP	$ 33.7
Plus:	
Interest expense, net	25.7
Income tax expense	1.3
Depreciation and amortization expenses	43.3
Noncash loss related to derivative instruments	7.4
Noncontrolling interest adjustment	(2.7)
Estimated Adjusted EBITDA[(4)]	$ 108.7
Less:	
Interest expense, net	(25.7)
Expansion capital expenditures, net	(41.2)
Borrowings for expansion capital expenditures	41.2
Maintenance capital expenditures, net	(20.0)

Amortization of debt issue costs		1.5
Cash reserve[5]		(16.8)
Estimated minimum cash available for distribution[6]	$	47.7
Partnership s debt covenant ratios[7]		
Interest coverage ratio of not less than 2.25 to 1.0		3.5x
Consolidated leverage ratio of not greater than 5.5 to 1.0		3.8x
Consolidated senior leverage ratio of not greater than 4.0 to 1.0		2.1x

		Three Months Ending December 31, 2010 (In millions, except for share amounts)
Estimated minimum cash available for distribution to Partnership unitholders		
Estimated minimum cash distributions to us:		
2% general partner interest	$	1.0
Incentive distribution rights[(8)]		5.3
Common units		6.4
Total estimated minimum cash distributions to us		12.7
Estimated minimum cash distributions to public unitholders		35.0
Total estimated minimum cash distributions by the Partnership	$	47.7

		Three Months Ending December 31, 2010 (In millions, except for share amounts)
Targa Resources Corp. Data[(9)(10)]		
Estimated minimum cash distributions to be received from the Partnership	$	12.7
Corporate general and administrative expenses		(1.4)
Partnership distributions less general and administrative expenses		11.3
Plus / (Less):		
Interest Expense		(0.8)
Interest Income		0.4
Cash taxes paid		(3.2)
Cash taxes funded from cash on hand		3.2
Minimum cash available for distribution		10.9
Expected dividend per share Quarterly[(11)]	$	0.2575
Total estimated dividends paid to stockholders (before proration)[(11)]	$	10.9

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

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

3. Reflects net income attributable to Chevron s 37% interest in Versado, Enterprise s 12% interest in VESCO, ONEOK s 11% interest in VESCO and BP s 12% interest in CBF.

4. Adjusted EBITDA is presented because we believe it provides additional information with respect to both the performance of our fundamental business activities as well as our ability to meet future debt service, capital expenditures and working capital requirements. It is a non-GAAP financial measure and is not intended to be used in lieu of the GAAP presentation of net income.

5. Represents a discretionary cash reserve. See The Partnership s Cash Distribution Policy.

6. The Partnership s estimated minimum cash available for distribution is presented because we believe it is used by investors to evaluate the ability of the Partnership to make quarterly cash distributions. It is a non-GAAP financial measure and is not intended to be used in lieu of the GAAP presentation of net income.

7. The Partnership s credit agreement and indentures contain certain financial covenants. The Partnership s revolving credit facility requires that, at the end of each fiscal quarter, the Partnership must maintain:

   an interest coverage ratio, defined as the ratio of the Partnership s consolidated adjusted EBITDA (as defined in the Amended and Restated Credit Agreement) for the four consecutive fiscal quarters most recently ended to the consolidated interest expense (as defined in the Amended and Restated Credit Agreement) for such period, of no less than 2.25 to 1.0;

   a Consolidated Leverage Ratio, defined as the ratio of the Partnership s consolidated funded indebtedness (as defined in the Amended and Restated Credit Agreement) to consolidated adjusted EBITDA, for the four fiscal quarters most recently ended, that is not greater than 5.5 to 1.0; and

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a Consolidated Senior Leverage ratio, defined as the ratio of the Partnership s consolidated funded indebtedness, excluding unsecured note indebtedness, to consolidated adjusted EBITDA, for the four fiscal quarters most recently ended, that is not greater than 4.0 to 1.0.

In addition, the indentures relating to the Partnership s existing senior notes require that the Partnership have a fixed charge coverage ratio for the most recently ended four fiscal quarters of not less than 1.75 to 1.0 in order to make distributions, subject to certain exceptions. This ratio is approximately equal to the interest coverage ratio described above. As indicated by the table, we estimate that the Partnership s pro forma EBITDA would be sufficient to permit cash distributions, under the terms of its credit agreement and indentures.

8. Based on the Partnership s 75,545,409 outstanding common units as of November 1, 2010 and the Partnership s fourth quarter 2010 quarterly distribution of $0.5475 per unit, or $2.19 per unit on an annualized basis, that management plans to recommend to the General Partner s board of directors.

9. We expect that we will have no debt outstanding under TRI s revolving credit facility, and accordingly, we have not presented credit ratios for this facility in the table. Pursuant to the terms of this facility at the end of each fiscal quarter, TRI must maintain:

   an interest coverage ratio, defined as the ratio of our consolidated adjusted EBITDA (as defined in the revolving credit agreement) for the four consecutive fiscal quarters most recently ended to the consolidated interest expense (as defined in the revolving credit agreement) for such period, of no less than 1.5 to 1.0;

   a Consolidated Leverage Ratio, defined as the ratio of our consolidated funded indebtedness (as defined in the revolving credit agreement) to consolidated adjusted EBITDA, for the four fiscal quarters most recently ended, that is not greater than 5.75 to 1.0 and becomes more restrictive over time.

10. The Holdco Loan agreement has no restrictive covenants which would impact our ability to pay dividends.

11. We expect to pay a prorated divided for the portion of the fourth quarter of 2010 that we are public. We estimate that we will have sufficient cash available to pay the full amount of the dividend and, therefore, any prorated portion thereof.

Assumptions and Considerations

We estimate that our ownership interests in the Partnership will generate sufficient cash flow to enable us to pay our initial quarterly dividend of $0.2575 per share, which will be prorated for the post-offering period, on all of our shares for the quarter ending December 31, 2010. Our ability to make this dividend payment assumes that the Partnership will pay its quarterly distribution of $0.5475 per common unit that management plans to recommend to the General Partner s board of directors for the fourth quarter ending December 31, 2010, which means that the total amount of cash distributions we will receive from the Partnership for that period would be $12.7 million.

The primary determinant in the Partnership s ability to pay a distribution of $0.5475 per common unit for the fourth quarter ending December 31, 2010, after giving effect to a $16.8 million cash reserve, is its ability to generate Adjusted EBITDA of at least $108.7 million during the period, which in turn is dependent on its ability to generate operating margin of $141.5 million.

The estimates of the Adjusted EBITDA and operating margin to be generated by the Partnership for the fourth quarter ending December 31, 2010 assumes the following volume and commodity price information:

	Three Months Ended December 31, 2010 (Estimated)
Field Plant Natural Gas Inlet, MMcf/d	596.7
Coastal Plant Natural Gas Inlet, MMcf/d	1,633.6
Logistics Fractionation, MBbl/d	250.1

		Three Months Ended December 31, 2010 (Estimated)
Natural Gas	$	3.67/MMBtu
Ethane	$	0.64/gallon
Propane	$	1.26/gallon
Isobutane	$	1.61/gallon
Normal Butane	$	1.57/gallon
Natural Gasoline	$	1.96/gallon
Crude Oil	$	80.34/Bbl

Other Assumptions

Volume assumptions. Field Gathering and Processing volumes reflect the impact of continued growth from increased drilling activity. Coastal Gathering and Processing daily volumes decline slightly as compared to the twelve months ended September 30, 2010 due primarily to temporary pipeline interruptions. Fractionation volumes reflect the stable demand for fractionating services. The volumes for each of these segments is set forth in the table above.

Commodity price assumptions. Commodity prices are based on actual prices for October 2010 and market prices as of November 4, 2010 for the remainder of the quarter.

General and Administrative Expenses. The Partnership s general and administrative expenses include its public company expenses and are estimated to be $32.6 million for the three months ending December 31, 2010. The general and administrative expense for the three months ending December 31, 2010 is higher than the quarterly average for the twelve months ended September 30, 2010 due to increased compensation costs and drop down transaction costs.

Interest Expense. The Partnership s interest expense is estimated to be $25.7 million for the three months ending December 31, 2010. This amount is based on the Partnership s outstanding senior unsecured notes and September 30, 2010 balance on the Partnership s revolving credit facility and gives effect to expansion capital expenditures funded during the three months ending December 31, 2010.

Expansion Capital Expenditures, net. The Partnership s forecasted expansion capital expenditures for the three months ending December 31, 2010 are estimated to be approximately $41.2 million, net of minority partnership share, and primarily consist of expenditures on previously announced expansion projects.

Maintenance Capital Expenditures, net. The Partnership s maintenance capital expenditures for the three months ending December 31, 2010 are estimated to be approximately $20.0 million, net of minority interest share. These capital expenditures are expected to fund the development of additional gathering and processing capacity in areas in which producers have increased drilling activity.

TRC Assumptions

General and Administrative Expense. We have assumed one quarter of the $5.4 million of the general and administrative expense estimated for the twelve months ending December 31, 2011.

Interest Expense. We assume that our Holdco loan will have an average balance of approximately $85 million for the three months ending December 31, 2010. Pursuant to the terms of such loan, we can pay interest either in cash or in kind (PIK). We have assumed the cash pay option of LIBOR plus a margin of 3%.

Interest Income. We estimate that we will invest in a combination of cash and cash equivalents, treasuries and liquid, investment grade securities. For the three months ending December 31, 2010 we estimate such investments will earn an average return of 2%.

Cash Taxes. We estimate that we will pay approximately $3.2 million in taxes for the three months ending December 31, 2010. This amount consists of $3.7 million of tax liabilities, resulting from deferred gains for previous drop down transactions, partially offset by taxable losses that reduce taxes by $0.5 million. The $3.2 million of cash taxes due will be funded from our cash reserve.

Cash Reserve. We estimate that at the closing of this offering we will have approximately $151 million of cash on hand which will be sufficient to pay $3.2 million of taxes for the three months ending December 31, 2010.

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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, 2007, 2008 and 2009 and selected historical consolidated balance sheet data as of December 31, 2009 and 2008 have been derived from our audited financial statements, included elsewhere in this prospectus. The selected historical consolidated statement of operations and cash flow data for the nine months ended September 30, 2009 and 2010 and the selected historical consolidated balance sheet data as of September 30, 2010 have been derived from our unaudited financial statements, included elsewhere in this prospectus.

The selected historical consolidated statement of operations and cash flow data for the years ended December 31, 2005 and 2006 and the selected historical consolidated balance sheet data as of December 31, 2005, 2006 and 2007 have been derived from our audited financial statements, which are not included in this prospectus. The selected historical consolidated balance sheet data as of September 30, 2009 has been derived from our unaudited financial statements, which are not included in this prospectus.

We derived the information in the following table from, 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.

	Year Ended December 31,					Nine Months Ended September 30,	
	2005	2006	2007	2008	2009	2009	2010
	(In millions, except operating and price data)						
Consolidated Statement of Operations Data:							
Revenues[1]	$ 1,829.0	$ 6,132.9	$ 7,297.2	$ 7,998.9	$ 4,536.0	$ 3,145.0	$ 3,942.0
Costs and expenses:							
Product purchases	1,632.0	5,440.8	6,525.5	7,218.5	3,791.1	2,624.9	3,387.6
Operating expenses	53.4	222.8	247.1	275.2	235.0	182.7	190.4
Depreciation and amortization expenses	27.1	149.7	148.1	160.9	170.3	127.9	136.9
General and administrative expenses	29.1	82.5	96.3	96.4	120.4	83.6	81.0
Other			(0.1)	13.4	2.0	1.8	(0.4)
Total costs and expenses	1,741.6	5,895.8	7,016.9	7,764.4	4,318.8	3,020.9	3,795.5
Income from operations	87.4	237.1	280.3	234.5	217.2	124.1	146.5
Other income (expense):							

Interest expense, net	(39.8)	(180.2)	(162.3)	(141.2)	(132.1)	(102.8)	(83.9)
Equity in earnings of unconsolidated investments	(3.8)	10.0	10.1	14.0	5.0	3.2	3.8
Gain (loss) on debt repurchases				25.6	(1.5)	(1.5)	(17.4)
Gain (loss) on early debt extinguishment	(3.3)			3.6	9.7	10.4	8.1
Gain on insurance claims				18.5			
Gain (loss) on mark-to-market derivative instruments	(74.0)			(1.3)	0.3	0.8	(0.4)
Other income	18.0				1.2	1.6	0.8
Income (loss) before income taxes	(15.5)	66.9	128.1	153.7	99.8	35.8	57.5
Income tax (expense) benefit	7.0	(16.7)	(23.9)	(19.3)	(20.7)	(5.1)	(18.5)
Net income (loss)	(8.5)	50.2	104.2	134.4	79.1	30.7	39.0
Less: Net income attributable to non controlling interest	7.3	26.0	48.1	97.1	49.8	17.7	46.2

	Year Ended December 31, 2005	2006	2007	2008	2009	Nine Months Ended September 30, 2009	2010
	(In millions, except operating and price data)						
Net income (loss) attributable to Targa Resources Corp.	(15.8)	24.2	56.1	37.3	29.3	13.0	(7.2)
Dividends on Series A preferred stock	(7.2)						
Conversion of Series A preferred stock to Series B preferred stock	(158.4)						
Dividends on Series B preferred stock	(6.5)	(39.7)	(31.6)	(16.8)	(17.8)	(13.2)	(8.4)
Undistributed earnings attributable to preferred shareholders[2]			(24.5)	(20.5)	(11.5)		
Distributions to common equivalents shareholders							(177.8)
Net income (loss) available to common shareholders	(187.9)	(15.5)				(0.2)	(193.4)
Net income (loss) per share basic and diluted	$ (80.64)	$ (2.53)	$	$	$	$ (0.03)	$ (21.51)
Financial data:							
Gross margin[3]	$ 197.0	$ 692.1	$ 771.7	$ 780.4	$ 744.9	$ 520.1	$ 554.4
Operating margin[4]	143.6	469.3	524.6	505.2	509.9	337.4	364.0
Operating data:							
Plant natural gas inlet, MMcf/d[5], [6]	400.8	1,863.3	1,982.8	1,846.4	2,139.8	2,097.7	2,296.5
Gross NGL production, MBbl/d	31.8	106.8	106.6	101.9	118.3	117.1	120.8
Natural gas sales, Bbtu/d[6]	313.5	501.2	526.5	532.1	598.4	590.4	678.4
NGL sales, MBbl/d	58.2	300.2	320.8	286.9	279.7	285.1	246.0
Condensate sales, MBbl/d	1.6	3.8	3.9	3.8	4.7	4.8	3.6
Average realized prices[7]:							
Natural gas, $/MMBtu	8.45	6.79	6.56	8.20	3.96	3.78	4.61
NGL, $/gal	0.84	1.02	1.18	1.38	0.79	0.71	1.03

Condensate, $/Bbl	55.17	63.67	70.01	91.28	56.31	54.36	73.42
Balance Sheet Data (at period end):							
Property plant and equipment, net	$ 2,436.6	$ 2,464.5	$ 2,430.1	$ 2,617.4	$ 2,548.1	$ 2,563.9	$ 2,494.9
Total assets	3,396.3	3,458.0	3,795.1	3,641.8	3,367.5	3,273.0	3,460.0
Long-term debt, less current maturities	2,184.4	1,471.9	1,867.8	1,976.5	1,593.5	1,622.6	1,663.4
Convertible cumulative participating Series B preferred stock	647.5	687.2	273.8	290.6	308.4	303.8	96.8
Total owners equity	(102.0)	(71.5)	574.1	822.0	754.9	789.9	994.3
Cash Flow Data:							
Net cash provided by (used in):							
Operating activities	$ 108.1	$ 269.5	$ 190.6	$ 390.7	$ 335.8	$ 202.9	$ 104.0
Investing activities	(2,328.1)	(117.8)	(95.9)	(206.7)	(59.3)	(50.7)	(81.8)
Financing activities	2,250.6	(50.4)	(59.5)	0.9	(386.9)	(327.1)	75.4

(1) Includes business interruption insurance proceeds of $3.0 million and $7.9 million for the nine months ended September 30, 2010 and 2009 and $21.5 million, $32.9 million, $7.3 million and $10.7 million for the years ended December 31, 2009, 2008, 2007 and 2006.

(2) Based on the terms of the preferred convertible stock, undistributed earnings of the Company are allocated to the preferred stock until the carrying value has been recovered.

(3) 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.

(4) 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.

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

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

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

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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 and pro forma 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 and pro forma 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

Because we control the General Partner, we reflect our ownership interest in the Partnership on a consolidated basis, which means that our financial results are combined with the Partnership s financial results in our consolidated financial statements. The limited partner interests in the Partnership not owned by controlled affiliates of us are reflected in our results of operations as net income attributable to non-controlling interests. We currently have no separate operating activities apart from those conducted by the Partnership, and our cash inflows consist of cash distributions from our interests in the Partnership. Throughout this discussion, when we refer to our financial results or our operations, we are referring to the financial results and operations of all of our consolidated subsidiaries, including the Partnership. Our consolidated financial statements differ from the results of operations of the Partnership due to non-controlling interests in the Partnership, and the effects of certain assets, liabilities and insurance recoveries that were retained by us and not included in our asset conveyances with the Partnership. The historical results of operations do not reflect incremental general and administrative expenses of $1.0 million that we expect to incur as a result of being a public company.

General

We are the sole member of Targa Resources GP LLC, which is the general partner of the Partnership. Through our control of the Partnership, we are a leading provider of midstream natural gas and NGL services in the United States. We are engaged in the business of gathering, compressing, treating, processing and selling natural gas and storing, fractionating, treating, transporting and selling NGLs and NGL products. We operate through two divisions: the Natural Gas Gathering and Processing division and the NGL Logistics and Marketing division. Our interests in the Partnership consist of the following:

- a 2% general partner interest, which we hold through our 100% ownership interest in the general partner of the Partnership;
- all Incentive Distribution Rights (IDRs); and
- 11,645,659 of the 75,545,409 outstanding common units of the Partnership, representing a 15.1% 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.

Cash Distributions

The following table sets forth the distributions that the Partnership has paid in respect of the 2% general partner interest, the associated IDRs and actual common units held during the periods indicated. 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.

			Actual Cash Distributions				
	Cash Distribution Per Limited Partner Unit	Limited Partner Units Outstanding	Total Partnership Cash Distributions	Distributions on Limited Partner Units	Distributions on General Partner Interest	Distributions on IDRs	Distributions to Targa Resources Corp.
	(In millions except and Cash Distribution 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

Recent Transactions

On July 19, 2010, the Partnership entered into an amended and restated five-year $1.1 billion senior secured revolving 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.

In August 2010, the Partnership completed a public offering of 7,475,000 common units and a separate private offering of $250,000,000 of 77/8% Senior Notes due 2018. The Partnership used the net proceeds from these offerings to reduce borrowings under its senior secured credit facility.

On August 25, 2010, the Partnership acquired from us a 63% ownership interest in Versado, a joint venture in which Chevron U.S.A. Inc. owns the remaining 37% interest, for a purchase price of $247.2 million. Versado owns a natural gas gathering and processing business consisting of the Eunice, Monument and Saunders gathering and processing systems, including treating operations, processing plants and related assets. The Versado System includes three refrigerated cryogenic processing plants and approximately 3,200 miles of combined gathering pipelines in Southeast New Mexico and West Texas and is primarily conducted under percent of proceeds arrangements. During 2009, the

Versado System processed an average of approximately 198.8 MMcf/d of natural gas and produced an average of approximately 22.2 MBbl/d of NGLs. In the first nine months of 2010, the Versado System processed an average of approximately 180.5 MMcf/d of natural gas and produced an average of approximately 20.4 MBbl/d of NGLs.

On September 28, 2010, the Partnership acquired from us an approximate 77% ownership interest in Venice Energy Services Company, L.L.C. (VESCO), a joint venture in which Enterprise Gas Processing, LLC and Oneok Vesco Holdings, L.L.C. own the remaining ownership interests, for a purchase price of $175.6 million. VESCO owns and operates a natural gas gathering and processing business in Louisiana

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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, the VESCO System). The VESCO System captures volumes from the Gulf of Mexico shelf and deepwater. For the year ended December 31, 2009 and for the nine months ended September 30, 2010, VESCO processed 363 MMcf/d and 423 MMcf/d of natural gas, respectively.

On October 8, 2010, the Partnership declared a quarterly cash distribution of $0.5375 per common unit, or $2.15 per common unit on an annualized basis, for the third quarter of 2010, payable on November 12, 2010 to holders of record on October 18, 2010.

On November 4, 2010, the Partnership announced that management plans to recommend to the General Partner s board of directors a $0.04 increase in the annualized cash distribution rate to $2.19 per common unit for the fourth quarter of 2010 distribution.

Factors That Significantly Affect Our Results

Upon completion of this offering, our only cash-generating assets will consist of our interests in the Partnership. Therefore, our cash flow and resulting ability to pay dividends will be dependent upon the Partnership s ability to make distributions in respect of those interests. The actual amount of cash that the Partnership will have available for distribution will depend primarily on the amount of cash it generates from operations.

Our results of operations are substantially impacted by the volumes that move through both our gathering and processing and our logistics assets, our contract terms and changes in commodity prices.

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

Contract Terms and Contract Mix and the Impact of Commodity Prices. Our natural gas gathering and processing contract arrangements can have a significant impact on our profitability. Because of the significant volatility of natural gas and NGL prices, the contract mix of our natural gas gathering and processing segment can have a significant impact on our profitability. Negotiated contract terms are based upon a variety of factors, including natural gas quality, geographic location, the competitive environment at the time the contract is executed and customer preferences. Contract mix and, accordingly, exposure to natural gas and NGL prices may change over time as a result of changes in these underlying factors.

Set forth below is a table summarizing the contract mix of our natural gas gathering and processing division for 2009 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	48%	Decreases in natural gas and or NGL prices generate decreases in operating margins
Fee-Based	11%	No direct impact from commodity price movements

Wellhead Purchases / Keep-Whole	18%	Decreases in NGL prices relative to natural gas prices generate decreases in operating margins
Hybrid	23%	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.

Actual 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. Our gathering and processing contract mix and, accordingly, our 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, our expansion into regions where different types of contracts are more common as well as other market factors. We prefer to enter into contracts with less commodity price sensitivity including fee-based and percent-of-proceeds arrangements.

The contract terms and contract mix of our downstream business have a significant impact on our 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 segment includes both fee based and percent of proceeds contracts.

We attempt to mitigate the impact of commodity prices on our results of operations through hedging activities which can materially impact our results of operations. See Quantitative and Qualitative Disclosures About Market Risk Commodity Price Risk. Because the Downstream Business is primarily fee based, our hedging activities are primarily focused on the equity volume positions associated with our percent-of-proceeds or percent-of-liquids gas processing contracts.

Impact of Our Hedging Activities. In an effort to reduce the variability of our cash flows, we have hedged the commodity price associated with a portion of our expected natural gas, NGL and condensate equity volumes for the remainder of 2010 through 2013 by entering into derivative financial instruments including swaps and purchased puts (or floors). With these arrangements, we have attempted to mitigate our exposure to commodity price movements with respect to our forecasted volumes for this period. For additional information regarding our hedging activities, see Quantitative and Qualitative Disclosures About Market Risk Commodity Price Risk.

General Trends and Outlook

We expect our business to continue to be affected by the following key trends. Our expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about or interpretations of available information prove to be incorrect, our actual results may vary materially from our expected results.

Demand for Our Services. Fluctuations in energy prices can affect production rates and investments by third parties in the development of oil and natural gas reserves. Generally, drilling and production activity will increase as energy prices increase. Although recent economic conditions negatively impacted overall commodity prices, we believe that the current strength of oil, condensate and NGL prices compared to natural gas prices has caused producers in and around our natural gas gathering and processing areas of operation to focus their drilling programs on regions rich in these forms of hydrocarbons. 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 over the next several years. Producer activity in areas rich in oil, condensate and NGLs is currently generating increased demand for our fractionation services and for related fee-based services provided by our downstream business. While we expect development activity to remain robust with respect to oil and liquids rich gas development and production, currently depressed natural gas prices have resulted in reduced activity levels surrounding comparatively dry natural gas reserves, whether conventional or unconventional.

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Significant Relationships. The following table lists the percentage of our consolidated sales and consolidated product purchases with our significant customers and suppliers:

	Year Ended December 31, 2007	2008	2009
% of consolidated revenues CPC	26%	19%	15%
% of consolidated product purchases Louis Dreyfus Energy Services L.P.	13%	9%	11%

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 November 2010 through October 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 our systems.

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

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

Increased Regulation. Additional regulation in various areas has the potential to materially impact our operations and financial condition. For example, if regulation of hydraulic fracturing used by producers increased, we may experience 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 our ability or increase the cost to use derivatives, which could create more volatility and less predictability in our results of operations. Please read Risk Factors The recent adoption of derivatives legislation by the United States Congress could have an adverse effect on the Partnership s ability to hedge risks associated with its business.

How We Evaluate Our Operations

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

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

Throughput Volumes, Facility Efficiencies and Fuel Consumption. Our profitability is impacted by our 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 our gathering and processing systems. This is achieved by connecting new wells and adding new volumes in existing areas of production as well as by capturing natural gas supplies currently gathered by third parties. Similarly, our profitability is impacted by our ability to add new sources of mixed NGL supply, typically connected by third party transportation, to our downstream fractionation facilities. We fractionate NGLs generated by our gathering and processing plants as well as by contracting for mixed NGL supply from third party gathering or fractionation facilities.

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

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

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

Gross Margin. With respect to our Natural Gas Gathering and Processing division, we define gross margin as total operating revenues, which consist of natural gas and NGL sales plus service fee revenues, less product purchases, which consist primarily of producer payments and other natural gas purchases. With respect to our Logistics Assets segment, we define gross margin as total revenue, which consists primarily of service fee revenue. With respect to our Marketing and Distribution segment, we define gross margin as total revenue, which consists primarily of service fee revenues and NGL sales, less cost of sales, which consists primarily of NGL purchases and changes in inventory valuation.

Operating Margin. We review performance based on operating margin. We define operating margin as revenues, which consist of natural gas and NGL sales plus service fee revenues, less product

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purchases, which consist primarily of producer payments and other natural gas purchases, and operating expenses. Natural gas and NGL sales revenue includes settlement gains and losses on commodity hedges. Our operating margin is impacted by volumes and commodity prices as well as by our contract mix and hedging program, which are described in more detail below. We view our operating margin as an important performance measure of the core profitability of our operations. We review our operating margin monthly for consistency and trend analysis.

The GAAP measure most directly comparable to gross margin and operating margin is net income. Gross margin and operating margin should not be considered as an alternative to GAAP net income. Gross margin and operating margin are not presentations made in accordance with GAAP and have important limitations as an analytical tool. 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.

We compensate for the limitations of gross margin and operating margin as an analytical tool by reviewing the comparable GAAP measure, understanding the differences between the measures and incorporating these insights into our decision-making processes.

	Year Ended December 31,					Nine Months Ended September 30,	
	2005	**2006**	**2007**	**2008**	**2009**	**2009**	**2010**
				(In millions)			
Reconciliation of gross margin and operating margin to net income attributable to Targa Resources Corp.:							
Gross margin	$ 197.0	$ 692.1	$ 771.7	$ 780.4	$ 744.9	$ 520.1	$ 554.4
Operating (expenses)	(53.4)	(222.8)	(247.1)	(275.2)	(235.0)	(182.7)	(190.4)
Operating margin	143.6	469.3	524.6	505.2	509.9	337.4	364.0
Net income attributable to noncontrolling interest	(7.3)	(26.0)	(48.1)	(97.1)	(49.8)	(17.7)	(46.2)
Depreciation and amortization expenses	(27.1)	(149.7)	(148.1)	(160.9)	(170.3)	(127.9)	(136.9)
General and administrative expenses	(29.1)	(82.5)	(96.3)	(96.4)	(120.4)	(83.6)	(81.0)
Interest expense, net	(39.8)	(180.2)	(162.3)	(141.2)	(132.1)	(102.8)	(83.9)
Gain (loss) on debt repurchase				25.6	(1.5)	(1.5)	(17.4)
Gain (loss) on early debt extinguishment	(3.3)			3.6	9.7	10.4	8.1
Income tax (expense) benefit	7.0	(16.7)	(23.9)	(19.3)	(20.7)	(5.1)	(18.5)
Other, net	(59.8)	10.0	10.2	17.8	4.5	3.8	4.6
Net income (loss) attributable to Targa Resources Corp.	$ (15.8)	$ 24.2	$ 56.1	$ 37.3	$ 29.3	$ 13.0	$ (7.2)

We believe that investors benefit from having access to the same financial measures that our management uses in evaluating our operating results. Operating margin provides useful information to investors because it is used as a supplemental financial measure by us and by external users of our financial statements, including such investors, commercial banks and others, to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- our operating performance and return on capital as compared to other companies in the midstream energy sector, without regard to financing or capital structure; and
- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

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Results of Operations

The following table and discussion is a summary of our consolidated results of operations for the nine months ended September 30, 2010 and 2009 and the three years ended December 31, 2009.

	Year Ended December 31,			Variance 2008 vs. 2007		Variance 2009 vs. 2008		Nine Months Ended Sept		
	2007	2008	2009	$ Change		$ Change		2009	2010	$ Char
	$ 7,297.2	$ 7,998.9	$ 4,536.0	$ 701.7	9.6%	$ (3,462.9)	(43.3)%	$ 3,145.0	$ 3,942.0	$ 79
	6,525.5	7,218.5	3,791.1	693.0	10.6%	(3,427.4)	(47.5)%	2,624.9	3,387.6	76
	771.7	780.4	744.9	8.7	1.1%	(35.5)	(4.5)%	520.1	554.4	3
s	247.1	275.2	235.0	28.1	11.4%	(40.2)	(14.6)%	182.7	190.4	
	148.1	160.9	170.3	12.8	8.6%	9.4	5.8%	127.9	136.9	
	96.3	96.4	120.4	0.1	0.1%	24.0	24.9%	83.6	81.0	(
	(0.1)	13.4	2.0	13.5	*	(11.4)	(85.1)%	1.8	(0.4)	(
	280.3	234.5	217.2	(45.8)	(16.3)%	(17.3)	(7.4)%	124.1	146.5	2
et	(162.3)	(141.2)	(132.1)	21.1	(13.0)%	9.1	(6.4)%	(102.8)	(83.9)	1
		18.5		18.5	*	(18.5)	(100.0)%			
	10.1	14.0	5.0	3.9	38.6%	(9.0)	(64.3)%	3.2	3.8	
		25.6	(1.5)	25.6	*	(27.1)	(105.9)%	(1.5)	(17.4)	(1
		3.6	9.7	3.6	*	6.1	169.4%	10.4	8.1	(
		(1.3)	0.3	(1.3)	*	1.6	(123.1)%	0.8	(0.4)	(
			1.2		*	1.2	*	1.6	0.8	(
e	(23.9)	(19.3)	(20.7)	4.6	(19.2)%	(1.4)	7.3%	(5.1)	(18.5)	(1

Exhibit 10.1 to Form 8-K

(Date
of
Report
March
29,
2010)
(“March
2010
Form
8-K”)
10(k-2)

Amendment to Continuity Agreements and Severance Agreements with Sheldon I. Cammaker, Anthony J. Guzzi, R. Kevin Matz and Mark A. Pompa

Exhibit 10(q) to EMCOR’s Annual Report on Form 10-K for the year ended December 31, 2008 (“2008 Form 10-K”)
10(l-1)

EMCOR Group, Inc. Long-Term Incentive Plan (“LTIP”)

Exhibit 10 to Form 8-K (Date of Report December 15, 2005
10(l-2)

First Amendment to LTIP and updated Schedule A to LTIP

Exhibit 10(s-2) to 2008 Form 10-K
10(l-3)

Second Amendment to LTIP

Exhibit 10.2 to March 2010 Form 8-K
10(l-4)

Third Amendment to LTIP

Exhibit 10(q-4) to EMCOR's Quarterly Report on Form 10-Q for the quarter ended March 31, 2012 ("March 2012 Form 10-Q")
10(l-5)

Fourth Amendment to LTIP

Filed herewith
10(l-6)

Form of Certificate Representing Stock Units issued under LTIP

Exhibit 10(t-2) to EMCOR’s Annual Report on Form 10-K for the year ended December 31, 2007 (“2007 Form 10-K”)
10(m-1)

2003 Non-Employee Directors’ Stock Option Plan

Exhibit A to EMCOR's Proxy Statement for its Annual Meeting held on June 12, 2003 ("2003 Proxy Statement")
10(m-2)

First Amendment to 2003 Non-Employee Directors' Plan

Exhibit 10(u-2) to EMCOR's Annual Report on Form 10-K for the year ended December 31, 2006 ("2006 Form 10-K")
10(n-1)

2003 Management Stock Incentive Plan

Exhibit B to EMCOR's 2003 Proxy Statement
10(n-2)

Amendments to 2003 Management Stock Incentive Plan

Exhibit 10(t-2) to EMCOR's Annual Report on Form 10-K for the year ended December 31, 2003 ("2003 Form 10-K")
10(n-3)

Second Amendment to 2003 Management Stock Incentive Plan

Exhibit 10(v-3) to 2006 Form 10-K
10(o)

Form of Stock Option Agreement evidencing grant of stock options under the 2003 Management Stock Incentive Plan

Exhibit 10.1 to Form 8-K (Date of Report January 3, 2005)
10(p)

Key Executive Incentive Bonus Plan

Exhibit B to EMCOR's Proxy Statement for its Annual Meeting held June 18, 2008 ("2008 Proxy Statement")
10(q)

Consents on December 15, 2009 to Transfer Stock Options by Non-Employee Directors

Exhibit 10(z) to 2009 Form 10-K
10(r)

Form of EMCOR Option Agreement for Executive Officers granted January 2, 2003 and January 2, 2004

Exhibit 4.7 to 2004 Form S-8
10(s)

Option Agreement dated October 25, 2004 between Guzzi and EMCOR

Exhibit A to Guzzi Letter
10(t-1)

2007 Incentive Plan

Exhibit B to EMCOR's Proxy Statement for its Annual Meeting held June 20, 2007

10(t-2)

Option Agreement dated December 13, 2007 under 2007 Incentive Plan between Jerry E. Ryan and EMCOR

Exhibit 10(h)(h-2) to 2007 Form 10-K
10(t-3)

Option Agreement dated December 15, 2008 under 2007 Incentive Plan between David Laidley and EMCOR

Exhibit 10.1 to Form 8-K (Date of Report December 15, 2008)

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EXHIBIT INDEX

Exhibit No.	Description	Incorporated By Reference to or Filed Herewith, as Indicated Below
10(t-4)	Form of Option Agreement under 2007 Incentive Plan between EMCOR and each non-employee director electing to receive options as part of annual retainer	Exhibit 10(h)(h-3) to 2007 Form 10-K
10(u-1)	2010 Incentive Plan	Exhibit B to EMCOR’s Proxy Statement for its Annual Meeting held on June 11, 2010
10(u-2)	Amendment No. 1 to 2010 Incentive Plan	Exhibit 10(f)(f-2) to EMCOR’s Annual Report on Form 10-K for the year ended December 31, 2011 (“2011 Form 10-K”)
10(u-3)	Amendment No. 2 to 2012 Incentive Plan	Exhibit 10(t-3) to 2012 Form 10-K
10(u-4)	Form of Option Agreement under 2010 Incentive Plan between EMCOR and each non-employee director with respect to grant of options upon re-election at June 11, 2010 Annual Meeting of Stockholders	Exhibit 10(i)(i-2) to EMCOR’s Quarterly Report on Form 10-Q for the quarter ended June 30, 2010
10(u-5)	Form of Option Agreement under 2010 Incentive Plan, as amended, between EMCOR and each non-employee director electing to receive options as part of annual retainer	Exhibit 10(q)(q) to 2011 Form 10-K
10(v)	Form of letter agreement between EMCOR and each Executive Officer with respect to acceleration of options granted January 2, 2003 and January 2, 2004	Exhibit 10(b)(b) to 2004 Form 10-K
10(w)	EMCOR Group, Inc. Employee Stock Purchase Plan	Exhibit C to EMCOR’s Proxy Statement for its Annual Meeting held June 18, 2008
10(x)	Form of Restricted Stock Award Agreement dated January 3, 2012 between EMCOR and each of Larry J. Bump, Albert Fried, Jr., Richard F. Hamm, Jr., David H. Laidley, Frank T. MacInnis, Jerry E. Ryan and Michael T. Yonker	Exhibit 10(m)(m) to 2011 Form 10-K
10(y-1)	Director Award Program Adopted May 13, 2011, as amended and restated December 14, 2011	Exhibit 10(n)(n) to 2011 Form 10-K
10(y-2)	Form of Amended and Restated Restricted Stock Award Agreement dated December 14, 2011 amending and restating restricted stock award agreement dated June 1, 2011 under Director Award Program with each of Stephen W. Bershad, David A.B. Brown, Larry J. Bump, Albert Fried, Jr., Richard F. Hamm, Jr., David H. Laidley, Jerry E. Ryan and Michael T. Yonker	Exhibit 10(o)(o) to 2011 Form 10-K
10(z)	Restricted Stock Unit Agreement dated May 9, 2011 between EMCOR and Anthony J. Guzzi	Exhibit 10(o)(o) to EMCOR’s Quarterly Report on Form 10-Q for the quarter ended September 30, 2011
10(a)(a)	Amendment to Option Agreements	Exhibit 10(r)(r) to 2011 Form 10-K

10(b)(b)	Form of Restricted Stock Unit Agreement dated March , 2012 between EMCOR and each of Sheldon I. Cammaker, R. Kevin Matz and Mark A. Pompa	Exhibit 10(o)(o) to the March 31, 2012 Form 10-Q
10(c)(c)	Form of Non-LTIP Stock Unit Certificate	Exhibit 10(p)(p) to the March 31, 2012 Form 10-Q
10(d)(d)	Form of Director Restricted Stock Unit Agreement	Exhibit 10(k)(k) to EMCOR's Quarterly Report on Form 10-Q for the quarter ended June 30, 2012 ("June 2012 Form 10-Q")
10(e)(e)	Director Award Program, as Amended and Restated December 6, 2012	Exhibit 10(d)(d) to 2012 Form 10-K
10(f)(f)	EMCOR Group, Inc. Voluntary Deferral Plan	Exhibit 10(e)(e) to 2012 Form 10-K
10(g)(g)	Form of Executive Restricted Stock Unit Agreement	Exhibit 10(f)(f) to 2012 Form 10-K
11	Computation of Basic EPS and Diluted EPS for the three and six months ended June 30, 2013 and 2012	Note 4 of the Notes to the Condensed Consolidated Financial Statements

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EXHIBIT INDEX

Exhibit No.	Description	Incorporated By Reference to or Filed Herewith, as Indicated Below
31.1	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 by Anthony J. Guzzi, the President and Chief Executive Officer	Filed herewith
31.2	Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 by Mark A. Pompa, the Executive Vice President and Chief Financial Officer	Filed herewith
32.1	Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 by the President and Chief Executive Officer	Furnished
32.2	Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 by the Executive Vice President and Chief Financial Officer	Furnished
95	Information concerning mine safety violations or other regulatory matters	Exhibit 95 to the June 2012 Form 10-Q
101	The following materials from EMCOR Group, Inc.'s Quarterly Report on Form 10-Q for the quarter ended June 30, 2013, formatted in XBRL (Extensible Business Reporting Language): (i) the Condensed Consolidated Balance Sheets, (ii) the Condensed Consolidated Statements of Operations, (iii) the Condensed Consolidated Statements of Comprehensive Income, (iv) the Condensed Consolidated Statements of Cash Flows, (v) the Condensed Consolidated Statements of Equity and (vi) the Notes to Condensed Consolidated Financial Statements.	Filed