Summit Midstream Partners, LP
Form 10-K
March 18, 2013
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K
(Mark One)
[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2012
or
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission file number: 001-35666
Summit Midstream Partners, LP
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	45-5200503 (I.R.S. Employer Identification No.)
2100 McKinney Avenue, Suite 1250 Dallas, Texas (Address of principal executive offices)	75201 (Zip Code)

Registrant's telephone number, including area code: (214) 242-1955

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

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
o Yes x No
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Securities Act.
o Yes x No
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. x Yes o No
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
x Yes o No
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer o	Accelerated Filer o
Non-Accelerated Filer x (Do not check if a smaller reporting company)	Smaller Reporting Company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). o Yes x No

The registrant completed its IPO in October 2012. As such, it cannot calculate the aggregate market value of its common units held by non-affiliates as of the last business day of its most recently completed second fiscal quarter because there was no established public trading market for its common units as of such date.

Indicate the number of shares outstanding of each of the issuer’s classes of common stock, as of the latest practicable date.

Class	As of February 28, 2013
Common Units	24,412,427 units
Subordinated Units	24,409,850 units
General Partner Units	996,320 units

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FORWARD-LOOKING STATEMENTS

Investors are cautioned that certain statements contained in this report as well as in periodic press releases and some oral statements made by our officials during our presentations are “forward-looking” statements. Forward-looking statements include, without limitation, any statement that may project, indicate or imply future results, events, performance or achievements, and may contain the words “expect,” “intend,” “plan,” “anticipate,” “estimate,” “believe,” “will “will continue,” “will likely result,” and similar expressions, or future conditional verbs such as “may,” “will,” “should,” “wou and “could.” In addition, any statement concerning future financial performance (including future revenues, earnings or growth rates), ongoing business strategies or prospects, and possible actions taken by us or our subsidiaries, are also forward-looking statements. These forward-looking statements involve external risks and uncertainties, including, but not limited to, those described under the section entitled “Risk Factors” included herein.

Forward-looking statements are based on current expectations and projections about future events and are inherently subject to a variety of risks and uncertainties, many of which are beyond the control of our management team. All forward-looking statements in this report and subsequent written and oral forward-looking statements attributable to us, or to persons acting on our behalf, are expressly qualified in their entirety by these risks and uncertainties. These risks and uncertainties include, among others:

- changes in general economic conditions;
- fluctuations in oil, natural gas and natural gas liquids prices;
- the extent and success of drilling efforts, as well as the extent and quality of natural gas volumes produced within proximity of our assets;
- failure or delays by our customers in achieving expected production in their natural gas projects;
- competitive conditions in our industry and their impact on our ability to connect natural gas supplies to our gathering and compression assets or systems;
- actions or inactions taken or non-performance by third parties, including suppliers, contractors, operators, processors, transporters and customers;
- our ability to consummate acquisitions, successfully integrate the acquired businesses, realize any cost savings and other synergies from any acquisition;
- the ability to attract and retain key management personnel;
- changes in the availability and cost of capital;
- the availability, terms and cost of downstream transportation services;
- operating hazards, natural disasters, accidents, weather-related delays, casualty losses and other matters beyond our control;
- timely receipt of necessary government approvals and permits, our ability to control the costs of construction, including costs of materials, labor and right-of-way and other factors that may impact our ability to complete projects within budget and on schedule;
- the effects of existing and future laws and governmental regulations, including environmental and climate change requirements;
- the effects of existing and future litigation; and
- certain factors discussed elsewhere in this report.

Developments in any of these areas could cause actual results to differ materially from those anticipated or projected or cause a significant reduction in the market price of our common units.

The foregoing list of risks and uncertainties may not contain all of the risks and uncertainties that could affect us. In addition, in light of these risks and uncertainties, the matters referred to in the forward-looking statements contained in this document may not in fact occur. Accordingly, undue reliance should not be placed on these statements. We undertake no obligation to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise, except as otherwise required by law.

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GLOSSARY OF TERMS

adjusted EBITDA: EBITDA plus non-cash compensation expense and adjustments related to minimum volume commitment shortfall payments
AMI: area of mutual interest
condensate: a natural gas liquid with a low vapor pressure, mainly composed of propane, butane, pentane and heavier hydrocarbon fractions
distributable cash flow: adjusted EBITDA plus cash interest income, less cash paid for interest expense and income taxes and maintenance capital expenditures
dry gas: a gas primarily composed of methane and ethane where heavy hydrocarbons and water either do not exist or have been removed through processing
EBITDA: net income, plus interest expense, income tax expense, and depreciation and amortization expense, less interest income and income tax benefit
end users: the ultimate users and consumers of transported energy products
Mcf: one thousand cubic feet
MMBtu: one million British Thermal Units
MMcf: one million cubic feet
MMcf/d: one million cubic feet per day
MVC: minimum volume commitment
NGLs: natural gas liquids; the combination of ethane, propane, normal butane, iso-butane and natural gasolines that when removed from natural gas become liquid under various levels of higher pressure and lower temperature
NYMEX: New York Mercantile Exchange
play: a proven geological formation that contains commercial amounts of hydrocarbons
receipt point: the point where production is received by or into a gathering system or transportation pipeline
residue gas: the natural gas remaining after being processed or treated
tailgate: refers to the point at which processed natural gas and NGLs leave a processing facility for end-use markets
Tcf: one trillion cubic feet
throughput volume: the volume of natural gas transported or passing through a pipeline, plant or other facility during a particular period
wellhead: the equipment at the surface of a well used to control the well's pressure; also, the point at which the hydrocarbons and water exit the ground

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PART I

Item 1. Business.

Summit Midstream Partners, LP ("SMLP") is a Delaware limited partnership that completed its initial public offering ("IPO") on October 3, 2012 to become a publicly traded entity. Summit Midstream Partners, LLC ("Summit Investments") is a Delaware limited liability company and the predecessor for accounting purposes (the "Predecessor") of SMLP. References to the "Company," "we," or "our," when used for dates or periods ended on or after the IPO, refer collectively to SMLP and its subsidiaries. References to the "Company," "we," or "our," when used for dates or periods ended prior to the IPO, refer collectively to Summit Investments and its subsidiaries. Immediately prior to the closing of the IPO, Summit Investments conveyed an interest in Summit Midstream Holdings, LLC ("Summit Holdings") to Summit Midstream GP, LLC (our "general partner") as a capital contribution; our general partner conveyed its interest in Summit Holdings to SMLP; and Summit Investments conveyed its remaining interest in Summit Holdings to SMLP. Therefore, the historical financial statements contained in this Form 10-K reflect the assets, liabilities and operations of Summit Investments (excluding the results of operations of assets outside of Summit Holdings that were retained by Summit Investments) for periods ending before October 3, 2012 and the assets, liabilities and operations of SMLP for periods beginning on or after October 3, 2012. References in this Form 10-K to "Energy Capital Partners" refer collectively to Energy Capital Partners II, LLC and its parallel and co-investment funds. References in this Form 10-K to "GE Energy Financial Services" refer collectively to GE Energy Financial Services, Inc. References in this Form 10-K to our "Sponsors" refer collectively to Energy Capital Partners and GE Energy Financial Services.

Overview

SMLP is a growth-oriented limited partnership focused on owning and operating midstream energy infrastructure assets that are strategically located in the core producing areas of unconventional resource basins, primarily shale formations, in North America. We provide natural gas gathering and compression services pursuant to long-term, fee-based natural gas gathering agreements with our customers. Our results are driven primarily by the volumes of natural gas that we gather and compress across our systems. During the year ended December 31, 2012, we generated approximately 90% of our revenue from fee-based gathering services that we provided to our customers. We currently operate in two unconventional resource basins:

- the Piceance Basin, which includes the Mesaverde formation and the Mancos and Niobrara shale formations in western Colorado; and
- the Fort Worth Basin, which includes the Barnett Shale formation in north-central Texas.

The Grand River system services our customers operating in the Piceance Basin and the DFW Midstream system services our customers operating in the Fort Worth Basin. As of December 31, 2012, these gathering systems had approximately 399 miles of pipeline and 147,600 horsepower of compression. During 2012, these systems gathered an average of approximately 929 MMcf/d of natural gas, of which approximately 62% was delivered to a third-party natural gas processing facility.

We generate a substantial majority of our revenue under long-term, fee-based natural gas gathering agreements with remaining terms that range from six years to 24 years. The fee-based nature of these agreements enhances the stability of our cash flows by limiting our direct commodity price exposure. Our customers include affiliates and/or subsidiaries of some of the largest natural gas producers in North America, such as:

- Bill Barrett Corporation ("Bill Barrett");
- Carrizo Oil & Gas, Inc. ("Carrizo");
- Chesapeake Energy Corporation ("Chesapeake");
- Encana Corporation ("Encana");
- EOG Resources, Inc. ("EOG");
- Exxon Mobil Corporation ("Exxon Mobil");
- TOTAL, S.A. ("TOTAL"); and
- WPX Energy, Inc. ("WPX Energy").

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A significant percentage of our revenue is attributable to three producer customers and one natural gas marketer. For the year ended December 31, 2012, customers that accounted for 10% or more of total revenues were Carrizo, Chesapeake and Encana.

Substantially all of our gas gathering agreements include areas of mutual interest ("AMIs"). Areas of mutual interest require that any production from natural gas wells drilled by our customers within the AMI be shipped on our gathering systems. Our AMIs cover approximately 330,000 acres in the aggregate and have remaining terms that range from six years to 24 years.

In addition, substantially all of our gas gatherings agreements include minimum volume commitments ("MVCs"). A minimum volume commitment contractually obligates our customers to ship a minimum quantity of natural gas or make payments to cover the shortfall of natural gas not shipped, either on a monthly or annual basis. We have designed our minimum volume commitment provisions to ensure that we will generate a certain amount of revenue from each customer over the life of the respective gas gathering agreement, whether by collecting gathering fees on actual throughput or from cash payments to cover any minimum volume commitment shortfall. As of December 31, 2012, we had remaining minimum volume commitments totaling 2.4 Tcf with original terms that range from seven years to 15 years. Our minimum volume commitments have a weighted-average remaining life of 11.1 years (assuming minimum throughput volume for the remainder of the term) and average approximately 629 MMcf/d through 2020.

We are positioned for growth through the increased utilization and further development of our existing gathering system assets. In addition, we intend to grow our business through strategic partnerships with large producers to provide midstream services for their upstream development projects. We also intend to expand our operations and diversify our geographic footprint through asset acquisitions from third parties and Summit Investments, although Summit Investments has no obligation to offer any assets to us in the future.

Our midstream assets currently consist of two natural gas gathering systems, the Grand River system in western Colorado and the DFW Midstream system in north-central Texas.

Grand River System

In October 2011, we acquired certain natural gas gathering pipeline, dehydration and compression assets in the Piceance Basin in western Colorado from Encana Oil & Gas (USA) Inc., a subsidiary of Encana for $590.2 million. We refer to these assets as the Grand River system. As of December 31, 2012, the Grand River system comprised approximately 289 miles of pipeline and 97,500 horsepower of compression. It is primarily located in Garfield County, the largest natural gas producing county in Colorado and is composed of three distinct gathering systems that service producers operating in: (i) the Mamm Creek Field, (ii) the South Parachute Field, and (iii) the Orchard Field. Natural gas gathered on these three systems is compressed, dehydrated, and discharged to a pipeline owned by Enterprise Products Partners L.P. ("Enterprise"), which connects to Enterprise's 1.7 Bcf/d processing facility located in Meeker, Colorado. For the year ended December 31, 2012, the Grand River system gathered an average of approximately 575 MMcf/d from six producers, including Encana as the anchor customer.

The Grand River system primarily gathers natural gas produced by our customers from the liquids-rich Mesaverde formation within the Piceance Basin. The Mesaverde is a shallow, tight sands geologic formation that producers have targeted with directional drilling for several decades. We also gather natural gas from our customers' wells targeting the deeper Mancos and Niobrara shale formations. Over the last two years, our customers have completed numerous horizontal wells targeting the emerging Mancos and Niobrara shale formations. These formations generally have higher initial production rates and lower Btu content than Mesaverde wells. Based on our customers' current drilling activities, we anticipate that the majority of our near-term throughput on the Grand River system will continue to originate from the Mesaverde formation.

We intend to expand the Grand River system by connecting additional pad sites within our areas of mutual interest, adding new customers, and acquiring nearby gathering systems. To the extent natural gas prices increase from current levels, we expect that our customers will accelerate drilling activities targeting the Mancos and Niobrara shale formations. Furthermore, increased production from the Mancos and Niobrara shale formations will provide an opportunity for us to construct a new medium-pressure gathering system which will separate liquids-rich natural gas from dry natural gas production, increase total throughput capacity and allow for additional liquids-rich natural gas to

be shipped on the Grand River system.
DFW Midstream System
In September 2009, we acquired approximately 17 miles of pipeline and 2,500 horsepower of electric-drive compression in north-central Texas from Energy Future Holdings Corp. ("Energy Future Holdings") and

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Chesapeake. We refer to these assets as the DFW Midstream system. Since the initial acquisition, we have expanded the DFW Midstream system by adding pipeline and installing incremental compression horsepower. As of December 31, 2012, the DFW Midstream system had approximately 110 miles of pipeline that connected 64 pad sites and had 50,100 horsepower of compression. The DFW Midstream system currently has five primary interconnections with third-party, intrastate pipelines. These interconnections enable us to connect our customers, directly or indirectly, with the major natural gas market hubs of Waha, Carthage, and Katy in Texas, and Perryville and Henry Hub in Louisiana. For the year ended December 31, 2012, the DFW Midstream system gathered an average of approximately 355 MMcf/d from eight producers, including Chesapeake as the anchor customer.

The DFW Midstream system benefits from its location in southeastern Tarrant County, Texas, which is commonly referred to as the core of the Barnett Shale. Based on peak month average daily production rates sourced from the Railroad Commission of Texas as of June 2012, this area contains the most prolific wells in the Barnett Shale. For example, the two largest and four of the 10 largest wells drilled in the Barnett Shale (based on initial production) are connected to the DFW Midstream system.

Development of the DFW Midstream system has enabled our customers to efficiently produce natural gas by utilizing horizontal drilling techniques from pad sites already connected or identified to be connected in our areas of mutual interest. Given the urban nature of southeastern Tarrant County, we expect that the majority of future natural gas drilling in this area will occur from existing pad sites. As a result, we believe we will be able to increase throughput and cash flows with minimal additional capital expenditures.

Organization and Results of Operations

SMLP was formed in May 2012 in anticipation of our initial public offering which closed on October 3, 2012. On October 3, 2012, immediately prior to the closing of the IPO, Summit Investments conveyed an interest in Summit Holdings to our general partner as a capital contribution; our general partner conveyed its interest in Summit Holdings to SMLP; and Summit Investments conveyed its remaining interest in Summit Holdings to SMLP. We issued 14,375,000 common units to the public in the IPO, which included the exercise of the underwriters’ right to purchase additional common units and represented a 28.9% limited partner interest in SMLP. At the time of the IPO, Summit Investments' partnership interest in SMLP was represented by: (i) 10,029,850 common units, or a 20.1% limited partner interest, (ii) 24,409,850 subordinated units, or a 49.0% limited partner interest, and (iii) a 2% general partner interest.

Summit Investments, which owns and controls our general partner, was formed in 2009 by members of our management team and Energy Capital Partners. In August 2011, Energy Capital Partners sold a noncontrolling interest in Summit Investments to GE Energy Financial Services. Due to its ownership interest in Summit Investments and its representation on Summit Investments' board of managers, Energy Capital Partners controls our general partner and its activities, and as a result, SMLP.

We manage our business and analyze our results of operations as a single segment. Our financial results are primarily driven by the volumes of natural gas that we gather across our systems and our management of operations and maintenance expense. We use a variety of financial and operational metrics to analyze our performance.

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The following table presents certain operating and financial measures for the periods indicated:

	Year ended December 31,		
	2012	2011	2010
	(Dollars in thousands)		
Statement of Operations Data:			
Total revenue	$165,499	$103,552	$31,676
Total costs and expenses	110,334	61,864	23,412
Net income	41,726	37,951	8,172
Other Financial and Operating Data:			
EBITDA	$90,656	$53,363	$12,353
Adjusted EBITDA	103,300	56,803	12,353
Capital expenditures	76,698	78,248	153,719
Acquisition expenditures	—	589,462	—
Distributable cash flow	88,492	50,980	11,726
Aggregate average throughput (MMcf/d)	929	431	136

For additional information on the above data as well as the reconciliations of EBITDA, adjusted EBITDA and distributable cash flow to net income and net cash flows provided by operating activities, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A").

Industry Overview

General

The midstream segment of the natural gas industry is the link between the exploration and production of natural gas from the wellhead and the delivery of the natural gas and its other components to end-use markets. Companies within this industry create value at various stages along the natural gas value chain by gathering natural gas from producers at the wellhead, separating the hydrocarbons into dry gas (primarily methane) and NGLs and then routing the separated dry gas and NGLs streams for delivery to end-markets or to the next intermediate stage of the value chain. The following diagram illustrates the assets commonly found along the natural gas value chain:

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Midstream Services

The range of services utilized by midstream natural gas service providers are generally divided into the following six categories:

Gathering. At the initial stages of the midstream value chain, a network of typically small diameter pipelines known as gathering systems directly connect to wellheads, pad sites or other receipt points in the production area. These gathering systems transport natural gas from the wellhead to downstream pipelines or a central location for treating and processing. A large gathering system may involve thousands of miles of gathering lines connected to thousands of wells. Gathering systems are typically designed to be highly flexible to allow gathering of natural gas at different pressures and scalable to allow for additional production and well connections without significant incremental capital expenditures.

Compression. Gathering systems are operated at design pressures that enable the maximum amount of production to be gathered from connected wells. Through a mechanical process known as compression, volumes of natural gas at a given pressure are compressed to a sufficiently higher pressure, thereby allowing those volumes to be delivered to the market via a higher pressure downstream pipeline. Since wells produce at progressively lower field pressures as they age, it becomes necessary to add additional compression over time to maintain throughput across the gathering system.

Treating and Dehydration. Another process in the midstream value chain is treating and dehydration. Treating and dehydration involves the removal of impurities such as water, carbon dioxide, nitrogen and hydrogen sulfide, which may be present when natural gas is produced at the wellhead. These impurities must be removed for the natural gas to meet the specifications for transportation on long-haul intrastate and interstate pipelines. Moreover, end users will not purchase natural gas with high levels of impurities.

Processing. The principal components of natural gas are methane and ethane. Most natural gas also contains varying amounts of other NGLs, which are heavier hydrocarbons that are found in some natural gas streams. Even after treating and dehydration, some natural gas is not suitable for long-haul intrastate and interstate pipeline transportation or commercial use because it contains NGLs and condensate. This natural gas, referred to as liquids-rich natural gas, must also be processed to remove these heavier hydrocarbon components. NGLs not only interfere with pipeline transportation, but are also valuable commodities once removed from the natural gas stream. The removal and separation of NGLs usually takes place in a processing plant using industrial processes that exploit differences in the weights, boiling points, vapor pressures and other physical characteristics of NGL components.

Fractionation. Fractionation is the process by which NGLs are separated into individual liquid products for sale to petrochemical and industrial end users. The NGL components that can be separated in fractionation generally include: ethane, propane, normal butane, iso-butane and natural gasoline. This mixture of raw NGLs is often referred to as y-grade or raw natural gas liquid mix.

Transportation and Storage. After treating and dehydration, processing and fractionation, the natural gas and NGL components are stored, transported and marketed to end-use markets. Each pipeline system typically has storage capacity located both throughout the pipeline network and at major market centers to help temper seasonal demand and daily supply-demand shifts.

Contractual Arrangements

Midstream natural gas services, other than transportation and storage, are usually provided under contractual arrangements that vary in the amount of commodity price risk they carry. Three typical types of contracts are described below.

Fee-Based. Under fee-based arrangements, the service provider typically receives a fee for each unit of natural gas gathered and compressed at the wellhead and an additional fee per unit of natural gas treated or processed at its facility. As a result, the service provider bears no direct commodity price risk exposure.

Percent-of-Proceeds. Under these arrangements, the service provider typically remits to the producers either a percentage of the proceeds from the sale of residue gas and/or NGLs or a percentage of the actual residue gas and/or NGLs at the tailgate. These types of arrangements expose the gatherer/processor to commodity price risk, as the revenues from the contracts directly correlate with the fluctuating price of natural gas and NGLs.

Keep-Whole. Under these arrangements, the service provider keeps 100% of the NGLs produced, and the processed natural gas, or value of the natural gas, is returned to the producer. Since some of the natural gas is used and removed during processing, the processor compensates the producer for the amount of natural gas used

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and removed in processing by supplying additional natural gas or by paying an agreed-upon value for the natural gas utilized. These arrangements have the highest commodity price exposure for the processor because the costs are dependent on the price of natural gas and the revenues are based on the price of NGLs.

Two typical forms of contracts utilized in the transportation and storage of natural gas are described below.

Firm. Firm service requires the reservation of pipeline capacity by a customer between certain receipt and delivery points. Firm customers generally pay a demand or capacity reservation fee based on the amount of capacity being reserved, regardless of whether the capacity is used, plus a usage fee based on the amount of natural gas transported. Firm storage contracts involve the reservation of a specific amount of storage capacity, including injection and withdrawal rights, and generally include a capacity reservation charge based on the amount of capacity being reserved plus an injection and/or withdrawal fee.

Interruptible. Interruptible service is typically short-term in nature and is generally used by customers that either do not need firm service or have been unable to contract for firm service. These customers pay only for the volume of gas actually transported or stored. The obligation to provide this service is limited to available capacity not otherwise used by firm customers, and as such, customers receiving services under interruptible contracts are not assured capacity on the pipeline or at the storage facility.

Business Strategies

Our principal business strategy is to increase the amount of cash distributions we make to our unitholders over time. Our plan for executing this strategy includes the following key components:

- Pursuing accretive acquisition opportunities from Summit Investments. We intend to pursue opportunities to expand our asset base by acquiring midstream infrastructure assets currently owned and operated by Summit Investments. In addition to its significant ownership interest in us, Summit Investments also owns and controls crude oil, natural gas and water-related midstream assets in service and under development in geographic areas outside of our current operations, including the Bakken Shale Play in North Dakota and the DJ Niobrara Shale Play in Colorado. We believe that Summit Investments' economic interest in us incentivizes it to offer us opportunities to acquire these assets in the future under accretive terms.
- Diversifying our asset base by expanding our midstream service offerings and exploring acquisition and development opportunities in various geographic areas. While our natural gas gathering operations in the Piceance Basin and the Barnett Shale currently represent our core business, we intend to diversify into other midstream services such as natural gas processing and crude oil gathering, through both greenfield development projects and acquisitions. We also intend to diversify our operations into other geographic regions through acquisitions and development of new anchor customer relationships. We and our Sponsors are frequently involved in discussions with third parties regarding the purchase of natural gas and crude oil midstream energy infrastructure assets. Working together with our Sponsors, we intend to continue to evaluate opportunities to acquire or develop other midstream energy infrastructure assets that complement our existing business and allow us to leverage our asset base and our management team's development and industry expertise.
- Capitalizing on organic growth opportunities. We believe that our existing gathering systems provide us with significant organic expansion opportunities. We intend to leverage our management team's expertise in constructing, developing and optimizing midstream infrastructure assets to grow our business through organic development projects that are designed to extend our geographic reach, diversify our customer base, expand our midstream service offerings, increase the number of our natural gas receipt points and maximize volume throughput.
- Increasing throughput volumes on our existing systems. We intend to continue to focus on maximizing the utilization of our assets by increasing volume throughput from existing customers and connecting new customers to our systems. For example, we increased the capacity of the DFW Midstream system from 410 MMcf/d to over 450 MMcf/d with the installation of a new compressor unit that came on line in January 2013. In addition, we designed the DFW Midstream system to benefit from incremental volumes arising from high-density, infill drilling on existing pad sites that are already connected to the our gathering system and as such would not require significant additional capital expenditures.
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Maintaining our focus on fee-based revenue with minimal direct commodity price exposure. As we expand our business, we intend to maintain our focus on providing midstream energy services under fee-

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based arrangements. Our midstream services are almost exclusively provided under long-term, fee-based contracts with original terms ranging from 10 years to 25 years. We believe that our focus on fee-based revenues with minimal direct commodity exposure is essential to maintaining stable cash flows and increasing our quarterly distributions over time.

- Partnering with producers to provide midstream services for their development projects in high-growth, unconventional resource plays. We seek to promote commercial relationships with established and well-capitalized producers, who are willing to serve as an anchor customer and commit to long-term volumes and AMIs. We will continue to pursue partnership opportunities with established producers to develop new infrastructure in unconventional resource basins that we believe will complement our existing midstream assets or enhance our overall business by facilitating our entry into new basins. These opportunities generally consist of a strategic acreage position in an unconventional resource play and represent assets that are well-positioned for accelerated production growth but have minimal existing midstream energy infrastructure to support such growth. For example, we have secured agreements covering AMIs from certain of our customers covering all of their natural gas production from approximately 230,000 acres in the Piceance Basin where Encana serves as our anchor customer and 100,000 acres in the Barnett Shale where Chesapeake serves as our anchor customer. We have been successful with this strategy and will continue to pursue similar opportunities that utilize our management team's experience in constructing, developing and operating large scale midstream infrastructure.

Competitive Strengths

We believe that we will be able to execute the components of our principal business strategy successfully because of the following competitive strengths:

Strategically located assets in core areas of prolific unconventional basins supported by existing partnerships with large producers to provide midstream services for their development projects. Our midstream energy infrastructure assets are strategically positioned within the core areas of two established unconventional resource plays. The formations in the basins served by our assets have relatively low drilling and completion costs. We believe that producers will continue their drilling and completion activities in the core areas of unconventional natural gas shale basins even if natural gas prices do not increase significantly from current levels because the return economics associated with core-area wells remain favorable in lower pricing environments compared with more marginal areas of production. We believe that continued drilling activity in these basins positions us to pursue attractive growth opportunities by further developing and optimizing our systems and developing or acquiring complementary systems within our geographic areas of operation.

- Grand River system. The Grand River system is located in the Piceance Basin in western Colorado and currently serves producers targeting the liquids-rich Mesaverde formation. It is optimally located for expansion to gather production from the emerging Mancos and Niobrara shale formations. In response to our customers' recent drilling activities, we have begun constructing a new medium-pressure gathering system to service anticipated future higher pressure gas production from the Mancos and Niobrara shale formations.

- DFW Midstream system. The DFW Midstream system is primarily located in southeastern Tarrant County, currently the largest natural gas producing county in Texas. We consider this area to be the core of the core of the Barnett Shale because of the quality of the geology and the high production profile of the wells drilled to date. We believe that the areas of mutual interest underpinning our system are substantially undeveloped compared with other areas in the Barnett Shale due to the lack of historical gathering infrastructure. Our areas of mutual interest and our system footprint provide us with a competitive advantage to add additional producers and incremental volumes in this core area of the Barnett Shale at a competitive capital cost.

Fee-based revenues underpinned by long-term contracts with minimum volume commitments. A substantial majority of our revenue for the year ended December 31, 2012 was generated under long-term, fee-based gas gathering agreements. Several of our customers are among the largest producers in each of our areas of operation. In the Piceance Basin, we have a 25-year area of mutual interest agreement covering approximately 187,000 acres and 1.4 Tcf of remaining MVCs with Encana through 2026. Together with our other gas gathering agreements with our other customers operating in the Piceance Basin, we have areas of mutual interest covering approximately 230,000 acres and remaining minimum volume commitments of approximately 2.0 Tcf through 2026. In the Barnett Shale, we have a 20-year area of mutual interest with Chesapeake and Total covering approximately 95,000 acres and 287 Bcf of remaining MVCs through 2020. Together with our other gas gathering agreements with our other

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customers operating in the Barnett Shale, we have areas of mutual interest covering approximately 100,000 acres and remaining minimum volume commitments of approximately 372 Bcf through 2020. We believe that long-term, fee-based gas gathering agreements enhances the stability of our cash flows by limiting our direct commodity price exposure.

Capital structure and financial flexibility. At December 31, 2012, we had $199.2 million of indebtedness and $350.8 million of borrowing capacity available to us under our $550.0 million revolving credit facility. Under the terms of the revolving credit facility, our total leverage ratio (net debt divided by EBITDA) was approximately 1.8:1 at December 31, 2012. We believe our borrowing capacity and our ability to access private and public debt and equity capital will provide us with the necessary financial flexibility to execute our growth and expansion strategy.

Experienced management team with proven record of asset acquisition, construction, development, operation and integration expertise. Our executive management team has an average of 18 years of energy experience and a proven track record of identifying and consummating significant acquisitions in addition to partnering with major producers to construct and develop midstream energy infrastructure. As evidenced by our current business, our management team has demonstrated particular expertise in constructing new, as well as developing and optimizing underutilized, midstream assets, which are key elements of our growth strategy. We employ engineering, construction and operations teams that have significant experience in designing, constructing and operating large midstream energy infrastructure.

Relationships with large and committed financial sponsors. Our Sponsors are experienced energy investors with proven track records of making substantial, long-term investments in high-quality energy assets. We believe the relationship with our Sponsors will be a competitive advantage, as they bring not only significant financial and management experience, but also numerous relationships throughout the energy industry that we believe will benefit us as we seek to grow our business. In addition, we believe that our Sponsors will remain motivated to promote and support the successful execution of our business strategies due to their ownership of a substantial portion of our common units and all of our subordinated units.

In October 2012, Summit Investments, which owns and controls our general partner, acquired a natural gas gathering and processing system that gathers and processes production from the Piceance and Uinta basins in Colorado and Utah for $207.0 million. In February 2013, Summit Investments acquired a midstream energy company that owns, operates and is developing various natural gas gathering and processing assets along with crude oil and water gathering assets in the Bakken and DJ Niobrara shale plays for $513.0 million. Summit Investments' purchase of these midstream assets was funded via a cash contribution from Energy Capital Partners. While these assets have not been contributed to SMLP and Summit Investments is not obligated to sell these assets to SMLP, we believe they may represent a future opportunity for execution of our business strategy.

Our Midstream Assets

Our midstream assets currently consist of two natural gas gathering systems, the Grand River system in western Colorado and the DFW Midstream system in north-central Texas. We earn revenue primarily from long-term, fee-based gas gathering agreements with some of the largest and most active producers in our areas of operation. The fee-based nature of these agreements enhances the stability of our cash flows by limiting our direct commodity price exposure. The significant features of our gas gathering agreements and the gathering systems to which they relate are discussed in more detail below.

Areas of Mutual Interest

Our gas gathering agreements contain areas of mutual interest. The areas of mutual interest generally have original terms that range from 10 years to 25 years and require that any production by our customers within the areas of mutual interest will be shipped on our gathering systems. Our customers do not have leases that currently cover our entire areas of mutual interest in the Piceance Basin and Barnett Shale but, to the extent our customers lease additional acreage in the future within those areas of mutual interest, natural gas produced by our customers from that leased acreage will be gathered by the Grand River and DFW Midstream systems.

Under certain of our gas gathering agreements, we have agreed to construct pipeline laterals to connect our gathering systems to pad sites located within the area of mutual interest. If we choose not to participate in a discretionary opportunity presented by a customer, the customer may, in certain circumstances, construct the additional infrastructure and sell it to us at a price equal to their cost plus an applicable margin, or, in some cases, release the relevant acreage dedication from the area of mutual interest.

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Minimum Volume Commitments

Our gas gathering agreements contain MVCs pursuant to which our customers guarantee to ship a minimum volume of natural gas on our gathering systems, or, in some cases, to pay a minimum monetary amount, over certain periods during the term of the MVC. The original terms of the MVCs range from seven to 15 years. In addition, certain of our customers have an aggregate MVC, which is a total amount of natural gas that the customer has agreed to ship on our gathering systems (or an equivalent monetary amount) over the MVC term. In these cases, once a customer achieves its aggregate MVC, any remaining future MVCs will terminate and the customer will then simply pay the applicable gathering rate multiplied by the actual throughput volumes shipped.

If a customer's actual throughput volumes are less than its MVC for the applicable period, it must make a shortfall payment to us at the end of that contract month or year, as applicable. The amount of the shortfall payment is based on the difference between the actual throughput volume shipped for the applicable period and the MVC for the applicable period, multiplied by the applicable gathering fee. To the extent that a customer's actual throughput volumes are above or below its MVC for the applicable period, however, many of our gas gathering agreements contain provisions that can operate to reduce or delay the cash flows that we expect to receive from our MVCs. These provisions include the following:

- To the extent that a customer's throughput volumes are less than its MVC for the applicable period and the customer makes a shortfall payment, it may be entitled to an offset in one or more subsequent periods to the extent that its throughput volumes in subsequent periods exceed its MVC for those periods. In such a situation, we would not receive gathering fees on throughput in excess of a customer's monthly or annual MVC (depending on the terms of the specific gas gathering agreement) to the extent that the customer had made a shortfall payment with respect to one or more preceding months or years (as applicable).
- To the extent that a customer's throughput volumes exceed its MVC in the applicable period, it may be entitled to apply the excess throughput against its aggregate MVC, thereby reducing the period for which its annual MVC applies. For example, one of our DFW Midstream customers has a contracted MVC term from October 2010 through September 2017. However, this customer has regularly shipped volumes in excess of its MVCs. In the fourth quarter of 2012, this customer satisfied the requirements of its aggregate MVC, thereby reducing the period for which its MVC applies from eight years to less than three years. As a result of this mechanism, the weighted-average remaining period for which our MVCs apply is less than the weighted average of the original stated contract terms of our MVCs.
- To the extent that certain of our customers' throughput volumes exceed its MVC for the applicable period, there is a crediting mechanism that allows the customer to build a bank of credits that it can utilize in the future to reduce shortfall payments owed in subsequent periods, subject to expiration if there is no shortfall in subsequent periods. The period over which this credit bank can be applied to future shortfall payments varies, depending on the particular gas gathering agreement.

Grand River System

In October 2011, we acquired the Grand River system from Encana for $590.2 million. The Grand River system is primarily located in Garfield County, the largest natural gas producing county in Colorado, and comprises approximately 289 miles of three inch to 24 inch diameter pipeline and approximately 97,500 horsepower of compression. The Grand River system gathers natural gas from the Mesaverde formation and the Mancos and Niobrara shale formations located within the Piceance Basin. All of the natural gas gathered on the Grand River system is discharged to third-party pipelines that deliver to Enterprise's 1.7 Bcf/d processing facility located in Meeker, Colorado.

The Grand River system is primarily a low-pressure gathering system that was originally designed to gather natural gas produced from traditional vertical wells targeting the liquids-rich Mesaverde formation. As of December 31, 2012, our largest Grand River customer, Encana, had 1,822 wells on 379 pad sites connected to our gathering system. We also receive natural gas from other customers at nine central receipt points on the Grand River system. We expect to continue to pursue additional volumes on the low-pressure system to more fully utilize the existing throughput capacity.

In connection with our acquisition of the Grand River system, we entered into a contractual relationship with Encana related to the development of midstream infrastructure to support Encana's emerging Mancos and Niobrara shale development. In addition to the underpinning provided by our gas gathering agreements, Encana's drilling program in the Mamm Creek and South Parachute fields is supported by its joint venture with Nucor Corporation, which specifies a minimum number of Mesaverde wells to be drilled.

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As of December 31, 2012, the Grand River system had aggregate throughput capacity of 885 MMcf/d. For the year ended December 31, 2012, it gathered an average of approximately 575 MMcf/d from the Mamm Creek, South Parachute and Orchard fields in the area around Rifle, Colorado.
The following table provides information regarding our Grand River system as of December 31, 2012, except as noted.

Gathering system	Approximate length (Miles)	Approximate number of wells serviced (1)	Compression (Horsepower)	Throughput capacity (MMcf/d) (2)	Average throughput (MMcf/d) (3)	Approximate areas of mutual interest (Acres)	Remaining MVCs (Bcf)
Mamm Creek	186	1,375	60,180	600	434	174,000	1,105
South Parachute	39	146	12,168	75	83	17,000	—
Orchard	64	301	25,152	210	58	39,000	875
Total Grand River system	289	1,822	97,500	885	575	230,000	1,980

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(1) Excludes wells connected to nine central receipt points that represent an aggregate average throughput of 256 MMcf/d for the year ended December 31, 2012.
(2) Represents throughput capacity for compressor stations located within a particular area of mutual interest. In 2012, production in the South Parachute field exceeded the amount of throughput capacity in the South Parachute AMI. As a result, this excess volume was compressed and discharged by compressor stations in the Orchard system.
(3) For the year ended December 31, 2012.
Mamm Creek. The Mamm Creek system is underpinned by long-term, fee-based gas gathering and compression agreements with Bill Barrett, Encana, Ursa Resources and WPX Energy. These agreements include minimum volume commitments with original terms ranging from 10 to 15 years and areas of mutual interest with original terms ranging from 10 years to 25 years. As of December 31, 2012, these gas gathering agreements had remaining minimum volume commitments totaling approximately 1.1 Tcf over the next 14 years, an average of approximately 205 MMcf/d through 2026, and areas of mutual interest covering approximately 174,000 acres. For the year ended December 31, 2012, this system gathered approximately 434 MMcf/d. Additionally, because certain customers produced less natural gas than their minimum volume commitments for the Mamm Creek Field, we billed and subsequently collected approximately $9.7 million of minimum volume commitment shortfall payments during 2012.

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South Parachute. The South Parachute system is underpinned by a 25-year, fee-based gas gathering agreement with Encana and areas of mutual interest with an original term of 25 years. As of December 31, 2012, the area of mutual interest covered approximately 17,000 acres. For the year ended December 31, 2012, this system gathered approximately 83 MMcf/d.

Orchard. The Orchard system is underpinned by a 25-year, fee-based gas gathering agreement with Encana and an area of mutual interest with an original term of 25 years. As of December 31, 2012, this gas gathering agreement had remaining minimum volume commitments totaling approximately 875 Bcf over the next 14 years, an average of approximately 162 MMcf/d through 2026, and areas of mutual interest covering approximately 39,000 acres. For the year ended December 31, 2012, this system gathered approximately 58 MMcf/d. Additionally, because Encana produced less natural gas than its 2012 minimum volume commitment, we billed and subsequently collected approximately $4.8 million of minimum volume commitment shortfall payments for fiscal 2012.

DFW Midstream System

The DFW Midstream system is primarily located within southeastern Tarrant County, Texas, which resides within the Fort Worth Basin and includes the Barnett Shale geologic formation. We consider southeastern Tarrant County to be the core of the core of the Barnett Shale because it contains the most prolific wells, including the two largest and four of the 10 largest wells drilled in the Barnett Shale (based on initial production) according to data sourced from the Railroad Commission of Texas as of June 2012. The DFW Midstream system includes gathering lines ranging from 8 inches to 30 inches in diameter and is located along existing electric transmission corridors and under both private and public property. The system currently has five primary interconnections with third-party, intrastate pipelines that enable us to connect our customers with the major natural gas market hubs of Waha, Carthage and Katy in Texas and Perryville and Henry Hub in Louisiana.

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The following table provides information regarding our DFW Midstream system as of December 31, 2012, except as noted.

Gathering system	Approximate length (Miles)	Approximate number of wells serviced	Compression (Horsepower)	Throughput capacity (MMcf/d)	Average throughput (MMcf/d)(1)	Approximate areas of mutual interest (Acres)	Remaining MVCs (Bcf)
DFW Midstream	110	312	50,100	410	355	100,000	372

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(1) For the year ended December 31, 2012.

The DFW Midstream system is underpinned by eight long-term, fee-based gas gathering agreements with Atlas Energy, Beacon E&P, Carrizo, Chesapeake, EOG, Exxon Mobil, TOTAL and Vantage. As of December 31, 2012, these gas gathering agreements had remaining MVCs totaling approximately 372 Bcf and, through 2020, average approximately 127 MMcf/d. In addition, these gas gathering agreements have areas of mutual interest that cover approximately 100,000 acres through 2030. We retain a small fixed percentage of the natural gas that we receive at the receipt points to offset the costs we incur to operate our electric-drive compressors.

We have owned and operated the DFW Midstream system since September 2009 when we acquired it from Energy Future Holdings and concurrently acquired certain complementary pipeline and other related gathering system assets from Chesapeake. We simultaneously entered into a long-term gas gathering agreement with Chesapeake as our anchor customer that included a 20-year area of mutual interest covering approximately 95,000 acres and a 10-year MVC totaling approximately 450 Bcf.

We continue to develop the DFW Midstream system to extend our gathering reach, diversify our customer base, increase our receipt points and maximize throughput. Since the acquisition, we have expanded this system by adding pipeline, continuing to connect additional pad sites located within our areas of mutual interest, and expanding the throughput capacity by installing additional electric-drive compression. For the year ended December 31, 2012, the DFW Midstream system had average throughput of approximately 355 MMcf/d. As of December 31, 2012, the DFW Midstream system included approximately 110 miles of low- and high-pressure gathering lines and 50,100 horsepower of compression. As of December 31, 2012, approximately 312 wells on 64 pad sites were connected to the DFW Midstream system.

While there has been substantial development of the broader 24-county Barnett Shale over the past decade, southeastern Tarrant County, which is located in the core area of the Barnett Shale, has been largely undeveloped due to the urban landscape and the absence of natural gas gathering infrastructure. The DFW Midstream system has addressed the historical lack of gathering infrastructure and currently provides producers in the area with a safe, efficient and reliable solution to deliver their natural gas to market. Tarrant County, which is currently the largest natural gas producing county in Texas, experienced an increase in natural gas production from 1.6 Bcf/d in October 2009 to 2.3 Bcf/d in October 2012. Over this same period, throughput on the DFW Midstream system increased to approximately 400 MMcf/d, which accounted for approximately 60% of Tarrant County's increased natural gas production.

We believe the production profile of wells drilled within our areas of mutual interest and flowing on the DFW Midstream system will continue to attract drilling activity over the long term as producers become more selective in their drilling locations and focus on the core areas of certain basins to maximize their returns. We also believe that the acreage dedicated to the DFW Midstream system has substantial remaining development as evidenced by our 100,000 acre gathering footprint and our customers' efforts to reduce well spacing below 50 acres, thus maximizing recoverable reserves. We believe our strategic location in the Barnett Shale provides us with a competitive advantage to add incremental throughput with limited additional investment capital due to the anticipated future, high-density, infill drilling from our customers on connected pad sites and nearby pad sites that have yet to be connected. This high-density, infill drilling is magnified in our area given the urban landscape and the efforts of our producer customers to minimize their surface footprint.

Our Sponsors

Our Predecessor was formed in 2009 by members of our management and Energy Capital Partners, which together with its affiliated funds, is a private equity firm with over $7.5 billion in capital commitments that is focused on investing in North America's energy infrastructure. Energy Capital Partners has significant energy and financial expertise to complement its investment in us. As of December 31, 2012, Energy Capital Partners and its affiliated

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funds had 24 investment platforms with investments in the power generation, electric transmission, midstream natural gas and renewable sectors of the energy industry. In August 2011, Energy Capital Partners sold an interest in the Predecessor to GE Energy Financial Services. GE Energy Financial Services invests globally in essential, long-lived and capital-intensive energy assets. As of December 31, 2012, GE Energy Financial Services had invested over $20 billion in energy investments worldwide, of which approximately $2.4 billion has been committed to midstream-related portfolio companies.

In October 2012, Summit Investments, which owns and controls our general partner, acquired a natural gas gathering and processing system that gathers and processes production from the Piceance and Uinta basins in Colorado and Utah for $207.0 million. In February 2013, Summit Investments acquired a midstream energy company that owns, operates and is developing various natural gas gathering and processing assets along with crude oil and water gathering assets in the Bakken and DJ Niobrara shale plays for $513.0 million. Summit Investments' purchase of these midstream assets was funded via a cash contribution from Energy Capital Partners. While these assets have not been contributed to SMLP and Summit Investments is not obligated to sell these assets to SMLP, we believe they may represent a future opportunity for execution of our business strategy.

Competition

The natural gas midstream business is competitive. Our competitors include other midstream companies, producers and intrastate and interstate pipelines. Competition for natural gas volumes is primarily based on reputation, commercial terms, service levels, access to end-use markets, location, available capacity, and fuel efficiencies. We may also face competition for production drilled outside of our areas of mutual interest and on attracting third-party volumes to our gathering systems. Additionally, we could face incremental competition to the extent we make acquisitions from third parties.

Regulation of the Oil and Natural Gas Industries

General. Sales by producers of natural gas, crude oil, condensate, and NGLs are currently made at market prices. However, gathering and transportation services are subject to various types of regulation, which may affect certain aspects of our business and the market for our services. The Federal Energy Regulatory Commission ("FERC") regulates the transportation of natural gas in interstate commerce and the interstate transportation of crude oil, petroleum products and NGLs. FERC regulation includes reviewing and accepting or approving rates and other terms and conditions for such transportation services. FERC is also authorized to prevent and sanction market manipulation in natural gas markets while the Federal Trade Commission is authorized to prevent and sanction market manipulation in petroleum markets. State and municipal regulations may apply to the production and gathering of natural gas, the construction and operation of natural gas and crude oil facilities, and the rates and practices of gathering systems and intrastate pipelines.

Regulation of Oil and Natural Gas Exploration, Production and Sales. Sales of crude oil and NGLs are not currently regulated and are transacted at market prices. In 1989, the U.S. Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all remaining price and non-price controls affecting wellhead sales of natural gas. FERC, which has the authority under the Natural Gas Act to regulate the prices and other terms and conditions of the sale of natural gas for resale in interstate commerce, has issued blanket authorizations for all gas resellers subject to its regulation, except interstate pipelines, to resell natural gas at market prices. Either Congress or FERC (with respect to the resale of gas in interstate commerce), however, could re-impose price controls in the future.

Exploration and production operations are subject to various types of federal, state and local regulation, including, but not limited to, permitting, well location, methods of drilling, well operations, and conservation of resources. While these regulations do not directly apply to our business, they may affect our customers' ability to produce natural gas.

Regulation of the Gathering and Transportation of Natural Gas. We believe that our gas pipeline facilities qualify as gathering facilities that are exempt from the jurisdiction of FERC under the Natural Gas Act and the Natural Gas Policy Act of 1978 (the "NGPA"), although we are subject to FERC's anti-market manipulation regulations and certain FERC reporting requirements. The distinction between federally unregulated gathering facilities and FERC-regulated transmission pipelines has been the subject of extensive litigation and changes in the policies and interpretations of laws and regulations. In addition, the status of any individual gathering system may be determined by FERC on a case-by-case basis, although FERC has made no determinations as to the status of

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our facilities. Consequently, the classification and regulation of gathering systems (including some of our pipelines) could change based on future determinations by FERC or the courts.

Intrastate pipelines, which may include some pipelines that perform gathering functions, may be subject to safety regulation by the U.S. Department of Transportation although typically state regulatory authorities (operating under a federal certification) perform this function. State regulatory authorities also have jurisdiction over the rates and practices of intrastate pipelines and gathering systems, including requirements for ratable takes or non-discriminatory access to pipeline services. The basis for state regulation and the degree of regulatory oversight of gathering systems and intrastate pipelines varies from state to state. In Texas, we are regulated as a gas utility and have filed tariffs with the Railroad Commission of Texas to establish rates and terms of service for our DFW Midstream system assets. We have not been required to file a tariff in Colorado for our Grand River system assets. Both of these states have adopted complaint-based regulation that allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve access issues and rate grievances, among other matters. State authorities generally have not initiated investigations of the rates or practices of gathering systems or intrastate pipelines in the absence of a complaint.

Natural gas production, gathering and transportation, including the construction of new gathering facilities and expansion of existing gathering facilities may also be subject to local regulation, such as approval and permit requirements.

Anti-Market Manipulation Rules. We are subject to the anti-market manipulation provisions in the Natural Gas Act and the NGPA, as amended by the Energy Policy Act of 2005, which authorize FERC to impose fines of up to $1,000,000 per day per violation of the Natural Gas Act, the NGPA, or their implementing regulations. In addition, the Federal Trade Commission holds statutory authority under the Energy Independence and Security Act of 2007 to prevent market manipulation in petroleum markets, including the authority to request that a court impose fines of up to $1,000,000 per violation. These agencies have promulgated broad rules and regulations prohibiting fraud and manipulation in oil and gas markets. The Commodity Futures Trading Commission is directed under the Commodity Exchange Act to prevent price manipulations in the commodity and futures markets, including the energy futures markets. Pursuant to statutory authority, the Commodity Futures Trading Commission has adopted anti-market manipulation regulations that prohibit fraud and price manipulation in the commodity and futures markets. The Commodity Futures Trading Commission also has statutory authority to seek civil penalties of up to the greater of $1,000,000 per day per violation or triple the monetary gain to the violator for violations of the anti-market manipulation sections of the Commodity Exchange Act. We are also subject to various reporting requirements that are designed to facilitate transparency and prevent market manipulation.

Safety and Maintenance. We are subject to regulation by the U.S. Department of Transportation under the Natural Gas Pipeline Safety Act of 1968, as amended (the “NGPSA”) which establishes federal safety standards for the design, construction, operation and maintenance of natural gas pipeline facilities. In the Pipeline Safety Act of 1992, Congress expanded the U.S. Department of Transportation's regulatory authority to include regulated gathering lines that had previously been exempt from federal jurisdiction. The Pipeline Safety Improvement Act of 2002 and the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 established mandatory inspections for certain U.S. oil and natural gas transmission pipelines in high consequence areas. The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 reauthorizes funding for federal pipeline safety programs through 2015, increases penalties for safety violations, establishes additional safety requirements for newly constructed pipelines, and requires studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines.

The U.S. Department of Transportation has delegated the implementation of safety requirements to the Pipeline and Hazardous Materials Safety Administration (the "PHMSA"), which has adopted and enforces safety standards and procedures applicable to a limited number of our pipelines. In addition, many states, including the states in which we operate, have adopted regulations, similar to existing U.S. Department of Transportation regulations for intrastate pipelines. Among the regulations applicable to us, the PHMSA requires pipeline operators to develop integrity management programs for certain pipelines located in high consequence areas, which include high-population areas such as the Dallas-Fort Worth greater metropolitan area where our DFW gathering system is located. While the majority of our pipelines meet the U.S. Department of Transportation definition of gathering lines and are thus exempt from the integrity management requirements of the PHMSA, we also operate a limited number of pipelines that are subject to the integrity management requirements. Those regulations require operators, including us, to:

- perform ongoing assessments of pipeline integrity;

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- identify and characterize applicable threats to pipeline segments that could impact a high consequence area;
- maintain processes for data collection, integration and analysis;
- repair and remediate pipelines as necessary;
- adopt and maintain procedures, standards and training programs for control room operations; and
- implement preventive and mitigating actions.

The PHMSA published an advanced notice of proposed rulemaking to solicit comments on the need for changes to its safety regulations, including whether to revise the integrity management requirements and extend the integrity management requirements to certain gathering lines. The PHMSA also recently published an advisory bulletin providing guidance on verification of records related to pipeline maximum allowable operating pressure. Pipelines that do not meet the PHMSA's record verification standards may be required to perform additional testing or reduce their operating pressures.

Gathering systems like ours are also subject to a number of federal and state laws and regulations, including the Federal Occupational Safety and Health Act and comparable state statutes, the purposes of which are to protect the health and safety of workers, both generally and within the pipeline industry. In addition, the OSHA hazard communication standard, Environmental Protection Agency ("EPA") community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that such information be provided to employees, state and local government authorities and the public.

Environmental Matters

General. Our operation of pipelines and other assets for the gathering, compressing and dehydration of natural gas and other products is subject to stringent and complex federal, state and local laws and regulations relating to the protection of the environment. As an owner or operator of these assets, we must comply with these laws and regulations at the federal, state and local levels. These laws and regulations can restrict or impact our business activities in many ways, such as:

- requiring the installation of pollution-control equipment or otherwise restricting the way we operate or imposing additional costs on our operations;
- limiting or prohibiting construction activities in sensitive areas, such as wetlands, coastal regions or areas inhabited by endangered or threatened species;
- delaying system modification or upgrades during permit reviews;
- requiring investigatory and remedial actions to mitigate pollution conditions caused by our operations or attributable to former operations; and
- enjoining the operations of facilities deemed to be in non-compliance with permits or permit requirements issued pursuant to or imposed by such environmental laws and regulations.

Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties. Certain environmental statutes impose strict joint and several liability for costs required to clean up and restore sites where 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 the release of hazardous substances, hydrocarbons or other waste products into the environment.

The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment. Thus, there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation and actual future expenditures may be different from the amounts we currently anticipate. We try to anticipate future regulatory requirements that might be imposed and plan accordingly to remain in compliance with changing environmental laws and regulations and to minimize the costs of such compliance. We also actively participate in industry groups that help formulate recommendations for addressing existing or future regulations.

The following is a discussion of the material environmental laws and regulations that relate to our business.

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Hazardous Substances and Waste. Our operations are subject to environmental laws and regulations relating to the management and release of hazardous substances, solid and hazardous wastes and petroleum hydrocarbons. These laws generally regulate the generation, storage, treatment, transportation and disposal of solid and hazardous waste and may impose strict joint and several liability for the investigation and remediation of affected areas where hazardous substances may have been released or disposed. Furthermore, the Toxic Substances Control Act, and analogous state laws, impose requirements on the use, storage and disposal of various chemicals and chemical substances at our facilities. The Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA") and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that contributed to the release of a hazardous substance into the environment. We may handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment.

We also generate industrial wastes that are subject to the requirements of the Resource Conservation and Recovery Act and comparable state statutes. While the Resource Conservation and Recovery Act regulates both solid and hazardous wastes, it imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. We generate minimal hazardous waste; however, it is possible that non-hazardous wastes, which could include wastes currently generated during our operations, will in the future be designated as hazardous wastes and, therefore, be subject to more rigorous and costly disposal requirements. Moreover, from time to time, the EPA and state regulatory agencies have considered the adoption of stricter disposal standards for non-hazardous wastes, including natural gas wastes.

We currently own or lease properties where hydrocarbons are being or have been handled for many years. Although previous operators have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us or on or under the other locations where these hydrocarbons and wastes have been transported for treatment or disposal. These properties and the wastes disposed thereon may be subject to CERCLA, the Resource Conservation and Recovery Act and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) or to perform remedial operations to prevent future contamination. We are not currently aware of any facts, events or conditions relating to such requirements that could materially impact our operations or financial condition.

Oil Pollution Act. In 1991, the EPA adopted regulations under the Oil Pollution Act. These oil pollution prevention regulations, as amended several times since their original adoption, require the preparation of a Spill Prevention Control and Countermeasure (“SPCC”) plan for facilities engaged in drilling, producing, gathering, storing, processing, refining, transferring, distributing, using, or consuming oil and oil products, and which due to their location, could reasonably be expected to discharge oil in harmful quantities into or upon the navigable waters of the United States. The owner or operator of an SPCC-regulated facility is required to prepare a written, site-specific spill prevention plan, which details how a facility's operations comply with the requirements. To be in compliance, the facility's SPCC plan must satisfy all of the applicable requirements for drainage, bulk storage tanks, tank car and truck loading and unloading, transfer operations (intrafacility piping), inspections and records, security, and training. Most importantly, the facility must fully implement the SPCC plan and train personnel in its execution. We maintain and implement such plans for a number of our facilities.

Air Emissions. Our operations are subject to the federal Clean Air Act and comparable state and local laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our compressor stations, and also impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations and utilize specific emission control technologies to limit emissions. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations and, potentially, criminal enforcement actions. Furthermore, we may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions.

Increased obligations of operators to reduce air emissions of nitrogen oxides and other pollutants from internal combustion engines in transmission service have been enacted by governmental authorities. For example, in August 2010, the EPA published new regulations under the Clean Air Act to control emissions of hazardous air pollutants from existing stationary reciprocating internal combustion engines. In May 2012, the EPA proposed

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amendments to the final rule in response to several petitions for reconsideration. In January 2013, the EPA finalized the proposed amendments. The final amendments, which become effective on April 1, 2013, were published in the Federal Register on January 30, 2013. The rule will require us to undertake certain expenditures and activities, likely including purchasing and installing emissions control equipment, such as oxidation catalysts or non-selective catalytic reduction equipment, on all of our engines following prescribed maintenance practices for engines (which are consistent with our existing practices), and implementing additional emissions testing and monitoring. Compliance with the final rule currently is required by October 2013. We are continuing our evaluation of the cost impacts of the final rule and proposed amendments.

In June 2011, the EPA issued a final rule modifying existing regulations under the Clean Air Act that established new source performance standards for manufacturers, owners and operators of new, modified and reconstructed stationary internal combustion engines. The final rule became effective in August 2011 and may require us to undertake significant expenditures, including expenditures for purchasing, installing, monitoring and maintaining emissions control equipment. In January 2013, the EPA proposed minor amendments to the final rule. We are currently evaluating the impact that this final rule and proposed amendments will have on our operations.

In April 2012, the EPA finalized rules that establish new air emission control requirements for oil and natural gas production and natural gas processing operations. Specifically, the EPA's rule package includes New Source Performance Standards ("NSPS") to address emissions of sulfur dioxide and volatile organic compounds ("VOCs"), and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The rules establish specific new requirements regarding emissions from compressors and controllers at natural gas processing plants, dehydrators, storage tanks and other production equipment. In addition, the rules establish new leak detection requirements for natural gas processing plants at 500 ppm. These rules will require a number of modifications to our operations, including the installation of new equipment to control emissions from our compressors at initial startup, or 60 days after the final rule is published in the Federal Register. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs. In addition, the EPA rules include NSPS for completions of hydraulically fractured natural gas wells, which may impact our customers. Before January 2015, these standards require owners/operators to reduce VOC emissions from natural gas not sent to the gathering line during well completion either by flaring using a completion combustion device or by capturing the gas using green completions with a completion combustion device, thereby capturing gas that would otherwise be flared. Beginning January 2015, operators must capture the gas and make it available for use or sale, which can be done through the use of green completions. The standards are applicable to newly fractured wells as well as existing wells that are refractured. These requirements may result in increased operating costs for producers who drill near our pipelines, which could reduce the volumes of natural gas available to move through our gathering systems.

Water Discharges. The Federal Water Pollution Control Act, also known as the Clean Water Act, and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into state waters as well as waters of the United States and impose requirements affecting our ability to conduct construction activities in waters and wetlands. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System program prohibit the discharge of pollutants and chemicals. Spill prevention, control and countermeasure requirements of federal laws require appropriate containment berms and similar structures to help prevent the contamination of regulated waters in the event of a hydrocarbon tank spill, rupture or leak. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. We have discharge permits in place for a number of our facilities. These permits may require us to monitor and sample the storm water runoff from such facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

Hydraulic Fracturing. The underground injection of oil and natural gas wastes are regulated by the Underground Injection Control program authorized by the Safe Drinking Water Act. The primary objective of injection well operating requirements is to ensure the mechanical integrity of the injection apparatus and to prevent migration of fluids from the injection zone into underground sources of drinking water. We do not conduct any hydraulic fracturing activities. However, a portion of our customers' natural gas production is developed from unconventional sources that require hydraulic fracturing as part of the completion process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into the formation to stimulate gas production. Legislation to amend the Safe Drinking Water Act to repeal the exemption for hydraulic fracturing from the definition of underground injection and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals

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to require disclosure of the chemical constituents of the fluids used in the fracturing process, were proposed in recent sessions of the U.S. Congress. Congress will likely continue to consider legislation to amend the Safe Drinking Water Act to subject hydraulic fracturing operations to regulation under the Act's Underground Injection Control Program to require disclosure of chemicals used in the hydraulic fracturing process. Scrutiny of hydraulic fracturing activities continues in other ways. The federal government is currently undertaking several studies of hydraulic fracturing's potential impacts. The EPA release a progress report on its study in December 2012 and stated that a draft report of the findings of the study is expected in late 2014. In addition, in October 2011, the EPA announced its intention to propose regulations by 2014 under the Clean Water Act to regulate wastewater discharges from hydraulic fracturing and other natural gas production activities. In May 2012, the Bureau of Land Management issued a proposed rule to regulate hydraulic fracturing on public and Indian land. The rule would require companies to publicly disclose the chemicals used in hydraulic fracturing operations to the Bureau of Land Management after fracturing operations have been completed and includes provisions addressing well-bore integrity and flowback water management plans. The Department of the Interior announced on January 18, 2013 that the Bureau of Land Management will issue a revised draft rule by March 31, 2013. Increased regulation of hydraulic fracturing could have an adverse effect on our upstream customers, thereby reducing the volumes of natural gas that we handle and having a potentially indirect adverse effect on our cash flows and results of our operations.

Several states, including including Texas and Colorado, have also proposed or adopted legislative or regulatory restrictions on hydraulic fracturing through additional permit requirements, public disclosure of fracturing fluid contents, operational restrictions, and temporary or permanent bans on hydraulic fracturing in certain environmentally sensitive areas such as watersheds.

In April 2012, the EPA approved final rules that would subject all oil and natural gas operations (production, processing, transmission, storage and distribution) to regulation under the NSPS and National Emission Standards for Hazardous Air Pollutants programs. These rules also include NSPS for completions of hydraulically fractured gas wells. These standards include the reduced emission completion techniques developed in the EPA's Natural Gas STAR program along with pit flaring of gas not sent to the gathering line. The standards would be applicable to newly drilled and fractured wells as well as existing wells that are refractured. Further, the proposed regulations under the National Emission Standards for Hazardous Air Pollutants program include maximum achievable control technology standards for those glycol dehydrators and storage vessels at major sources of hazardous air pollutants not currently subject to maximum achievable control technology standards. At this point, the effect these proposed rules could have on our business has not been determined. While these rules have been finalized, many of the rules' provisions will be phased-in over time, with the more stringent requirements like reduced emission completion not becoming effective until 2015.

Endangered Species Act. The Endangered Species Act restricts activities that may affect endangered or threatened species or their habitats. Some of our pipelines may be located in areas that are designated as habitats for endangered or threatened species.

National Environmental Policy Act. The National Environmental Policy Act (the "NEPA"), establishes a national environmental policy and goals for the protection, maintenance and enhancement of the environment and provides a process for implementing these goals within federal agencies. A major federal agency action having the potential to significantly impact the environment requires review under NEPA and, as a result, many activities requiring FERC approval must undergo NEPA review. Many of our activities are covered under categorical exclusions which results in a shorter NEPA review process. The Council on Environmental Quality has announced an intention to reinvigorate NEPA reviews and in March 2012, issued final guidance that may result in longer review processes.

Climate Change. Recent scientific studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases and including carbon dioxide and methane, may be contributing to warming of Earth's atmosphere. In response to the scientific studies, international negotiations to address climate change have occurred. The United Nations Framework Convention on Climate Change, also known as the Kyoto Protocol, became effective in February 2005 as a result of these negotiations, but the United States did not ratify the Kyoto Protocol. At the end of 2009, an international conference to develop a successor to the Kyoto Protocol issued a document known as the Copenhagen Accord. Pursuant to the Copenhagen Accord, the United States submitted a greenhouse gas emission reduction target of 17 percent by 2020, compared with 2005 levels. We continue to monitor the international efforts to address climate change. Their effect on our operations cannot be determined with any certainty at this time.

In the United States, legislative and regulatory initiatives are underway to limit greenhouse gas emissions. The U.S. Congress has considered legislation that would control greenhouse gas emissions through a cap and trade program and several states have already implemented programs to reduce greenhouse gas emissions. The U.S. Supreme Court determined that greenhouse gas emissions fall within the Clean Air Act definition of an air pollutant, and in response the EPA promulgated an endangerment finding paving the way for regulation of greenhouse gas emissions under the Clean Air Act. In 2010, the EPA issued a final rule, known as the Tailoring Rule, that makes certain large stationary sources and modification projects subject to permitting requirements for greenhouse gas emissions under the Clean Air Act.

In addition, in September 2009, the EPA issued a final rule requiring the reporting of greenhouse gases from specified large greenhouse gas emission sources in the United States beginning in 2011 for emissions in 2010. In November 2010, the EPA published a final rule expanding its existing greenhouse gas emissions reporting to include onshore and offshore oil and natural gas systems beginning in 2012. We are required to report under these rules for certain of our assets. The EPA continues to consider additional climate change requirements, such as the March 2011 proposed rules regarding future coal-fired power plants. Because regulation of greenhouse gas emissions is relatively new, further regulatory, legislative and judicial developments are likely to occur. Such developments may affect how these greenhouse gas initiatives will impact us.

Legislation or regulations that may be adopted to address climate change could also affect the markets for our products by making our products more or less desirable than competing sources of energy. To the extent that our products are competing with higher greenhouse gas emitting energy sources, our products would become more desirable in the market with more stringent limitations on greenhouse gas emissions. Conversely, to the extent that our products are competing with lower greenhouse gas emitting energy sources such as solar and wind, our products would become less desirable in the market with more stringent limitations on greenhouse gas emissions.

Employees

SMLP does not have any employees. All of the employees required to conduct and support its operations are employed by Summit Investments or its affiliates. The officers of our general partner manage our operations and activities. As of December 31, 2012, Summit Investments employed 136 people who provide direct, full-time support to our operations. None of our employees is a member of any labor union, and we have never experienced any business interruption as a result of any labor disputes.

Availability of Reports

SMLP makes certain filings with the Securities and Exchange Commission (the "SEC"), including its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments and exhibits to those reports, available free of charge through its website, www.summitmidstream.com, as soon as reasonably practicable after the date they are filed with, or furnished to, the SEC. The filings are also available at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549 or by calling 1-800-SEC-0330. These filings are also available on the internet at www.sec.gov. SMLP's press releases and recent investor presentations are also available on SMLP's website.

Item 1A. Risk Factors.

Limited partner units are inherently different from capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in similar businesses. The following risk factors should be considered together with all of the other information included in this report.

If any of the following risks were to materialize, our business, financial condition or results of operations could be materially adversely affected. In that case, we might not be able to pay the minimum quarterly distribution on our common units, the trading price of our common units could decline and an investor could lose all or part of its investment in us.

Risks Related to our Business

We may not have sufficient cash from operations following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements to our general partner, to enable us to pay the minimum quarterly distribution or any distribution to holders of our common and subordinated units.

To pay the minimum quarterly distribution of $0.40 per unit per quarter, or $1.60 per unit on an annualized basis, we will require available cash of approximately $20.0 million per quarter, or $79.9 million per year. We may not have

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sufficient available cash from operating surplus each quarter to pay the minimum quarterly distribution. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the volume of natural gas we gather and compress;
- the level of production of natural gas from wells connected to our gathering systems, which is dependent in part on the demand for, and the market prices of, natural gas and NGLs;
- damage to pipelines, facilities, related equipment and surrounding properties caused by earthquakes, floods, fires, severe weather, explosions and other natural disasters, accidents and acts of terrorism;
- leaks or accidental releases of hazardous materials into the environment, whether as a result of human error or otherwise;
- changes in the fees we charge for our services;
- the level of competition from other midstream energy companies in our geographic markets;
- changes in the level of our operating, maintenance and general and administrative costs;
- regulatory action affecting the supply of, or demand for, natural gas, the fees we can charge, how we contract for services, our existing contracts, our operating costs or our operating flexibility; and
- prevailing economic and market conditions.

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

- the level and timing of capital expenditures we make;
- the level of our operating and general and administrative expenses, including reimbursements to our general partner for services provided to us;
- the cost of acquisitions, if any;
- our debt service requirements and other liabilities;
- fluctuations in our working capital needs;
- our ability to borrow funds and access capital markets;
- restrictions contained in our debt agreements;
- the amount of cash reserves established by our general partner; and
- other business risks affecting our cash levels.

We depend on a relatively small number of customers for a significant portion of our revenues. The loss of, or material nonpayment or nonperformance by, or the curtailment of production by, any one or more of these customers could materially adversely affect our revenues, cash flow and ability to make cash distributions to our unitholders.

A significant percentage of our revenue is attributable to a relatively small number of customers. If our customers curtail or reduce production in our areas of operation it could reduce throughput on our system and, therefore, materially adversely affect our revenues, cash flow and ability to make cash distributions to our unitholders.

Some of our customers may have material financial and liquidity issues or may, as a result of operational incidents or other events, be disproportionately affected as compared to larger, better-capitalized companies. Any material nonpayment or nonperformance by any of our key customers could have a material adverse effect on our revenue and cash flows and our ability to make cash distributions to our unitholders. We expect our exposure to concentrated risk of non-payment or non-performance to continue as long as we remain substantially dependent on a relatively small number of customers for a substantial portion of our revenue. In addition, if any one or more of our gas gathering agreements that account for 25% or more of our revenues are terminated, and such termination is reasonably expected to have a Material Adverse Effect (as defined in our amended and restated revolving credit facility), and a replacement agreement is not obtained within 30 days, this would constitute an event of default under our amended and restated revolving credit facility and our lenders would be able to accelerate payment of the debt outstanding thereunder.

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We gather natural gas from the Piceance Basin and the Barnett Shale. Due to our lack of industry and geographic diversification, adverse developments in our existing areas of operation could materially adversely impact our financial condition, results of operations and cash flows and reduce our ability to make cash distributions to our unitholders.

Our operations are focused on natural gas gathering and compression services. Our assets are located exclusively in the Piceance Basin in western Colorado and the Barnett Shale region in north-central Texas and we intend to focus our future capital expenditures largely on developing our business in these areas. As a result, our financial condition, results of operations and cash flows depend upon the demand for our services in these regions. Due to our lack of industrial and geographic diversity, adverse developments in our current segment of the midstream industry or our existing areas of operation could have a significantly greater impact on our financial condition, results of operations and cash flows than if our operations were more diversified. For example, the natural gas we gather in the Barnett Shale is dry gas. Due to recent declines in natural gas prices, several of our customers have announced their intent to reduce capital expenditures for dry gas drilling activities.

Our operations in the Barnett Shale region could expose us to disproportionate operational and regulatory risk in that area. The location of the Barnett Shale in the Dallas-Fort Worth, Texas metropolitan area poses unique challenges associated with drilling for and gathering natural gas in urban and suburban communities. The DFW Midstream system is within the city limits of various municipalities in that region, including Arlington, Texas. State and local regulations regarding the operation of drilling rigs limit the number of potential new drilling sites that can be used for infill drilling programs, which has led producers to pursue a high-density pad site drilling strategy. Furthermore, the process of obtaining permits for constructing additional gathering lines to deliver our customers' natural gas to market may be more time consuming and costly than in more rural areas. In addition, we may experience a higher rate of litigation or increased insurance and other costs related to our operations or facilities in such highly populated areas.

Significant prolonged changes in natural gas prices could affect supply and demand, reducing throughput on our systems and materially adversely affecting our revenues and cash available to make cash distributions to our unitholders over the long-term.

Lower natural gas prices over the long-term could result in a decline in the production of natural gas resulting in reduced throughput on our systems. Recently, the price of natural gas has been at historically low levels. The lower price of natural gas is due in part to increased production, especially from unconventional sources, such as natural gas shale plays, high levels of natural gas in storage and the effects of the economic downturn starting in 2008. Furthermore, the amount of natural gas in storage in the continental United States has increased due to the decisions of many producers to store natural gas in the expectation of higher prices in the future as well as decreased demand as a result of unseasonably warm winters. In response to lower natural gas prices, the number of natural gas drilling rigs has declined as a number of producers have curtailed their exploration and production activities. We believe that over the short term, until the supply overhang has been reduced and the economy sees more robust growth, natural gas pricing is likely to be constrained.

The current level of low natural gas prices has had a negative impact on exploration, development and production activity in our areas of operation. If natural gas prices remain depressed or decrease further, it could cause sustained reductions in exploration or production activity in our areas of operation and result in a further reduction in throughput on our systems, which could have a material adverse effect on our business, financial condition, results of operations and ability to make quarterly cash distributions to our unitholders.

Also, higher natural gas prices over the long-term could result in a decline in the demand for natural gas and, therefore, in the throughput on our systems. As a result, significant prolonged changes in natural gas prices could have a material adverse effect on our business, financial condition, results of operations and ability to make quarterly cash distributions to our unitholders.

Because of the natural decline in production from existing wells in our areas of operation, our success depends in part on our customers replacing declining production and also on our ability to maintain levels of throughput on our systems. Any decrease in the volumes of natural gas that we gather could materially adversely affect our business and operating results.

The natural gas volumes that support our business depend on the level of production from natural gas wells connected to our systems, the production from which may be less than expected and will naturally decline over time. As a result, our cash flows associated with these wells will also decline over time. To maintain or increase throughput levels on our systems, we must obtain new sources of natural gas. The primary factors affecting our

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ability to obtain non-dedicated sources of natural gas include (i) the level of successful drilling activity in our areas of operation and (ii) our ability to compete for volumes from successful new wells.

We have no control over the level of drilling activity in our areas of operation, the amount of reserves associated with wells connected to our systems or the rate at which production from a well declines. In addition, we have no control over producers or their drilling and production decisions, which are affected by, among other things:

- the availability and cost of capital;
- prevailing and projected commodity prices, including the prices of oil, natural gas and NGLs;
- demand for oil, natural gas and NGLs;
- levels of reserves;
- geological considerations;
- environmental or other governmental regulations, including the availability of drilling permits and the regulation of hydraulic fracturing; and
- the availability of drilling rigs and other costs of production and equipment.

Fluctuations in energy prices can also greatly affect the development of new oil and natural gas reserves. Drilling and production activity generally decreases as natural gas prices decrease. In general terms, the prices of natural gas, oil and other hydrocarbon products fluctuate in response to changes in supply and demand, market uncertainty and a variety of additional factors that are beyond our control. These factors include:

- worldwide economic conditions;
- weather conditions and seasonal trends;
- the levels of domestic production and consumer demand;
- the availability of imported liquefied natural gas ("LNG");
- the ability to export LNG;
- the availability of transportation systems with adequate capacity;
- the volatility and uncertainty of regional pricing differentials and premiums;
- the price and availability of alternative fuels;
- the effect of energy conservation measures;
- the nature and extent of governmental regulation and taxation; and
- the anticipated future prices of natural gas, LNG and other commodities.

Because of these factors, even if new natural gas reserves are known to exist in areas served by our assets, producers may choose not to develop those reserves. If reductions in drilling activity result in our inability to maintain the current levels of throughput on our systems, those reductions could reduce our revenue and cash flow and materially adversely affect our ability to make cash distributions to our unitholders.

Recent declines in natural gas prices have had a negative impact on exploration, development and production activity and, if sustained, could lead to further decreases in such activity. Sustained reductions in exploration or production activity in our areas of operation could lead to further reductions in the utilization of our systems, which could have a material adverse effect on our business, financial condition, results of operations and ability to make quarterly cash distributions to our unitholders.

In addition, it may be more difficult to maintain or increase the current volumes on our gathering systems, as several of the formations in the unconventional resource plays in which we operate generally have higher initial production rates and steeper production decline curves than wells in more conventional basins. Should we determine that the economics of our gathering assets do not justify the capital expenditures needed to grow or maintain volumes associated therewith, revenues associated with these assets will decline over time. In addition to capital expenditures to support growth, the steeper production decline curves associated with unconventional resource plays may require us to incur higher maintenance capital expenditures over time, which will reduce our cash available for distribution from operating surplus.

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Many of our operating costs are fixed and do not vary with our throughput. These costs may not decline ratably or at all should we experience a reduction in throughput, which would result in a decline in our revenue and cash flow and materially adversely affect our ability to make cash distributions to our unitholders.

If our customers do not increase the volumes of natural gas they provide to our gathering systems, our growth strategy and ability to increase cash distributions to our unitholders may be materially adversely affected.

If we are unsuccessful in attracting new customers, our ability to increase the throughput on our gathering systems will be dependent on receiving increased volumes from our existing customers. Other than the scheduled increases in the minimum volume commitments provided for in our gas gathering agreements, our customers are not obligated to provide additional volumes to our systems, and they may determine in the future that drilling activities in areas outside of our current areas of operation are strategically more attractive to them. Reductions by our customers in our areas of mutual interest could result in reductions in throughput on our systems and materially adversely impact our ability to grow our operations and increase cash distributions to our unitholders.

Our gas gathering agreements contain provisions that can reduce the cash flow stability that the agreements were designed to achieve.

Our gas gathering agreements were designed to generate stable cash flows for us over the life of the minimum volume commitment contract term while also minimizing direct commodity price risk. Under these minimum volume commitments, our customers agree to ship a minimum volume of natural gas on our gathering systems or, in some cases, to pay a minimum monetary amount, over certain periods during the term of the minimum volume commitment. In addition, the majority of our gas gathering agreements also include an aggregate minimum volume commitment, which is a total amount of natural gas that the customer must transport on our gathering system (or an equivalent monetary amount) over the minimum volume commitment term. If a customer's actual throughput volumes are less than its minimum volume commitment for the applicable period, it must make a shortfall payment to us at the end of that contract month or year, as applicable. The amount of the shortfall payment is based on the difference between the actual throughput volume shipped for the applicable period and the minimum volume commitment for the applicable period, multiplied by the applicable gathering fee. To the extent that a customer's actual throughput volumes are above or below its minimum volume commitment for the applicable period, many of our gas gathering agreements contain provisions that allow the customer to use the excess volumes or the shortfall payment to credit against future excess volumes or future shortfall payments in subsequent periods. These provisions include the following:

- To the extent that a customer's throughput volumes are less than its minimum volume commitment for the applicable period and the customer makes a shortfall payment, it may be entitled to an offset in one or more subsequent periods to the extent that its throughput volumes in subsequent periods exceed its minimum volume commitment for those periods. In such a situation, we would not receive gathering fees on throughput in excess of a customer's monthly or annual minimum volume commitment (depending on the terms of the specific gas gathering agreement) to the extent that the customer had made a shortfall payment with respect to one or more preceding months or years (as applicable). As of December 31, 2012, we recorded an aggregate of $11.8 million of deferred revenue with respect to shortfall payments that could reduce gathering fees received in the next one month to nine years to the extent that a customer's throughput volumes exceed its minimum volume commitment.
- To the extent that a customer's throughput volumes exceed its minimum volume commitment in the applicable period, it may be entitled to apply the excess throughput against its aggregate minimum volume commitment, thereby reducing the period for which its annual minimum volume commitment applies. For example, one of our DFW Midstream customers has a contracted minimum volume commitment term from October 2010 through September 2017. However, this customer regularly shipped volumes in excess of its minimum volume commitments and satisfied the requirements of its aggregate minimum volume commitment in the fourth quarter of 2012, thereby reducing the period for which its minimum volume commitment applies from eight years to less than three years. As a result of this mechanism, the weighted-average remaining period for which our minimum volume commitments apply is less than the weighted-average of the original stated terms of our minimum volume commitments.
- To the extent that certain of our customers' throughput volumes exceed its MVC for the applicable period, there is a crediting mechanism that allows the customer to build a bank of credits that it can utilize in the future to reduce

shortfall payments owed in subsequent periods, subject to expiration in the event that there is no shortfall in subsequent periods. The period over which this credit bank can be applied to future shortfall payments varies, depending on the particular gas gathering agreement. In such a situation, we

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would receive lower gathering fees in a particular contract year than we would otherwise be entitled to receive under the customer's minimum volume commitment.

Under certain circumstances, it is possible that the combined effect of the minimum volume commitment provisions could result in our receiving no revenues or cash flows from one or more customers in a given period. In the most extreme circumstances:

- we could incur operating expenses with no corresponding revenues from one or more significant customers for a period of up to 35 months; or
- all or a substantial portion of our customers could cease shipping throughput volumes at a time when their respective aggregate minimum volume commitments have been satisfied with previous throughput volume shipments.

If either of these circumstances were to occur, it would have a material adverse effect on our results of operations, financial condition and cash flows and our ability to make cash distributions to our unitholders.

We do not intend to obtain independent evaluations of natural gas reserves connected to our gathering and transportation systems on a regular or ongoing basis; therefore, in the future, volumes of natural gas on our systems could be less than we anticipate.

We have not obtained and do not intend to obtain independent evaluations of the natural gas reserves connected to our systems on a regular or ongoing basis. Moreover, even if we did obtain independent evaluations of the natural gas reserves connected to our systems, such evaluations may prove to be incorrect. Oil and natural gas reserve engineering requires subjective estimates of underground accumulations of oil and natural gas and assumptions concerning future oil and natural gas prices, future production levels and operating and development costs.

Accordingly, we may not have accurate estimates of total reserves dedicated to some or all of our systems or the anticipated life of such reserves. If the total reserves or estimated life of the reserves connected to our gathering and transportation systems are less than we anticipate and we are unable to secure additional sources of natural gas, it could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

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

We compete with other midstream companies in our areas of operation. Some of our competitors are large companies that have greater financial, managerial and other resources than we do. In addition, some of our competitors have assets in closer proximity to gas supplies and have available idle capacity in existing assets that would not require new capital investments for use. Our competitors may expand or construct gathering systems that would create additional competition for the services we provide to our customers. Because our customers do not have leases that cover the entirety of our areas of mutual interest, non-customer producers that lease acreage within any of our areas of mutual interest and produce natural gas may choose to use one of our competitors to gather that natural gas.

In addition, our customers may develop their own gathering systems outside of our areas of mutual interest. Our ability to renew or replace existing contracts with our customers at rates sufficient to maintain current revenue and cash flow could be materially adversely affected by the activities of our competitors and our customers. All of these competitive pressures could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

We may not be able to renew or replace expiring contracts at favorable rates or on a long-term basis.

We gather the natural gas on our systems under contracts with terms of various durations. As these contracts expire, we may have to negotiate extensions or renewals with existing suppliers and customers or enter into new contracts with other suppliers and customers. We may be unable to obtain new contracts on favorable commercial terms, if at all. We also may be unable to maintain the economic structure of a particular contract with an existing customer or the overall mix of our contract portfolio. Moreover, we may be unable to obtain areas of mutual interest from new customers in the future, and we may be unable to renew existing areas of mutual interest with current customers as and when they expire. The extension or replacement of existing contracts depends on a number of factors beyond our control, including:

- the level of existing and new competition to provide gathering services to our markets;

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- the macroeconomic factors affecting natural gas gathering economics for our current and potential customers;
- the balance of supply and demand, on a short-term, seasonal and long-term basis, in our markets;
- the extent to which the customers in our markets are willing to contract on a long-term basis; and
- the effects of federal, state or local regulations on the contracting practices of our customers.

To the extent we are unable to renew our existing contracts on terms that are favorable to us or successfully manage our overall contract mix over time, our revenues and cash flows could decline and our ability to make cash distributions to our unitholders could be materially adversely affected.

We are exposed to the creditworthiness and performance of our customers, suppliers and contract counterparties, and any material nonpayment or nonperformance by one or more of these parties could materially adversely affect our financial and operating results.

Although we attempt to assess the creditworthiness of our customers, suppliers and contract counterparties, there can be no assurance that our assessments will be accurate or that there will not be a rapid or unanticipated deterioration in their creditworthiness, which may have an adverse impact on our business, results of operations, financial condition and ability to make cash distributions to our unitholders. In addition, there can be no assurance that our contract counterparties will perform or adhere to existing or future contractual arrangements.

The policies and procedures we use to manage our exposure to credit risk, such as credit analysis, credit monitoring and, in some cases, requiring credit support, cannot fully eliminate counterparty credit risks. To the extent our policies and procedures prove to be inadequate, our financial and operational results may be negatively impacted.

Some of our counterparties may be highly leveraged or have limited financial resources and will be subject to their own operating and regulatory risks. Even if our credit review and analysis mechanisms work properly, we may experience financial losses in our dealings with such parties. In addition, volatility in commodity prices might have an impact on many of our counterparties, which, in turn, could have a negative impact on their ability to meet their obligations to us and may also increase the magnitude of these obligations.

Any material nonpayment or nonperformance by any of our counterparties could require us to pursue substitute counterparties for the affected operations, reduce our operations or seek out alternative service providers. There can be no assurance that any such efforts would be successful or would provide similar financial and operational results.

If third-party pipelines or other midstream facilities interconnected to our gathering systems become partially or fully unavailable, our revenue and cash flow and our ability to make cash distributions to our unitholders could be materially adversely affected.

Our natural gas gathering pipelines connect to other pipelines and midstream facilities, such as processing plants, owned and operated by unaffiliated third parties. The continuing operation of such third-party pipelines and other midstream facilities is not within our control. These pipelines and other midstream facilities may become unavailable because of testing, turnarounds, line repair, reduced operating pressure, lack of operating capacity, regulatory requirements, curtailments of receipt or deliveries due to insufficient capacity or because of damage from other operational hazards. In addition, we do not have interconnect agreements with all of these pipelines and other facilities and the agreements we do have may be terminated in certain circumstances and on short notice. If any of these pipelines or other midstream facilities become unavailable for any reason, or, if these third parties are otherwise unwilling to receive or transport the natural gas that we gather, our revenue, cash flow and ability to make cash distributions to our unitholders could be materially adversely affected.

We have a limited ownership history with respect to all of our assets. There could be unknown events or conditions or increased maintenance or repair expenses and downtime associated with our pipelines that could have a material adverse effect on our business and operating results.

We purchased the substantial majority of our assets in September 2009 and in October 2011. As a result, our executive management team has a limited history of operating our assets. There may be historical occurrences or latent issues regarding our pipeline systems that our executive management team may be unaware of and that may have a material adverse effect on our business and results of operations. The steeper production decline curves associated with unconventional resource plays may require us to incur higher maintenance capital expenditures over time to connect additional wells and maintain throughput volume. Any significant increase in maintenance and

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repair expenditures or loss of revenue due to the condition of our pipeline systems could materially adversely affect our business and results of operations and our ability to make cash distributions to our unitholders.

A shortage of skilled labor in the midstream natural gas industry could reduce employee productivity and increase costs, which could have a material adverse effect on our business and results of operations.

The gathering of natural gas requires skilled laborers in multiple disciplines such as equipment operators, mechanics and engineers, among others. We have from time to time encountered shortages for these types of skilled labor. If we experience shortages of skilled labor in the future, our labor and overall productivity or costs could be materially adversely affected. If our labor prices increase or if we experience materially increased health and benefit costs with respect to our general partner's employees, our business and results of operations and our ability to make cash distributions to our unitholders could be materially adversely affected.

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

Our operations are subject to all of the risks and hazards inherent in the gathering, compressing and dehydrating of natural gas, including:

- damage to pipelines and plants, related equipment and surrounding properties caused by tornadoes, floods, fires and other natural disasters and acts of terrorism;
- inadvertent damage from construction, vehicles, farm and utility equipment;
- leaks of natural gas and other hydrocarbons or losses of natural gas as a result of the malfunction of equipment or facilities;
- ruptures, fires and explosions; 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 and/or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage. The location of certain of our systems in or near populated areas, including residential areas, commercial business centers and industrial sites, could increase the damages resulting from these risks.

These risks may also result in curtailment or suspension of our operations. A natural disaster or any event such as those described above affecting the areas in which we and our customers operate could have a material adverse effect on our operations. Accidents or other operating risks could further result in loss of service available to our customers. Such circumstances, including those arising from maintenance and repair activities, could result in service interruptions on segments of our systems. Potential customer impacts arising from service interruptions on segments of our systems could include limitations on our ability to satisfy customer requirements, obligations to temporarily waive minimum volume commitments to customers during times of constrained capacity, and solicitation of existing customers by others for potential new projects that would compete directly with existing services. Such circumstances could materially adversely impact our ability to meet contractual obligations and retain customers, with a resulting negative impact on our business and results of operations and our ability to make cash distributions to our unitholders.

Although we have a range of insurance programs providing varying levels of protection for public liability, damage to property, loss of income and certain environmental hazards, we may not be insured against all causes of loss, claims or damage that may occur. If a significant accident or event occurs for which we are not fully insured, it could materially adversely affect our operations and financial condition. Furthermore, we may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. As a result of market conditions, premiums and deductibles for certain of our insurance policies may substantially increase. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage. Additionally, with regard to the assets we have acquired, we have limited indemnification rights to recover for potential environmental liabilities.

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We intend to grow our business in part by seeking strategic acquisition opportunities. If we are unable to make acquisitions on economically acceptable terms from Summit Investments or third parties, our future growth will be affected, and the acquisitions we do make may reduce, rather than increase, our cash generated from operations on a per-unit basis.

Our ability to grow depends, in part, on our ability to make acquisitions that increase our cash generated from operations on a per-unit basis. The acquisition component of our strategy is based, in large part, on our expectation of ongoing divestitures of midstream energy assets by industry participants. A material decrease in such divestitures would limit our opportunities for future acquisitions and could materially adversely affect our ability to grow our operations and increase our cash distributions to our unitholders.

If we are unable to make accretive acquisitions from Summit Investments or third parties, whether because we are (i) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts; (ii) unable to obtain financing for these acquisitions on economically acceptable terms; (iii) outbid by competitors; or (iv) we are unable to obtain necessary governmental or third-party consents or for any other reason, then our future growth and ability to increase cash distributions will be limited. Furthermore, even if we do make acquisitions that we believe will be accretive, these acquisitions may nevertheless result in a decrease in the cash generated from operations on a per-unit basis.

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

- mistaken assumptions about volumes, revenue and costs, including synergies and potential growth;
- an inability to secure adequate customer commitments to use the acquired systems or facilities;
- the risk that natural gas or crude oil reserves expected to support the acquired assets may not be of the anticipated magnitude or may not be developed as anticipated;
- an inability to integrate successfully the assets or businesses we acquire;
- coordinating geographically disparate organizations, systems and facilities;
- the assumption of unknown liabilities for which we are not indemnified or for which our indemnity is inadequate;
- mistaken assumptions about the overall costs of equity or debt;
- the diversion of management's and employees' attention from other business concerns;
- unforeseen difficulties operating in new geographic areas and business lines; and
- customer or key employee losses at the acquired businesses.

If we consummate any future acquisitions, our capitalization and results of operations may change significantly, and our unitholders will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

Our construction of new assets may not result in revenue increases and will be subject to regulatory, environmental, political, legal and economic risks, which could materially adversely affect our results of operations and financial condition.

One of the ways we intend to grow our business is through organic growth projects. The construction of additions or modifications to our existing systems and the construction of new midstream assets involve numerous regulatory, environmental, political, legal and economic uncertainties that are beyond our control. Such expansion projects may also require the expenditure of significant amounts of capital, and financing may not be available on economically acceptable terms or at all. If we undertake these projects, they may not be completed on schedule, at the budgeted cost, or at all. Moreover, our revenue may not increase immediately upon the expenditure of funds on a particular project. For instance, as we develop our medium pressure system to serve the Mancos and Niobrara shale formations, the construction will occur over an extended period of time, yet we will not receive any material increases in revenue until the project is completed and placed into service. Moreover, we could construct facilities to capture anticipated future growth in production in a region in which such growth does not materialize or only materializes over a period materially longer than expected. To the extent we rely on estimates of future production in our decision to construct additions to our systems, such estimates may prove to be inaccurate as a result of the numerous uncertainties inherent in estimating quantities of future production. As a result, new facilities may not attract enough throughput to

achieve our expected investment return, which could materially adversely affect our results of operations and financial condition.

In addition, the construction of additions to our existing gathering assets may require us to obtain new rights-of-way or federal and state environmental or other authorizations. The approval process for gathering activities has become increasingly challenging, due in part to state and local concerns related to unregulated exploration and production and gathering activities in new production areas. Such authorization may not be granted or, if granted, such authorization may include burdensome or expensive conditions. As a result, we may be unable to obtain such rights-of-way or other authorizations and may, therefore, be unable to connect new natural gas volumes to our systems or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive for us to obtain new rights-of-way or authorizations or to renew existing rights-of-way or authorizations. If the cost of renewing or obtaining new rights-of-way or authorizations increases materially, our cash flows could be materially adversely affected.

We require access to significant amounts of additional capital to implement our growth strategy, as well as to meet potential future capital requirements under certain of our gas gathering agreements. Tightened capital markets could impair our ability to grow or cause us to be unable to meet future capital requirements.

To expand our asset base, whether through acquisitions or organic growth, we will need to make expansion capital expenditures. We also frequently consider and enter into discussions with third parties regarding potential acquisitions. In addition, the terms of certain of our gas gathering agreements also require us to spend significant amounts of capital, including over a short period of time, to construct and develop additional midstream assets to support our customers' development projects. For example, in connection with our acquisition of the Grand River system, we agreed to invest capital, subject to a maximum of $200.0 million in any annual period, to construct the necessary facilities to support our primary customer’s drilling program in the Mancos and Niobrara shale formations. Depending on our customers' future development plans, it is possible that the capital we would be required to spend to construct and develop such assets could exceed our ability to finance those expenditures using our cash reserves or available capacity under our amended and restated credit facility.

We will be required to use cash from operations, incur borrowings, and/or sell additional common units or other securities to fund our future expansion capital expenditures. Using cash from operations to fund expansion capital expenditures will directly reduce our cash available for distribution to unitholders. Our ability to obtain financing or to access the capital markets for future equity or debt offerings may be limited by our financial condition at the time of any such financing or offering as well as covenants in our debt agreements, general economic conditions and contingencies and uncertainties that are beyond our control. If we are unable to raise expansion capital, we may lose the opportunity to make acquisitions or to gather natural gas production from new upstream projects developed by our customers with whom we have agreed to construct and develop midstream assets in the future. Even if we are successful in obtaining funds for expansion capital expenditures through equity or debt financings, the terms thereof could limit our ability to pay distributions to our common unitholders. In addition, incurring additional debt may significantly increase our interest expense and financial leverage, and issuing additional units representing limited partner interests may result in significant common unitholder dilution and increase the aggregate amount of cash required to maintain the then-current distribution rate, which could materially decrease our ability to pay distributions at the then-current distribution rate.

We do not have any commitment from our Sponsors or their affiliates to provide any direct or indirect financial assistance to us.

Because our common units are yield-oriented securities, increases in interest rates could materially adversely impact our unit price, our ability to issue equity or incur debt for acquisitions or other purposes and our ability to make cash distributions.

Interest rates are generally at or near historic lows and may increase in the future. As a result, interest rates on our future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase. As with other yield-oriented securities, our unit price is impacted by the level of our cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our units, and a rising interest rate environment could have an material adverse impact on our unit price, our ability to issue equity or incur debt for acquisitions or other purposes and our ability to make cash distributions at our intended levels.

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Debt we incur in the future may limit our flexibility to obtain financing and to pursue other business opportunities.
As of December 31, 2012, we had approximately $199.2 million of total indebtedness and approximately $350.8 million available for future borrowings under our $550.0 million revolving credit facility. Our future level of debt could have significant consequences, including the following:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;
- our funds available for operations, future business opportunities and cash distributions to unitholders will be reduced by that portion of our cash flow required to make interest payments on our debt;
- we may be more vulnerable to competitive pressures or a downturn in our business or the economy generally; and
- our flexibility in responding to changing business and economic conditions may be limited.

Our ability to service our debt will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control. If our operating results are not sufficient to service any future indebtedness, we will be forced to take actions such as reducing distributions, reducing or delaying our business activities, acquisitions, investments or capital expenditures, selling assets or seeking additional equity capital. We may not be able to effect any of these actions on satisfactory terms or at all.
Restrictions in our amended and restated revolving credit facility could materially adversely affect our business, financial condition, results of operations, ability to make cash distributions to unitholders and value of our common units.
Our amended and restated revolving credit facility limits our ability to, among other things:

- incur or guarantee additional debt;
- make cash distributions on or redeem or repurchase units;
- make certain investments and acquisitions;
- make capital expenditures;
- incur certain liens or permit them to exist;
- enter into certain types of transactions with affiliates;
- merge or consolidate with another company or otherwise engage in a change of control; and
- transfer, sell or otherwise dispose of assets.

Our amended and restated revolving credit facility also contains covenants requiring us to maintain certain financial ratios. Our ability to meet those financial ratios and tests can be affected by events beyond our control, and we cannot guarantee that we will meet those ratios and tests. In addition, our credit facility contains events of default customary for credit facilities of this size and nature.
The provisions of our amended and restated revolving credit facility may affect our ability to obtain future financing and pursue attractive business opportunities as well as affect our flexibility in planning for, and reacting to, changes in business conditions. In addition, a failure to comply with the provisions of our amended and restated revolving credit facility could result in a default or an event of default that could enable our lenders to declare the outstanding principal of that debt, together with accrued and unpaid interest, to be immediately due and payable. If the payment of our debt is accelerated, our assets may be insufficient to repay such debt in full, and our unitholders could experience a partial or total loss of their investment.
A portion of our revenues are exposed to changes in oil and natural gas prices, and our exposure may increase in the future.
We generate a substantial majority of our revenues pursuant to long-term, fee-based gas gathering agreements under which we are paid based on the volumes of natural gas that we gather rather than the value of the underlying natural gas. Consequently, our existing operations and cash flows have limited direct exposure to commodity price risk. Although we intend to enter into similar fee-based contracts with new customers in the future, our efforts to obtain such contractual terms may not be successful. For example, in the future we may enter into percent-of-

proceeds contracts with our customers, which would increase our exposure to commodity price risk, as the revenues generated from those contracts directly correlate with the fluctuating price of natural gas and natural gas liquids. Substantially all of our remaining revenue is derived from (i) the sale of physical natural gas that we retain from our DFW Midstream customers to offset our power expense associated with our electric-drive compression and (ii) the sale of condensate volumes that we collect on the Grand River system. The revenues we earn from the sale of retained natural gas are tied to the price of natural gas. In addition, changes in the price of oil could directly affect the revenues we receive from the sale of condensate.

Furthermore, we may acquire or develop additional midstream assets in the future, including assets related to commodities other than natural gas, that have a greater exposure to fluctuations in commodity price risk than our current operations. Future exposure to the volatility of oil and natural gas prices could have a material adverse effect on our business, results of operations and financial condition.

A change in laws and regulations applicable to our assets or services, or the interpretation or implementation of existing laws and regulations may cause our revenue to decline or our operating and maintenance expenses to increase.

Various aspects of our operations are subject to extensive and frequently changing regulation as the activities of the natural gas industry often are reviewed by legislators and regulators. More stringent legislation or regulation or taxation of natural gas drilling activity could directly curtail such activity or increase the cost of drilling, resulting in reduced levels of drilling activity and therefore reduced demand for our services. Numerous federal, state and local departments and agencies are authorized by statute to issue, and have issued, rules and regulations and interpretations binding upon participants in the natural gas industry. The agencies establish and from time to time change priorities, which may result in additional burdens on us, such as additional reporting requirements and more frequent audits of operations, which we have recently experienced relative to the DFW Midstream system. Our operations and the markets in which we participate are affected by these laws, regulations and interpretations and may be affected by changes to them or their implementation, which may cause us to realize materially lower revenues or incur materially increased operating costs or both.

Increased regulation of hydraulic fracturing could result in reductions or delays in natural gas production by our customers, which could materially adversely impact our revenues.

A substantial majority of our customers' natural gas production is developed from unconventional sources, such as shales, that require hydraulic fracturing as part of the completion process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into the formation to stimulate gas production. We do not engage in any hydraulic fracturing activities although many of our customers do. Legislation to amend the Safe Drinking Water Act to repeal the exemption for hydraulic fracturing from the definition of underground injection and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, were proposed in recent sessions of the U.S. Congress. Congress will likely continue to consider legislation to amend the Safe Drinking Water Act to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. Any such legislation could make it easier for third parties opposed to hydraulic fracturing to initiate legal proceedings against our customers.

Scrutiny of hydraulic fracturing activities continues in other ways, with both regulatory and study initiatives. For example, in May 2012, the Department of the Interior's Bureau of Land Management issued a proposed rule to regulate hydraulic fracturing on public and Indian land. The rule would require companies to publicly disclose to the Bureau of Land Management the chemicals used in hydraulic fracturing operations after fracturing operations have been completed and includes provisions addressing well-bore integrity and flowback water management plans. In addition, the EPA has commenced a multi-year study of the potential environmental impacts of hydraulic fracturing, the final results of which are expected in 2014. Similarly, in October 2011, the EPA announced its intention to propose regulations by 2014 under the federal Clean Water Act to develop standards for wastewater discharges from hydraulic fracturing and other natural gas production activities. In addition to the EPA, the White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the U.S. House of Representatives has conducted an investigation of hydraulic fracturing practices. The

U.S. Department of Energy is conducting an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic fracturing completion methods. Certain members of Congress have called upon:

- the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources;
- the Securities and Exchange Commission to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing; and
- the U.S. Energy Information Administration to provide a better understanding of that agency's estimates regarding natural-gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates.

Depending on the outcome of these studies and other initiatives, federal and state legislatures and agencies may seek to further regulate hydraulic fracturing activities.

Several states, including Texas and Colorado in which our customers do business, have also proposed or adopted legislative or regulatory restrictions on hydraulic fracturing. The chemical ingredient information for hydraulic fracturing fluid is generally available to the public through online databases, and this availability may bring more public scrutiny to hydraulic fracturing operations. We cannot predict whether any other legislation will be enacted and if so, what its provisions would be. If additional levels of regulation and permits were required through the adoption of new laws and regulations at the federal or state level, that could lead to delays, increased operating costs and prohibitions for producers who drill near our pipelines which could reduce the volumes of natural gas available to move through our gathering systems, and thus materially adversely affect our revenue and results of operations and ability to make cash distributions.

In April 2012, the EPA approved final rules that would subject all oil and natural gas operations (production, processing, transmission, storage and distribution) to regulation under the NSPS and National Emission Standards for Hazardous Air Pollutants programs. These rules also include NSPS standards for completions of hydraulically fractured gas wells. These standards include the reduced emission completion techniques developed in the EPA's Natural Gas STAR program along with pit flaring of gas not sent to the gathering line. The standards would be applicable to newly drilled and fractured wells as well as existing wells that are refractured. Further, the proposed regulations under the National Emission Standards for Hazardous Air Pollutants program include maximum achievable control technology standards for those glycol dehydrators and storage vessels at major sources of hazardous air pollutants not currently subject to maximum achievable control technology standards. At this point, the effect these proposed rules could have on our business has not been determined. While these rules have been finalized, many of the rules' provisions will be phased in over time, with the more stringent requirements like reduced emission completion not becoming effective until 2015.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and natural gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to increased operating costs in the production of oil and natural gas, or could make it more difficult to perform hydraulic fracturing, either of which could have an adverse effect on our customers. The adoption of any federal, state or local laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and natural gas wells, increased compliance costs and time, which could adversely affect our financial position, results of operations and cash flows.

We are subject to federal anti-market manipulation laws and regulations, potentially other federal regulatory requirements, and state and local regulation, and could be materially affected by changes in such laws and regulations, or in the way they are interpreted and enforced.

We believe that our pipeline facilities qualify as gathering facilities that are exempt from the jurisdiction of FERC, the NGA and the NGPA. We are, however, subject to the anti-market manipulation provisions in the NGA, as amended by the Energy Policy Act of 2005, and to FERC's regulations thereunder, which authorize FERC to impose fines of up to $1,000,000 per day per violation of the NGA or its implementing regulations. In addition, the Federal Trade Commission holds statutory authority under the Energy Independence and Security Act of 2007 to prevent market manipulation in oil markets, and has adopted broad rules and regulations prohibiting fraud and market manipulation. The Federal Trade Commission is also authorized to seek fines of up to $1,000,000 per violation. The Commodity Futures Trading Commission is directed under the Commodity Exchange Act, to prevent price manipulations for the commodity and futures markets, including the energy futures markets. Pursuant to the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010, also known as the Dodd-Frank Act, and other authority, the Commodity Futures Trading Commission has adopted anti-market manipulation regulations that prohibit fraud and price manipulation in the commodity and futures markets. The Commodity Futures Trading Commission also has statutory authority to seek civil penalties of up to the greater of $1,000,000 per day per violation or triple the

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monetary gain to the violator for each violation of the anti-market manipulation sections of the Commodity Exchange Act.

The distinction between federally unregulated gathering facilities and FERC-regulated transmission pipelines has been the subject of extensive litigation and may be determined by FERC on a case-by-case basis, although FERC has made no determinations as to the status of our facilities. Consequently, the classification and regulation of some of our pipelines could change based on future determinations by FERC or the courts. If our gas gathering operations become subject to FERC jurisdiction, the result may materially adversely affect the rates we are able to charge and the services we currently provide, and may include the potential for a termination of our gathering agreements with our customers.

We are subject to state and local regulation regarding the construction and operation of our gathering systems, as well as state ratable take statutes and regulations. Regulation of the construction and operation of our facilities may affect our ability to expand our facilities or build new facilities and such regulation may cause us to incur additional operating costs or limit the quantities of gas we may gather. Ratable take statutes and regulations generally require gatherers to take natural gas production that may be tendered for gathering without undue discrimination. These requirements restrict our right to decide whose production we gather. Many states have adopted complaint-based regulation of gathering activities, which allows producers and shippers to file complaints with state regulators in an effort to resolve access issues, rate grievances, and other matters. Other state and municipal regulations do not directly apply to our business, but may nonetheless affect the availability of natural gas for gathering, including state regulation of production rates, maximum daily production allowable from gas wells, and other activities related to drilling and operating wells. While our facilities currently are subject to limited state and local regulation, there is a risk that state or local laws will be changed or reinterpreted, which may materially affect our operations, operating costs, and revenues.

We are subject to stringent laws and regulations that may expose us to significant costs and liabilities.

Our natural gas gathering, compression and dehydrating operations are subject to stringent and complex federal, state and local environmental laws and regulations, including laws and regulations regarding the discharge of materials into the environment or otherwise relating to environmental protection. Examples of these laws include:

- the federal Clean Air Act and analogous state laws that impose obligations related to air emissions;
- the federal Comprehensive Environmental Response, Compensation, and Liability Act, also known as CERCLA or the Superfund law, and analogous state laws that regulate the cleanup of hazardous substances that may be or have been released at properties currently or previously owned or operated by us or at locations to which our wastes are or have been transported for disposal;
- the federal Water Pollution Control Act, also known as the Clean Water Act, and analogous state laws that regulate discharges from our facilities into state and federal waters, including wetlands;
- the federal Oil Pollution Act and analogous state laws that establish strict liability for releases of oil into waters of the United States;
- the federal Resource Conservation and Recovery Act and analogous state laws that impose requirements for the storage, treatment and disposal of solid and hazardous waste from our facilities;
- the Endangered Species Act; and
- the Toxic Substances Control Act, and analogous state laws that impose requirements on the use, storage and disposal of various chemicals and chemical substances at our facilities.

These laws and regulations may impose numerous obligations that are applicable to our operations, including the acquisition of permits to conduct regulated activities, the incurrence of capital or operating expenditures to limit or prevent releases of materials from our pipelines and facilities, and the imposition of substantial liabilities and remedial obligations for pollution resulting from our operations or at locations currently or previously owned or operated by us. Numerous governmental authorities, such as the EPA and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly corrective actions or costly pollution control measures. Failure to comply with these laws, regulations and requisite permits may result in the assessment of significant administrative, civil and criminal penalties, the imposition of remedial obligations and the issuance of injunctions limiting or preventing some or all of our operations. In addition, we may experience a delay in obtaining or be unable to obtain required permits or regulatory authorizations, which may cause us to lose potential and current customers, interrupt our operations and limit our growth and revenue.

There is a risk that we may incur significant environmental costs and liabilities in connection with our operations due to historical industry operations and waste disposal practices, our handling of hydrocarbons and other wastes and potential emissions and discharges related to our operations. Joint and several, strict liability may be incurred, without regard to fault, under certain of these environmental laws and regulations in connection with discharges or releases of hydrocarbon wastes on, under or from our properties and facilities, many of which have been used for midstream activities for a number of years, oftentimes by third parties not under our control. Private parties, including the owners of the properties through which our gathering systems pass and facilities where our wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. For example, an accidental release from one of our pipelines could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage and fines or penalties for related violations of environmental laws or regulations. In addition, changes in environmental laws occur frequently, and any such changes that result in additional permitting obligations or more stringent and costly waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on our operations or financial position. We may not be able to recover all or any of these costs from insurance.

We may incur greater than anticipated costs and liabilities as a result of pipeline safety requirements.

The U.S. Department of Transportation, through its Pipeline and Hazardous Materials Safety Administration, has adopted and enforces safety standards and procedures applicable to our pipelines. In addition, many states, including the states in which we operate, have adopted regulations similar to existing U.S. Department of Transportation regulations for intrastate pipelines. Among the regulations applicable to us, the Pipeline and Hazardous Materials Safety Administration requires pipeline operators to develop integrity management programs for certain pipelines located in high consequence areas, which include high population areas such as the Dallas-Fort Worth greater metropolitan area where our DFW Midstream system is located. While the majority of our pipelines meet the U.S. Department of Transportation definition of gathering lines and are thus exempt from the Pipeline and Hazardous Materials Safety Administration's integrity management requirements, we also operate three pipelines in the Dallas-Fort Worth area that are subject to the integrity management requirements. The regulations require operators, including us, to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact a high consequence area;
- maintain processes for data collection, integration and analysis;
- repair and remediate pipelines as necessary;
- adopt and maintain procedures, standards and training programs for control room operations; and
- implement preventive and mitigating actions.

Our pipelines have become subject to regulation which has increased penalties assessed against violators and may become subject to more stringent safety regulation.

Recently enacted pipeline safety legislation, the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, reauthorizes funding for federal pipeline safety programs through 2015, increases penalties for safety violations, establishes additional safety requirements for newly constructed pipelines, and requires studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines. The Pipeline and Hazardous Materials Safety Administration has also published an advanced notice of proposed rulemaking to solicit comments on the need for changes to its safety regulations, including whether to revise the integrity management requirements and extend the integrity management requirements to certain gathering lines. A new interpretation of existing laws and regulations could also significantly increase our costs or materially affect our operations. For example, Pipeline and Hazardous Materials Safety Administration issued an Advisory Bulletin which, among other things, advises pipeline operators that if they are relying on design, construction, inspection, testing or other data to determine the pressures at which their pipelines should operate, the records of that data must be traceable, verifiable and complete. Locating such records and, in the absence of any such records, verifying maximum pressures through physical testing or modifying or replacing facilities to meet the demands of such pressures, could significantly increase our costs. Additionally, failure to locate such records or verify maximum pressures could result in reductions of allowable operating pressures, which would reduce available capacity of our pipelines. While we believe that we are in compliance with existing safety laws and regulations, increased penalties for safety violations and potential regulatory changes could have a material adverse effect on our operations, operating and maintenance expenses, and revenues. Extending the integrity management requirements to our gathering lines would impose additional obligations on us and could add material costs to our operations.

Climate change legislation, regulatory initiatives and litigation could result in increased operating costs and reduced demand for the natural gas services we provide.

In recent years, the U.S. Congress has considered legislation to restrict or regulate emissions of greenhouse gases, such as carbon dioxide and methane that may be contributing to global warming. It presently appears unlikely that comprehensive climate legislation will be passed by either house of Congress in the near future, although energy legislation and other initiatives are expected to be proposed that may be relevant to greenhouse gas emissions issues. In addition, almost half of the states, either individually or through multi-state regional initiatives, have begun to address greenhouse gas emissions, primarily through the planned development of emission inventories or regional greenhouse gas 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 gas processing plants, to acquire and surrender emission allowances. In general, the number of allowances available for purchase is reduced each year until the overall greenhouse gas emission reduction goal is achieved. Depending on the scope of a particular program, we could be required to purchase and surrender allowances for greenhouse gas emissions resulting from our operations (e.g., at compressor stations). Although most of the state-level initiatives have to date been focused on large sources of greenhouse gas emissions, such as electric power plants, it is possible that our sources, such as our gas-fired compressors, could become subject to state-level greenhouse gas-related regulation. Depending on the particular program, we may be required to control emissions or to purchase and surrender allowances for greenhouse gas emissions resulting from our operations.

Independent of Congress, the EPA has begun to adopt federal-level regulations controlling greenhouse gas emissions under its existing Clean Air Act authority. In 2009, the EPA issued required findings under the Clean Air Act concluding that emissions of greenhouse gases present an endangerment to human health and the environment, and issued a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States beginning in 2011 for emissions occurring in 2010. In May 2010, the EPA issued a final rule, also known as the Tailoring Rule, that makes certain large stationary sources and modification projects subject to permitting requirements for greenhouse gas emissions under the Clean Air Act. In November 2010, the EPA also issued a final rule expanding its existing greenhouse gas emissions reporting rule for petroleum and natural gas facilities. These rules require data collection beginning in 2011 and reporting beginning in September 2012 and require that we report our greenhouse gas emissions for certain of our assets. As a result of this continued regulatory focus, future greenhouse gas regulation of the oil and gas industry remain a possibility.

Although it is not possible at this time to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions would impact our business, either directly or indirectly, any future federal or state laws or implementing regulations that may be adopted to address greenhouse gas emissions could require us to incur increased operating costs and could materially adversely affect demand for the natural gas we gather or otherwise handle in connection with our services. The potential increase in the costs of our operations resulting from any legislation or regulation to restrict emissions of greenhouse gases could include new or increased costs to operate and maintain our facilities, install new emission controls on our facilities, acquire allowances to authorize our greenhouse gas emissions, pay any taxes related to our greenhouse gas emissions and administer and manage a greenhouse gas emissions program. While we may be able to include some or all of such increased costs in the rates charged by our pipelines or other facilities, such recovery of costs is uncertain. Moreover, incentives to conserve energy or use alternative energy sources could reduce demand for natural gas, resulting in a decrease in demand for our services. We cannot predict with any certainty at this time how these possibilities may affect our operations.

The adoption and implementation of new statutory and regulatory requirements for swap transactions could have an adverse impact on our ability to hedge risks associated with our business and increase the working capital requirements to conduct these activities.

Congress adopted comprehensive financial reform legislation under the Dodd-Frank Act that establishes federal oversight and regulation of the over-the-counter, or OTC, derivatives market and entities, such as us, that participate in that market. This legislation requires the Commodities Futures Trading Commission and the Securities and Exchange Commission to promulgate certain rules and regulations, including rules and regulations relating to the regulation of certain swaps entities, the clearing of certain swaps, the reporting and recordkeeping of swaps, and expanded enforcement such as establishing position limits. Although the Commodities Futures Trading Commission established position limits on certain core futures and equivalent swaps contracts, including natural gas, with exceptions for certain bona fide hedging transactions, those limits were vacated by federal district court on September 28, 2012, and will not go into effect until the Commodities Futures Trading Commission prevails on appeal of this ruling, or issues and finalizes revised rules.

In December 2012, the Commodities Futures Trading Commission published final rules regarding mandatory clearing of four classes of interest rate swaps and two classes of credit swaps and setting compliance dates of March 11, 2013, June 10, 2013, and, for end users of swaps, September 9, 2013. We currently receive a fuel retainage fee from certain of our customers that is paid in-kind to offset the costs we incur to operate our electric-drive compression assets in the Barnett Shale. We currently enter into forward contracts with third parties to buy power and sell natural gas in an attempt to hedge our exposure to fluctuations in the price of natural gas with respect to those volumes. The impact of the Dodd-Frank Act on our hedging activities is uncertain at this time. However, the new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks that we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. The Dodd-Frank Act may also materially affect our customers and materially and adversely affect the demand for our services.

We do not own all of the land on which our pipelines and facilities are located, which could result in disruptions to our operations.

We do not own all of the land on which our pipelines and facilities have been constructed, and we are, therefore, subject to the possibility of more onerous terms and/or increased costs to retain necessary land use if we do not have valid rights-of-way or if such rights-of-way lapse or terminate or if our pipelines are not properly located within the boundaries of such rights-of-way. We obtain the rights to construct and operate our pipelines on land owned by third parties and governmental agencies for a specific period of time. If we were to be unsuccessful in renegotiated rights-of-way, we might have to relocate our facilities. Our loss of these rights, through our inability to renew right-of-way contracts or otherwise, could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

Our ability to operate our business effectively could be impaired if we fail to attract and retain key management personnel.

Our ability to operate our business and implement our strategies will depend on our continued ability to attract and retain highly skilled management personnel with midstream natural gas industry experience and competition for these persons in the midstream natural gas industry is intense. Given our size, we may be at a disadvantage, relative to our larger competitors, in the competition for these personnel. We may not be able to continue to employ our senior executives and key personnel or attract and retain qualified personnel in the future, and our failure to retain or attract our senior executives and key personnel could have a material adverse effect on our ability to effectively operate our business.

If we fail to develop or maintain an effective system of internal controls, we may not be able to report our financial results timely and accurately or prevent fraud, which would likely have a negative impact on the market price of our common units.

As a publicly traded partnership, we are subject to the public reporting requirements of the Securities Exchange Act of 1934, as amended, including the rules thereunder that will require our management to certify financial and other information in our quarterly and annual reports and provide an annual management report on the effectiveness of our internal control over financial reporting. Effective internal controls are necessary for us to provide reliable and timely financial reports, prevent fraud and to operate successfully as a publicly traded partnership. We prepare our consolidated financial statements in accordance with generally accepted accounting principles, but our internal accounting controls may not meet all standards applicable to companies with publicly traded securities. Our efforts to develop and maintain our internal controls may not be successful and we may be unable to maintain effective controls over our financial processes and reporting in the future or to comply with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002.

Given the difficulties inherent in the design and operation of internal controls over financial reporting, in addition to our limited accounting personnel and management resources, we can provide no assurance as to our or our independent registered public accounting firm's future conclusions about the effectiveness of our internal controls, and we may incur significant costs in our efforts to comply with Section 404 of the Sarbanes-Oxley Act of 2002. Any failure to implement and maintain effective internal controls over financial reporting will subject us to regulatory

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scrutiny and a loss of confidence in our reported financial information, which could have an adverse effect on our business and would likely have a negative effect on the trading price of our common units.

Although we will be required to disclose changes made in our internal control and procedures on a quarterly basis, we will not be required to make our first annual assessment of our internal control over financial reporting pursuant to Section 404 of the Sarbanes-Oxley Act of 2002 until the fiscal year ending December 31, 2013. In addition, pursuant to the recently enacted Jumpstart Our Business Startups Act, also known as the JOBS Act, our independent registered public accounting firm will not be required to formally attest to the effectiveness of our internal control over financial reporting until the later of the year following our first annual report required to be filed with the Securities and Exchange Commission or the date we are no longer an emerging growth company.

The amount of cash we have available for distribution to holders of our common and subordinated units depends primarily on our cash flow rather than on our profitability, which may prevent us from making distributions, even during periods in which we record net income.

The amount of cash we have available for distribution depends primarily upon our cash flow and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record losses for financial accounting purposes and may not make cash distributions during periods when we record net earnings for financial accounting purposes.

Risks Inherent in an Investment in Us

Summit Investments owns and controls our general partner, which has sole responsibility for conducting our business and managing our operations as well as limited duties to us and our unitholders. Summit Investments and our general partner have conflicts of interest with us and they may favor their own interests to the detriment of us and our unitholders.

Summit Investments controls our general partner, and has authority to appoint all of the officers and directors of our general partner, some of whom will also be officers, directors or principals of Energy Capital Partners, one of the two entities that own Summit Investments. Although our general partner has a duty to manage us in a manner that is in our best interests, the directors and officers of our general partner also have a duty to manage our general partner in a manner that is in the best interests of its owner, Summit Investments. Conflicts of interest will arise between Summit Investments, its owners and our general partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of Summit Investments and its owners over our interests and the interests of our unitholders. These conflicts include the following situations, among others:

- Neither our partnership agreement nor any other agreement requires Summit Investments or its owners to pursue a business strategy that favors us, and the directors and officers of Summit Investments have a fiduciary duty to make these decisions in the best interests of the owners of Summit Investments, which may be contrary to our interests.
- Summit Investments may choose to shift the focus of its investment and growth to areas not served by our assets. Summit Investments is not limited in its ability to compete with us and may offer business opportunities or sell midstream assets to third parties without first offering us the right to bid for them.
- Our general partner is allowed to take into account the interests of parties other than us, such as Summit Investments and its owners, in resolving conflicts of interest.
- Our partnership agreement replaces the fiduciary duties that would otherwise be owed by our general partner to us and our unitholders with contractual standards governing its duties to us and our unitholders. These contractual standards limit our general partner's liabilities and the rights of our unitholders with respect to actions that, without the limitations, might constitute breaches of fiduciary duty.
- Except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval.
- Our general partner determines the amount and timing of asset purchases and sales, borrowings, issuance of additional partnership interests and the creation, reduction or increase of reserves, each of which can affect the amount of cash that is distributed to our unitholders.
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Our general partner determines the amount and timing of any capital expenditures and whether a capital expenditure is classified as a maintenance capital expenditure, which reduces operating surplus, or an

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expansion capital expenditure, which does not reduce operating surplus. This determination can affect the amount of cash that is distributed to our unitholders and to our general partner and the ability of the subordinated units to convert to common units.

- Our general partner determines which costs incurred by it are reimbursable by us.
- Our general partner may cause us to borrow funds to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make a distribution on the subordinated units, to make incentive distributions or to accelerate the expiration of the subordination period.
- Our partnership agreement permits us to classify up to $50.0 million as operating surplus, even if it is generated from asset sales, non-working capital borrowings or other sources that would otherwise constitute capital surplus. This cash may be used to fund distributions on our subordinated units or to our general partner in respect of the general partner interest or the incentive distribution rights.
- Our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf.
- Our general partner intends to limit its liability regarding our contractual and other obligations.
- Our general partner may exercise its right to call and purchase all of the common units not owned by it and its affiliates if they own more than 80% of the common units.
- Our general partner controls the enforcement of the obligations that it and its affiliates owe to us.
- Our general partner decides whether to retain separate counsel, accountants or others to perform services for us.
- Our general partner may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to our general partner's incentive distribution rights without the approval of the conflicts committee of the board of directors of our general partner or our unitholders. This election may result in lower distributions to our other unitholders in certain situations.

Our Sponsors are not limited in their ability to compete with us and are not obligated to offer us the opportunity to acquire additional assets or businesses, which could limit our ability to grow and could materially adversely affect our results of operations and cash available for distribution to our unitholders.

Energy Capital Partners and GE Energy Financial Services have significantly greater resources than us and have experience making investments in midstream energy businesses. Energy Capital Partners and GE Energy Financial Services may compete with us for investment opportunities and may own interests in entities that compete with us. Energy Capital Partners and GE Energy Financial Services are not prohibited from owning assets or engaging in businesses that compete directly or indirectly with us. For example, GE Energy Financial Services owns an interest in another midstream publicly traded partnership. In addition, in the future, Energy Capital Partners or GE Energy Financial Services may acquire, construct or dispose of additional midstream or other assets and may be presented with new business opportunities, without any obligation to offer us the opportunity to purchase or construct such assets or to engage in such business opportunities. For example, in October 2012, Summit Investments acquired a natural gas gathering and processing system in the Piceance and Uinta basins in Colorado and Utah from a third party. In February 2013, Summit Investments acquired a midstream energy company that owns, operates and is developing various natural gas gathering and processing assets along with crude oil and water gathering assets in multiple locations outside of our current operating areas. While Summit Investments may offer us the opportunity to buy these or other additional assets, it is not under any contractual obligation to do so and we are unable to predict whether or when such opportunities may arise.

Pursuant to the terms of our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, does not apply to our general partner, its officers and directors or any of its affiliates, including our Sponsors and their respective executive officers, directors and principals. Any such person or entity that becomes aware of a potential transaction, agreement, arrangement or other matter that may be an opportunity for us will not have any duty to communicate or offer such opportunity to us. Any such person or entity will not be liable to us or to any limited partner for breach of any fiduciary duty or other duty by reason of the fact that such person or entity pursues or acquires such opportunity for itself, directs such opportunity to another person or entity or does not communicate such opportunity or information to us. This may create actual and potential conflicts of interest between us and affiliates of our general partner and result in less than favorable treatment of us and our unitholders.

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The market price of our common units may fluctuate significantly and, due to limited daily trading volumes, an investor could lose all or part of its investment in us.

There were 14,382,577 publicly traded common units at December 31, 2012. In addition, Summit Investments, which also controls our general partner, owned 10,029,850 common and 24,409,850 subordinated units. An investor may not be able to resell its common units at or above its acquisition price. Additionally, a lack of liquidity may result in wide bid-ask spreads, contribute to significant fluctuations in the market price of the common units and limit the number of investors who are able to buy the common units.

The market price of our common units may decline and be influenced by many factors, some of which are beyond our control, including:

- our quarterly distributions;
- our quarterly or annual earnings or those of other companies in our industry;
- the loss of a large customer;
- announcements by us or our competitors of significant contracts or acquisitions;
- changes in accounting standards, policies, guidance, interpretations or principles;
- general economic conditions;
- the failure of securities analysts to cover our common units or changes in financial estimates by analysts;
- future sales of our common units; and
- other factors described in these Risk Factors.

Our partnership agreement replaces our general partner's fiduciary duties to holders of our common and subordinated units with contractual standards governing its duties.

Our partnership agreement contains provisions that eliminate fiduciary duties to which our general partner would otherwise be held by state fiduciary duty law and replaces those duties with several different contractual standards. For example, our partnership agreement permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner or otherwise, free of any duties to us and our unitholders, other than the implied contractual covenant of good faith and fair dealing. This entitles our general partner to consider only the interests and factors that it desires and relieves it of any duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or our limited partners. Examples of decisions that our general partner may make in its individual capacity include:

- how to allocate corporate opportunities among us and its affiliates;
- whether to exercise its limited call right;
- whether to seek approval of the resolution of a conflict of interest by the conflicts committee of the board of directors of our general partner;
- how to exercise its voting rights with respect to the units it owns;
- whether to exercise its registration rights;
- whether to elect to reset target distribution levels;
- whether to transfer the incentive distribution rights or any units it owns to a third party; and
- whether or not to consent to any merger or consolidation of the partnership or amendment to the partnership agreement.

By purchasing a common unit, a common unitholder agrees to become bound by the provisions in the partnership agreement, including the provisions discussed above.

Our partnership agreement limits the liabilities of our general partner and the rights of our unitholders with respect to actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that limit the liability of our general partner and the rights of our unitholders with respect to actions taken by our general partner that might otherwise constitute breaches of fiduciary duty under state fiduciary duty law. For example, our partnership agreement provides that:

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- whenever our general partner makes a determination or takes, or declines to take, any other action in its capacity as our general partner, our general partner is required to make such determination, or take or decline to take such other action, in good faith, meaning that it subjectively believed that the decision was in our best interests, and will not be subject to any other or different standard imposed by our partnership agreement, Delaware law, or any other law, rule or regulation, or at equity;
- our general partner will not have any liability to us or our unitholders for decisions made in its capacity as a general partner so long as such decisions are made in good faith;
- our general partner and its officers and directors will not be liable for monetary damages to us, our limited partners or their assignees resulting from any act or omission unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our general partner or its officers and directors, as the case may be, acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal; and
- our general partner will not be in breach of its obligations under the partnership agreement or its duties to us or our unitholders if a transaction with an affiliate or the resolution of a conflict of interest is:

(i) approved by the conflicts committee of the board of directors of our general partner, although our general partner is not obligated to seek such approval;

(ii) approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner and its affiliates;

(iii) on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or

(iv) fair and reasonable to us, taking into account the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to us.

In connection with a situation involving a transaction with an affiliate or a conflict of interest, any determination by our general partner or the conflicts committee must be made in good faith. If an affiliate transaction or the resolution of a conflict of interest is not approved by our common unitholders or the conflicts committee and the board of directors of our general partner determines that the resolution or course of action taken with respect to the affiliate transaction or conflict of interest satisfies either of the standards set forth in the final two subclauses above, then it will be presumed that, in making its decision, the board of directors acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the partnership, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Our general partner intends to limit its liability regarding our obligations.

Our general partner intends to limit its liability under contractual arrangements so that the counterparties to such arrangements have recourse only against our assets, and not against our general partner or its assets. Our general partner may therefore cause us to incur indebtedness or other obligations that are nonrecourse to our general partner. Our partnership agreement provides that any action taken by our general partner to limit its liability is not a breach of our general partner's fiduciary duties, even if we could have obtained more favorable terms without the limitation on liability. In addition, we are obligated to reimburse or indemnify our general partner to the extent that it incurs obligations on our behalf. Any such reimbursement or indemnification payments would reduce the amount of cash otherwise available for distribution to our unitholders.

Our partnership agreement requires that we distribute all of our available cash, which could limit our ability to grow and make acquisitions.

We expect that we will distribute all of our available cash to our unitholders and will rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund our acquisitions and expansion capital expenditures. As a result, to the extent we are unable to finance growth externally, our cash distribution policy will significantly impair our ability to grow.

In addition, because we intend to distribute all of our available cash, we may not grow as quickly as businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per-unit distribution level. There are no limitations in our partnership agreement or our amended and restated revolving credit facility on our ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial

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borrowings or other debt to finance our growth strategy would result in increased interest expense, which, in turn, may impact the available cash that we have to distribute to our unitholders.

While our partnership agreement requires us to distribute all of our available cash, our partnership agreement, including provisions requiring us to make cash distributions contained therein, may be amended.

While our partnership agreement requires us to distribute all of our available cash, our partnership agreement, including provisions requiring us to make cash distributions contained therein, may be amended. Our partnership agreement generally may not be amended during the subordination period without the approval of our public common unitholders. However, our partnership agreement can be amended with the consent of our general partner and the approval of a majority of the outstanding common units (including common units held by affiliates of our general partner) after the subordination period has ended. As of December 31, 2012, Summit Investments, which also controls our general partner, owned 10,029,850 common units and all of our 24,409,850 outstanding subordinated units.

Reimbursements due to our general partner and its affiliates for services provided to us or on our behalf will reduce cash available for distribution to our common unitholders. The amount and timing of such reimbursements will be determined by our general partner.

Prior to making any distribution on our common units, we will reimburse our general partner and its affiliates, including Summit Investments, for expenses they incur and payments they make on our behalf. Under our partnership agreement, we will reimburse our general partner and its affiliates for certain expenses incurred on our behalf, including administrative costs, such as compensation expense for those persons who provide services necessary to run our business. Our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us. The reimbursement of expenses and payment of fees, if any, to our general partner and its affiliates will reduce the amount of available cash to pay cash distributions to our unitholders.

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

Our general partner has the right, at any time when there are no subordinated units outstanding and it has received incentive distributions at the highest level to which it is entitled (48.0%) for each of the prior four consecutive fiscal quarters (and the amount of each such distribution did not exceed adjusted operating surplus for such quarter), to reset the initial target distribution levels at higher levels based on our cash distribution at the time of the exercise of the reset election. Following a reset election by our general partner, the minimum quarterly distribution will be reset to an amount equal to the average cash distribution per unit for the two fiscal quarters immediately preceding the reset election (such amount is referred to as the reset minimum quarterly distribution), and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution.

In the event of a reset of target distribution levels, our general partner will be entitled to receive the number of common units equal to that number of common units that would have entitled it to an average aggregate quarterly cash distribution in the prior two quarters equal to the average of the distributions on the incentive distribution rights in the prior two quarters. Our general partner will also be issued the number of general partner units necessary to maintain its general partner interest in us that existed immediately prior to the reset election. We anticipate that our general partner would exercise this reset right to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per common unit without such conversion; however, it is possible that our general partner could exercise this reset election at a time when we are experiencing declines in our aggregate cash distributions or at a time when our general partner expects that we will experience declines in our aggregate cash distributions in the foreseeable future. In such situations, our general partner may be experiencing, or may expect to experience, declines in the cash distributions it receives related to its incentive distribution rights and may therefore desire to be issued common units, which are entitled to specified priorities with respect to our distributions and which therefore may be more advantageous for the general partner to own in lieu of the right to receive incentive distribution payments based on target distribution levels that are less certain to be achieved in the then-current business environment. As a result, a reset election may cause our common unitholders to experience dilution in the amount of cash distributions that they would have otherwise received had we not issued common units to our general partner in connection with resetting the target distribution levels related to our general partner's incentive distribution rights.

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

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Unitholders will have no right on an annual or ongoing basis to elect our general partner or its board of directors. The board of directors of our general partner will be chosen by Summit Investments. Furthermore, if the unitholders are dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. As a result of these limitations, the price at which the common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price. Our partnership agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management.

Even if holders of our common units are dissatisfied, they cannot initially remove our general partner without its consent.

The unitholders initially will be unable to remove our general partner without its consent because our general partner and its affiliates own sufficient units to be able to prevent its removal. The vote of the holders of at least $66^2/3\%$ of all outstanding limited partner units voting together as a single class is required to remove our general partner. As of December 31, 2012, Summit Investments, which also controls our general partner, owned 10,029,850 common units and 24,409,850 subordinated units, or 70.5% of our outstanding limited partner units. Also, if our general partner is removed without cause during the subordination period and units held by our general partner and its affiliates are not voted in favor of that removal, all remaining subordinated units will automatically convert into common units and any existing arrearages on our common units will be extinguished. A removal of our general partner under these circumstances would materially adversely affect our common units by prematurely eliminating their distribution and liquidation preference over our subordinated units, which would otherwise have continued until we had met certain distribution and performance tests. Cause is narrowly defined to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding our general partner liable for actual fraud or willful or wanton misconduct in its capacity as our general partner. Cause does not include most cases of charges of poor management of the business, so the removal of our general partner because of the unitholder's dissatisfaction with our general partner's performance in managing our partnership will most likely result in the termination of the subordination period and conversion of all subordinated units to common units.

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

Unitholders' voting rights are further restricted by a provision of our partnership agreement providing that any person or group that owns 20% or more of any class of units then outstanding cannot vote on any matter, other than our general partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the board of directors of our general partner.

Our general partner interest or the control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, our partnership agreement does not restrict the ability of Summit Investments to transfer all or a portion of its ownership interest in our general partner to a third party. The new owner of our general partner would then be in a position to replace the board of directors and officers of our general partner with its own designees and thereby exert significant control over the decisions made by the board of directors and officers. This effectively permits a change of control without the vote or consent of the unitholders.

The incentive distribution rights of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer the incentive distribution rights it owns to a third party at any time without the consent of our unitholders. If our general partner transfers the incentive distribution rights to a third party but retains its general partner interest, our general partner may not have the same incentive to grow our business and increase quarterly distributions to unitholders over time as it would if it had retained ownership of the incentive distribution rights. For example, a transfer of the incentive distribution rights by our general partner could reduce the likelihood of

Summit Investments selling or contributing additional midstream assets to us, as Summit Investments would have less of an economic incentive to grow our business, which in turn would impact our ability to grow our asset base.

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

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

- our existing unitholders' proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- because a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by our common unitholders will increase;
- because the amount payable to holders of incentive distribution rights is based on a percentage of the total cash available for distribution, the distributions to holders of incentive distribution rights will increase even if the per-unit distribution on common units remains the same;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

Summit Investments may sell units in the public or private markets, and such sales could have an adverse impact on the trading price of the common units.

As of December 31, 2012, Summit Investments held an aggregate of 10,029,850 common units and 24,409,850 subordinated units. All of the subordinated units will convert into common units at the end of the subordination period. In addition, we have agreed to provide Summit Investments with certain registration rights. The sale of these units in the public or private markets could have an adverse impact on the price of the common units or on any trading market that may develop.

Our general partner has a limited call right that may require an investor to sell its units at an undesirable time or price.

If at any time our general partner and its affiliates own more than 80% of our outstanding common units, our general partner will have the right, which it may assign to any of its affiliates or to us, but not the obligation, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price that is not less than their then-current market price, as calculated pursuant to the terms of our partnership agreement. As a result, an investor may be required to sell its common units at an undesirable time or price and may not receive any return on its investment. An investor may also incur a tax liability upon a sale of its units. As of December 31, 2012, Summit Investments owned 10,029,850 common units. At the end of the subordination period, assuming no acquisitions, dispositions, retirement or additional issuances of common units (other than upon the conversion of the subordinated units), Summit Investments will own 34,439,700 common units, or approximately 70.5% of our then-outstanding common units.

An investor's liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law, and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. An investor could be liable for any and all of our obligations as if it was a general partner if a court or government agency were to determine that:

- we were conducting business in a state but had not complied with that particular state's partnership statute; or
- an investor's right to act with other unitholders to remove or replace our general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitute control of our business.

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

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Delaware Law, we may not make a distribution if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of an impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Substituted limited partners are liable both for the obligations of the assignor to make contributions to the partnership that were known to the substituted limited partner at the time it became a limited partner and for those obligations that were unknown if the liabilities could have been determined from the partnership agreement. Neither liabilities to partners on account of their partnership interest nor liabilities that are non-recourse to the partnership are counted for purposes of determining whether a distribution is permitted.

If an investor is not an eligible holder, it may not receive distributions or allocations of income or loss on those common units and those common units will be subject to redemption.

We have adopted certain requirements regarding those investors who may own our common and subordinated units. Eligible holders are U.S. individuals or entities subject to U.S. federal income taxation on the income generated by us or entities not subject to U.S. federal income taxation on the income generated by us, so long as all of the entity's owners are U.S. individuals or entities subject to such taxation. If an investor is not an eligible holder, our general partner may elect not to make distributions or allocate income or loss on that investor's units, and it runs the risk of having its units redeemed by us at the lower of purchase price cost and the then-current market price. The redemption price may be paid in cash or by delivery of a promissory note, as determined by our general partner.

The New York Stock Exchange does not require a publicly traded partnership like us to comply with certain of its corporate governance requirements.

We have listed our common units on the New York Stock Exchange. Because we are a publicly traded partnership, the New York Stock Exchange does not require us to have, and we do not intend to have, a majority of independent directors on our general partner's board of directors or to establish a compensation committee or a nominating and corporate governance committee. Additionally, any future issuance of additional common units or other securities, including to affiliates, will not be subject to the New York Stock Exchange's shareholder approval rules. Accordingly, unitholders will not have the same protections afforded to certain corporations that are subject to all of the New York Stock Exchange corporate governance requirements.

We will incur increased costs as a result of being a publicly traded partnership.

We have limited history operating as a publicly traded partnership. As a publicly traded partnership, we will incur significant legal, accounting and other expenses. In addition, Section 404 of the Sarbanes-Oxley of 2002 and related rules subsequently implemented by the Securities and Exchange Commission and the New York Stock Exchange have required changes in the corporate governance practices of publicly traded companies. We expect these rules and regulations to increase our legal and financial compliance costs and to make activities more time-consuming and costly. For example, as a result of becoming a publicly traded partnership, we are required to have at least three independent directors, create an audit committee and adopt policies regarding internal controls and disclosure controls and procedures, including the preparation of reports on internal controls over financial reporting. In addition, we will incur additional costs associated with our publicly traded partnership reporting requirements. We also expect these new rules and regulations to make it more difficult and more expensive for our general partner to obtain director and officer liability insurance and to possibly result in our general partner having to accept reduced policy limits and coverage. As a result, it may be more difficult for our general partner to attract and retain qualified persons to serve on its board of directors or as executive officers.

Tax Risks

Our tax treatment depends on our status as a partnership for federal income tax purposes. If the Internal Revenue Service (the "IRS") were to treat us as a corporation for federal income tax purposes, which would subject us to entity-level taxation, then our cash available for distribution to our unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested a ruling from the IRS on this or any other tax matter affecting us.

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Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. A change in current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity. If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state and local income tax at varying rates. Distributions would generally be taxed again as corporate dividends (to the extent of our current and accumulated earnings and profits), and no income, gains, losses, deductions, or credits would flow through to unitholders. Because a tax would be imposed upon us as a corporation, our cash available for distribution would be substantially reduced. Therefore, if we were treated as a corporation for federal income tax purposes, there would be material reduction in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units.

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

If we were subjected to a material amount of additional entity-level taxation by individual states, it would reduce our cash available for distribution to our unitholders.

Changes in current state law may subject us to additional entity-level taxation by individual states. 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. Imposition of any such taxes may substantially reduce the cash available for distribution. Our partnership agreement provides that, if a law is enacted or existing law is modified or interpreted in a manner that subjects us to entity-level taxation, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

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

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. For example, from time to time members of the U.S. Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships. We are unable to predict whether any such changes will ultimately be enacted. However, it is possible that a change in law could affect us and may be applied retroactively. Any such changes could negatively impact the value of an investment in our common units.

Our unitholders' share of our income will be taxable to them for federal income tax purposes even if they do not receive any cash distributions from us.

Because a unitholder will be treated as a partner to whom we will allocate taxable income that could be different in amount than the cash we distribute, a unitholder's allocable share of our taxable income will be taxable to it, which may require the payment of federal income taxes and, in some cases, state and local income taxes, on its share of our taxable income even if the unitholder receives no cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from that income.

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

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes. The IRS may adopt positions that differ from the conclusions of our counsel or from the positions we take, and the IRS's positions may ultimately be sustained. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel's conclusions or the positions we take and such positions may not ultimately be sustained. A court may not agree with some or all of our counsel's conclusions or the positions we take. Any contest with the IRS, and the outcome of any IRS contest, may have an adverse impact on the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne

indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution.

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

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

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

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

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

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

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

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

A unitholder whose common units are loaned to a short seller to effect a short sale of common units may be considered as having disposed of those common units. If so, he would no longer be treated for federal income tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss from the disposition.

Because a unitholder whose common units are loaned to a short seller to effect a short sale of common units may be considered as having disposed of the loaned common units, he may no longer be treated for federal income tax purposes as a partner with respect to those common units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are advised to consult a tax advisor to discuss whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from loaning their common units.

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

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

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

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

We will be considered to have technically terminated our partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once. Our technical termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1 if relief was not available, as described below) for one fiscal year and would result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead we would be treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred. The IRS has recently announced a publicly traded partnership technical termination relief program whereby, if a publicly traded partnership that technically terminated requests publicly traded partnership technical termination relief and such relief is granted by the IRS, among other things, the partnership will only have to provide one Schedule K-1 to unitholders for the year notwithstanding two partnership tax years.

As a result of investing in our common units, you may become subject to state and local taxes and return filing requirements in jurisdictions where we operate or own or acquire properties.

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or control property now or in the future, even if the unitholders do not live in any of those jurisdictions. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We initially expect to conduct business in Texas and Colorado. Colorado currently imposes a personal income tax on individuals. As we make acquisitions or expand our business, we may control assets or conduct business in additional states that impose a personal income tax. It is the unitholder's responsibility to file all federal, state and local tax returns.

Item 1B. Unresolved Staff Comments.
Not applicable.

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Item 2. Properties.

We currently have two natural gas gathering systems which provide our gathering, compression and dehydration services. They are the Grand River system located primarily in Garfield County, Colorado and the DFW Midstream system located primarily in Tarrant County, Texas. For additional information on our gathering systems and their capacities, see Item 1. Business.

Our real property falls into two categories: (i) parcels that we own in fee and (ii) parcels in which our interest derives from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities, permitting the use of such land for our operations. Portions of the land on which our gathering systems and other major facilities are located are owned by us in fee title, and we believe that we have satisfactory title to these lands. The remainder of the land on which our major facilities are located are held by us pursuant to perpetual easements between us and the underlying fee owner, or permits with governmental authorities. Our Predecessor leased or owned these lands without any material challenge known to us relating to the title to the land upon which our assets are located, and we believe that we have satisfactory leasehold estates or fee ownership in such lands or valid permits with governmental authorities. We have no knowledge of any material challenge to the underlying fee title of any material lease, easement, right-of-way, permit or license held by us or to our title to any material lease, easement, right-of-way, permit or license. We believe that we have satisfactory title to all of our material leases, easements, rights-of-way, permits and licenses with the exception of certain ordinary course encumbrances and permits with governmental entities that have been applied for, but not yet issued.

In addition, we lease various office space under operating leases to support our operations. Our headquarters are located in Dallas, Texas, and we have additional regional offices in Houston, Texas, Denver, Colorado and Atlanta, Georgia.

Item 3. Legal Proceedings.

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, except as described below, we are not currently a party to any significant legal or governmental proceedings. In addition, we are not aware of any significant legal or governmental proceedings contemplated to be brought against us, under the various environmental protection statutes to which we are subject.

On August 21, 2012, four former DFW Midstream employees (the "Plaintiffs") who, by virtue of their Class B membership in DFW Midstream Management LLC ("DFW Management"), collectively own an aggregate 4.1% vested net profits interests in DFW Midstream Services LLC ("DFW Midstream"), filed a claim in the Court of Chancery of the State of Delaware against Summit Investments, Summit Holdings, DFW Midstream and DFW Management (collectively, the "Defendants") seeking dissolution and wind-up of DFW Midstream and DFW Management or, in the alternative, a repurchase of the Plaintiffs' net profits interests. The Plaintiffs also seek other unspecified monetary damages, including attorneys' fees and costs. The complaint alleges that the Defendants breached (i) the DFW Midstream limited liability company agreement; (ii) compensatory arrangements with each Plaintiff; (iii) the implied covenant of good faith and fair dealing; and (iv) in the case of Summit Investments and Summit Holdings, their alleged fiduciary duties to the Plaintiffs. The complaint further alleges that the Defendants acted fraudulently with respect to the Plaintiffs. On September 28, 2012, the Defendants filed a motion to dismiss all of Plaintiffs’ claims in this matter. The court heard oral arguments on the motion to dismiss on December 12, 2012, and a decision on the motion is expected in the first half of 2013. The court has stayed discovery pending its resolution of Defendants’ motion to dismiss.

While we are unable to predict the outcome of this litigation, we believe that the Plaintiffs' allegations are meritless. We intend to vigorously defend ourselves against these allegations, and we do not believe that the dispute, even if determined adversely against us, would have a material effect on our financial position, results of operations or cash flows.

Item 4. Mine Safety Disclosures.

Not applicable.

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PART II

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

Our limited partner common units began trading on the New York Stock Exchange commencing with our initial public offering on September 28, 2012 at a price of $20.00 per common unit. Our ticker symbol is "SMLP." As of February 28, 2013, the market price for our common units was $22.52 per unit and there were approximately 2,500 common unitholders, including beneficial owners of common units held in street name. There is one record holder of our subordinated units. There is no established public trading market for our subordinated units.

The following table shows the high and low price per common unit, as reported by the New York Stock Exchange for the periods indicated.

	Common unit price range		Cash distribution paid per common unit
	High	Low	
4th Quarter 2012	$21.50	$18.26	—
3rd Quarter 2012	$21.48	$20.57	—

There were no cash distributions paid during the third and fourth quarters of 2012. On January 23, 2013, the board of directors of our general partner declared a distribution of $0.41 per unit for the quarterly period ended December 31, 2012. The distribution, which totaled approximately $20.4 million, was paid on February 14, 2013 to unitholders of record at the close of business on February 7, 2013.

Our Cash Distribution Policy and Restrictions on Distributions

General

Our Cash Distribution Policy. Our partnership agreement requires us to distribute all of our available cash quarterly. Our policy is to distribute to our unitholders an amount of cash each quarter that is equal to or greater than the minimum quarterly distribution stated in our partnership agreement. Generally, our available cash is our (i) cash on hand at the end of a quarter after the payment of our expenses and the establishment of cash reserves and (ii) cash on hand resulting from working capital borrowings made after the end of the quarter. Because we are not subject to an entity-level federal income tax, we have more cash to distribute to our unitholders than would be the case were we subject to federal income tax. For additional information, see Note 7 to the audited consolidated financial statements.

Limitations on Cash Distributions and Our Ability to Change Our Cash Distribution Policy. There is no guarantee that our unitholders will receive quarterly distributions from us. We do not have a legal obligation to pay the minimum quarterly distribution or any other distribution except to the extent we have available cash as defined in our partnership agreement. Our cash distribution policy may be changed at any time and is subject to certain restrictions, including the following:

- Our cash distribution policy is subject to restrictions on distributions under our amended and restated revolving credit facility. Our amended and restated revolving credit facility contains financial tests and covenants that we must satisfy. Should we be unable to satisfy these restrictions, we may be prohibited from making cash distributions notwithstanding our stated cash distribution policy.
- Our general partner has the authority to establish cash reserves for the prudent conduct of our business and for future cash distributions to our unitholders, and the establishment or increase of those cash reserves could result in a reduction in cash distributions to you from the levels we currently anticipate pursuant to our stated distribution policy. Any determination to establish cash reserves made by our general partner in good faith will be binding on our unitholders.
- Although our partnership agreement requires us to distribute all of our available cash, our partnership agreement, including the provisions requiring us to distribute all of our available cash, may be amended. Our partnership agreement generally may not be amended during the subordination period without the approval of our public common unitholders other than in certain limited circumstances where no unitholder approval is required. However, our partnership agreement can be amended with the consent of our general partner and the approval of a majority of the outstanding common units (including common units held by Summit Investments) after the subordination period has

ended. As of February 28, 2013, Summit

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Investments owned our general partner as well as approximately 41.1% of our outstanding common units and all of our subordinated units, representing an aggregate 70.5% limited partner interest in us.

- Even if our cash distribution policy is not modified or revoked, the amount of distributions we pay under our cash distribution policy and the decision to make any distribution is determined by our general partner, taking into consideration the terms of our partnership agreement.
- Under Delaware law, we may not make a distribution if the distribution would cause our liabilities to exceed the fair value of our assets.
- We may lack sufficient cash to pay distributions to our unitholders due to cash flow shortfalls attributable to a number of operational, commercial or other factors as well as increases in our operating or general and administrative expenses, principal and interest payments on our debt, tax expenses, working capital requirements and anticipated cash needs. Our cash available for distribution to unitholders is directly impacted by our cash expenses necessary to run our business and will be reduced dollar-for-dollar to the extent such uses of cash increase.
- If and to the extent our cash available for distribution materially declines, we may elect to reduce our quarterly distribution rate to service or repay our debt or fund expansion capital expenditures.

Our Minimum Quarterly Distribution

The board of directors of our general partner has established a minimum quarterly distribution of $0.40 per unit per quarter, or $1.60 per unit per year, to be paid no later than 45 days after the end of each fiscal quarter beginning with the quarter ending December 31, 2012. This equates to an aggregate cash distribution of approximately $20.0 million per quarter, or approximately $79.9 million per year, based on all of the units outstanding as of February 28, 2013. Our general partner is entitled to 2.0% of all distributions that we make prior to our liquidation. In the future, our general partner's initial 2.0% interest in these distributions may be reduced if we issue additional units and our general partner does not contribute a proportionate amount of capital to us to maintain its 2.0% general partner interest.

The following table sets forth the number of common and subordinated units outstanding as of February 28, 2013 and the number of unit equivalents represented by the 2.0% general partner interest and the aggregate distribution amounts payable on such units during the year at our minimum quarterly distribution rate of $0.40 per unit per quarter, or $1.60 per unit on an annualized basis.

	Minimum Quarterly Distribution		
	Number of units	Per quarter	Annualized
	(Dollars in thousands)		
Publicly held common units	14,382,577	$5,753	$23,012
Common units held by Summit Investments	10,029,850	4,012	16,048
Subordinated units held by Summit Investments	24,409,850	9,764	39,056
Long-term incentive plan participant units	131,558	53	210
2.0% general partner interest	996,320	399	1,594
Total	49,950,155	$19,980	$79,920

The subordination period generally will end if we have earned and paid at least $1.60 on each outstanding common unit and subordinated unit and the corresponding distribution on our general partner's 2.0% interest for each of three consecutive, non-overlapping four-quarter periods ending on or after December 31, 2015. The subordination period will automatically terminate and all of the subordinated units will convert into an equal number of common units if we have earned and paid at least $2.40 (150.0% of the annualized minimum quarterly distribution) on each outstanding common unit and subordinated unit and the corresponding distribution on our general partner's 2.0% interest and the related distribution on the incentive distribution rights for any four consecutive quarter period ending on or after December 31, 2013.

If we do not pay the minimum quarterly distribution on our common units, our common unitholders will not be entitled to receive such payments in the future except during the subordination period. To the extent we have available cash in any future quarter during the subordination period in excess of the amount necessary to pay the minimum quarterly distribution to holders of our common units, we will use this excess available cash to pay any

distribution arrearages related to prior quarters before any cash distribution is made to holders of subordinated units. Our subordinated units will not accrue arrearages for unpaid quarterly distributions or quarterly distributions less than the minimum quarterly distribution.

Our cash distribution policy, as expressed in our partnership agreement, may not be modified or repealed without amending our partnership agreement. The actual amount of our cash distributions for any quarter is subject to fluctuations based on the amount of cash we generate from our business and the amount of reserves our general partner establishes in accordance with our partnership agreement as described above. We will pay our distributions on or about the 15th of each of February, May, August and November to holders of record on or about seven days prior to such distribution date. We will make the distribution on the business day immediately preceding the indicated distribution date if the distribution date falls on a holiday or non-business day.

Stock Performance Table

The following graph compares the performance of our common units since the IPO to the S&P 500 and the Alerian MLP Index by assuming $100 was invested in each investment option as of September 28, 2012, the date of the IPO. The Alerian MLP Index is a composite of the 50 most prominent energy Master Limited Partnerships, or MLPs, and is calculated using a float-adjusted, capitalization-weighted methodology.

Issuer Purchases of Equity Securities

We made no repurchases of our common units during the quarter ended December 31, 2012.

Equity Compensation Plans

The information relating to SMLP’s equity compensation plans required by Item 5 is included in Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

Item 6. Selected Financial Data.

SMLP completed its IPO on October 3, 2012. For the purposes of these financial statements, SMLP's results of operations for the year ended December 31, 2012 include the Predecessor's results of operations through the date of our IPO. The Grand River system was acquired on October 27, 2011. We have included its financial results in the financial statements of SMLP and the Predecessor since the date of acquisition. On September 3, 2009, Summit Investments acquired a controlling interest in DFW Midstream. We refer to DFW Midstream as our Initial Predecessor for the period prior to such date.

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The selected consolidated financial data presented as of December 31, 2012, 2011, 2010 and 2009 and for the years ended December 31, 2012, 2011, 2010 and for the period from September 3, 2009 to December 31, 2009 have been derived from the audited consolidated financial statements of SMLP and its Predecessor.

The selected financial data for the period from January 1, 2009 to September 3, 2009 have been derived from the audited financial statements of our Initial Predecessor. The historical consolidated financial statements and related notes of our Initial Predecessor:

(i) have been carved out of the accounting records maintained by Energy Future Holdings and its subsidiaries. Certain accounts such as trade accounts receivables, accounts payable, prepaid expenses and certain accrued liabilities relating to the activities of our Initial Predecessor were recorded on the books of other Energy Future Holdings entities and estimates of those accounts have been included in the consolidated financial statements;

(ii) include an estimate for general and administrative expenses, as Energy Future Holdings did not allocate any of the central finance and administrative costs to this operating entity;

(iii) reflect the operation of the DFW Midstream system with different business strategies and as part of a larger business rather than the stand-alone fashion in which we operate it; and

(iv) do not include any results from certain natural gas gathering assets that we acquired from Chesapeake on September 3, 2009 that are included in the DFW Midstream system.

Due to the various asset acquisitions and the associated shift in business strategies relative to those of the Predecessor and Initial Predecessor, SMLP's financial position and results of operations may not be comparable to the historical financial position and results of operations of the Predecessor and the Initial Predecessor.

The following table presents selected balance sheet data as of the date indicated.

	December 31,			
	2012	2011	2010	2009
	(In thousands)			
Balance Sheet Data:				
Cash and cash equivalents	$7,895	$15,462	$9,421	$39,455
Accounts receivable	33,504	27,476	10,238	1,373
Property, plant and equipment, net	681,993	638,190	277,765	140,704
Total assets	1,063,511	1,030,264	340,095	215,982
Total debt	199,230	349,893	—	—
Partners' capital	819,247	n/a	n/a	n/a
Membership interests	n/a	640,818	307,370	185,066

n/a - Not applicable

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The following table presents selected statement of operations data by entity for the periods indicated.

	SMLP				Initial Predecessor
	Year ended December 31,			Period from September 3, 2009 to December 31, 2009	Period from January 1, 2009 to September 3, 2009
	2012	2011	2010		
	(In thousands, except per-unit amounts)				
Statement of Operations Data:					
Revenue:					
Gathering services and other fees	$149,371	$91,421	$29,358	$1,714	$1,910
Natural gas and condensate sales	16,320	12,439	2,533	—	—
Amortization of favorable and unfavorable contracts	(192)	(308)	(215)	19	—
Total revenue	165,499	103,552	31,676	1,733	1,910
Costs and expenses:					
Operations and maintenance	51,658	29,855	9,503	1,147	1,010
General and administrative	21,357	17,476	10,035	2,939	600
Transaction costs (1)	2,020	3,166	—	3,921	—
Depreciation and amortization	35,299	11,367	3,874	343	882
Total costs and expenses	110,334	61,864	23,412	8,350	2,492
Other income	9	12	32	18	—
Interest expense	(7,340)	(1,029)	—	—	(247)
Affiliated interest expense	(5,426)	(2,025)	—	—	—
Income before income taxes	42,408	38,646	8,296	(6,599)	(829)
Income tax expense	(682)	(695)	(124)	(7)	(8)
Net income	$41,726	$37,951	$8,172	$(6,606)	$(837)
Less: net income attributable to the pre-IPO period	24,112				
Net income attributable to the post-IPO period	17,614				
Less: net income attributable to the general partner	352				
Net income attributable to the limited partners	$17,262				
Earnings per common unit – basic	$0.35				
Earnings per common unit – diluted	$0.35				
Earnings per subordinated unit – basic and diluted	$0.35				

(1) In 2012, includes transaction expenses of $0.3 million related to the acquisition of Grand River Gathering and $1.7 million related to Summit Investments' acquisition of ETC Canyon Pipeline, LLC ("Red Rock"). Red Rock was not contributed to SMLP in connection with the IPO and is not an asset of SMLP. In 2011, includes transaction expenses of $3.2 million related to the acquisition of Grand River Gathering. In 2009, includes transaction expenses of $3.9 million that were incurred in connection with the Predecessor's formation and initial assets acquisition. These expenses include an aggregate of $2.2 million paid to Energy Capital Partners and $1.7 million paid to third parties for

strategic, advisory, management, legal, and consulting services.

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The following table presents selected other financial data by entity for the periods indicated.

	SMLP				Initial Predecessor
	Year ended December 31,			Period from September 3, 2009 to December 31, 2009	Period from January 1, 2009 to September 3, 2009
	2012	2011	2010		
	(In thousands, except for per-unit amounts)				
Other Financial Data:					
EBITDA	$90,656	$53,363	$12,353	$(6,293)	$300
Adjusted EBITDA	103,300	56,803	12,353	(6,293)	300
Capital expenditures	76,698	78,248	153,719	19,519	40,777
Acquisition capital expenditures	—	589,462	—	44,896	—
Distributable cash flow	88,492	50,980	11,726	(6,275)	300
Distributions declared per unit (1)	0.41	n/a	n/a	n/a	n/a

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(1) Represents the distribution declared on January 25, 2013 for the quarter ended December 31, 2012
n/a - Not applicable
For a detailed discussion of the data presented above, including information regarding our use of EBITDA, adjusted EBITDA and distributable cash flow as well as their reconciliations to net income and net cash flows provided by operating activities, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations. The preceding tables should also be read in conjunction with the audited consolidated financial statements and related notes.

Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations.
MD&A is intended to inform the reader about matters affecting the financial condition and results of operations of SMLP and its subsidiaries and its Predecessor for the three-year period ended December 31, 2012. As a result, the following discussion should be read in conjunction with the audited consolidated financial statements and related notes that are included herein. Among other things, those financial statements and the related notes include more detailed information regarding the basis of presentation for the following information. This discussion contains forward-looking statements that constitute our plans, estimates and beliefs. These forward-looking statements involve numerous risks and uncertainties, including, but not limited to, those discussed in "Risk Factors." Actual results may differ materially from those contained in any forward-looking statements.

Overview
We are a growth-oriented limited partnership focused on owning and operating midstream energy infrastructure assets that are strategically located in the core producing areas of unconventional resource basins, primarily shale formations, in North America. We currently provide fee-based natural gas gathering and compression services in two unconventional resource basins: (i) the Piceance Basin, which includes the Mesaverde formation and the Mancos and Niobrara shale formations in western Colorado; and (ii) the Fort Worth Basin, which includes the Barnett Shale formation in north-central Texas.
We generate a substantial majority of our revenue under long-term, fee-based natural gas gathering agreements. Substantially all of our gas gathering agreements are underpinned by areas of mutual interest and minimum volume commitments. Our areas of mutual interest cover approximately 330,000 acres in the aggregate, have original terms that range from six years to 24 years, and provide that any natural gas producing wells drilled by our customers within the areas of mutual interest will be shipped on our gathering systems. The minimum volume commitments, which totaled 2.4 Tcf at December 31, 2012 and average approximately 639 MMcf/d through 2020, are designed to ensure that we will generate a certain amount of revenue from each customer over the life of the respective gas gathering

agreement, whether by collecting gathering fees on actual throughput or from cash payments to cover any minimum volume commitment shortfall. Our minimum volume commitments have remaining terms that range

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from seven years to 15 years and, as of December 31, 2012, had a weighted average remaining life of 11.1 years, assuming minimum throughput volumes for the remainder of the term. The fee-based nature of these agreements enhances the stability of our cash flows by limiting our direct commodity price exposure.

Our Operations

Our results are driven primarily by the volumes of natural gas that we gather and compress across our systems. During the year ended December 31, 2012, we generated approximately 89% of our revenue from fee-based gathering services that we provided to our customers. During the same period, we generated approximately 11% of our revenue from (i) the sale of physical natural gas that we retained from our DFW Midstream customers to offset our power expense associated with the operation of our electric-drive compression and (ii) the sale of condensate volumes that we collected on our Grand River system. We also earn revenue by charging certain customers with respect to costs we incur on their behalf for carbon dioxide treating to deliver pipeline quality natural gas to third-party pipelines and costs we incur to operate electric-drive compression on the Grand River system.

We contract with producers to gather natural gas from pad sites and central receipt points connected to the Grand River and DFW Midstream systems. These receipt points are connected to our gathering pipelines through which we compress and dehydrate natural gas and deliver it to downstream pipelines for ultimate delivery to end users or third-party processing plants.

We currently provide substantially all of our gathering and compression services under long-term, fee-based gas gathering agreements, which limit our direct commodity price exposure. Under these agreements, we are paid a fixed fee based on the volume and thermal content of the natural gas we gather. We are party to eight long-term gas gathering agreements with producers in the Barnett Shale. In the Piceance Basin, we are a party to three long-term gas gathering agreements with Encana and six gas gathering agreements with five other producers, three of which are long-term agreements. These agreements provide us with a revenue stream that is not subject to direct commodity price risk, with the exception of the natural gas that we retain in-kind to offset the power costs we incur to operate our electric-drive compression assets on the DFW Midstream system.

We also have indirect exposure to changes in commodity prices in that persistent low commodity prices may cause our customers to delay drilling or temporarily shut in production, which would reduce the volumes of natural gas that we gather. If our customers delay drilling or temporarily shut-in production due to persistently low commodity prices, our minimum volume commitments assure us that we will receive a certain amount of revenue from our customers.

We gather gas from both dry gas and liquids-rich regions and we believe that our gathering systems are well positioned to capture additional volumes from increased producer activity in these regions in the future. Dry gas regions contain natural gas reserves that are primarily composed of methane. Liquids-rich regions include natural gas reserves that contain natural gas liquids in addition to methane.

In the Piceance Basin, our Grand River system benefits from its exposure to liquids-rich gas production from the Mesaverde formation. The attractive economics associated with the production from this formation, combined with our minimum volume commitments from major producers in the area, provide us with stable cash flows and visible growth in the future. In addition, certain of our customers have joint venture agreements in place that provide for the development of portions of the Piceance Basin in our areas of mutual interest utilizing third-party funds. We believe the drilling activity from these joint ventures will benefit our Grand River system. The Grand River system also serves the emerging Mancos and Niobrara shale formations, which we expect will become more active to the extent that natural gas prices increase.

The DFW Midstream system benefits from its areas of mutual interest that cover the most prolific dry gas area of the Barnett Shale. We believe that this area offers our customers a compelling opportunity to maximize drilling economics due to the high estimated ultimate recovery of natural gas per well and relatively low drilling costs when compared with other dry gas resource basins. While recent market prices for natural gas have resulted in reduced drilling activity in the Barnett Shale, a significant number of wells remain in various stages of completion in our areas of mutual interest and on pad sites that have already been connected to the DFW Midstream system. These wells represent an opportunity to increase throughput on the DFW Midstream system at minimal incremental capital costs. In addition, because of the urban environment in which the DFW Midstream system is located, we expect that this area will continue to be developed by our customers using a high-density pad site drilling strategy that is designed to support multiple wells from a single location. Instead of constructing pipelines to multiple wells, we connect to an individual pad site, some of which can accommodate up to 30 wells, and gather all of the natural gas produced at that site, thus minimizing our future capital expenditures. This pad site strategy substantially increases the efficiency of both the producers' drilling activities as well as our gathering activities and economics.

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Trends and Outlook

Our business has been, and we expect our future business to continue to be, affected by the key trends discussed below. 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.

Natural gas supply and demand dynamics. Natural gas continues to be a critical component of energy supply and demand in the United States. Recently, the price of natural gas has been at historically low levels, with the prompt month NYMEX natural gas futures price at $3.43 per MMBtu as of December 28, 2012, compared with a high of $13.58 per MMBtu in July 2008. The lower price of natural gas is due in part to increased production, especially from unconventional sources, such as natural gas shale plays, high levels of natural gas in storage, warm winter weather and the effects of the economic downturn starting in 2008. According to the U.S. Energy Information Administration (the "EIA"), average annual natural gas production in the United States increased 13.9% from 55.2 Bcf/d to 62.9 Bcf/d from 2008 to 2011. Over the same time period, natural gas consumption increased only 4.5% to 66.6 Bcf/d. Furthermore, the amount of natural gas in storage in the continental United States has increased from approximately 2.8 Tcf as of August 5, 2011 to approximately 3.2 Tcf as of August 3, 2012 due to the decisions of many producers to store natural gas in the expectation of higher prices in the future and the unseasonably warm winter of 2011-2012. In response to lower natural gas prices, the number of natural gas drilling rigs has declined from approximately 1,403 as of December 31, 2008 to approximately 392 as of December 28, 2012 according to Smith Bits, as a number of producers have curtailed their natural gas exploration and production activities. We believe that over the short term, until the supply overhang has been reduced and the economy sees more robust growth, natural gas prices are likely to be constrained.

Over the long term, we believe that the prospects for continued natural gas demand are favorable and will be driven by population and economic growth, as well as the continued displacement of coal-fired electricity generation by natural gas-fired electricity generation due to the low prices of natural gas and stricter government environmental regulations on the mining and burning of coal. For example, according to the EIA, in December 2008, 49% of the electricity in the United States was generated by coal-fired power plants and in December 2011, 39% of the electricity in the United States was generated by coal-fired power plants. In January 2012, the EIA projected total annual domestic consumption of natural gas to increase from approximately 22.9 Tcf in 2009 to approximately 26.6 Tcf in 2035. Consistent with the rise in consumption, the EIA projects that total domestic natural gas production will continue to grow through 2035 to 27.9 Tcf. We believe that increasing consumption of natural gas will continue to drive natural gas drilling and production over the long term throughout the United States.

Growth in production from U.S. shale plays. Over the past several years, a fundamental shift in production has emerged with the growth of natural gas production from unconventional resources (defined by the EIA as natural gas produced from shale formations and coalbeds). While the EIA expects total domestic natural gas production to grow from 20.6 Tcf in 2009 to 27.9 Tcf in 2035, it expects shale gas production to grow to 13.6 Tcf in 2035, or 49% of total U.S. dry gas production. Most of this increase is due to the emergence of unconventional natural gas plays and advances in technology that have allowed producers to extract significant volumes of natural gas from these plays at cost-advantaged per unit economics as compared to most conventional plays.

In recent years, well-capitalized producers have leased large acreage positions in the Piceance Basin, the Barnett Shale and other unconventional resource plays. To help fund their drilling program in many of these areas, including in the Piceance Basin and the Barnett Shale, a number of producers have also entered into joint venture arrangements with large international operators, industrial manufacturers and private equity sponsors. These producers and their joint venture partners have committed significant capital to the development of the Piceance Basin, the Barnett Shale and other unconventional resource plays, which we believe will result in sustained drilling activity.

As a result of the current low natural gas price environment, some natural gas producers have cut back or suspended their drilling operations in certain dry gas regions where the economics of natural gas production are less favorable. Drilling activities focused in liquids-rich regions have continued and, in some cases, have increased, as the high Btu content associated with liquids-rich production enhances overall drilling economics, even in a low natural gas price environment.

Interest rate environment. The credit markets recently have experienced near-record lows in interest rates. As the overall economy strengthens, it is likely that monetary policy will tighten, resulting in higher interest rates to counter possible inflation. This could affect our ability to access the debt capital markets to the extent we may need to in the

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future to fund our growth. In addition, interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. Although this could limit our ability to raise funds in the debt capital markets, we expect to remain competitive with respect to acquisitions and capital projects, as our competitors would face similar circumstances.

Rising operating costs and inflation. The current high level of crude oil and natural gas exploration, development and production activities across the United States has resulted in increased competition for personnel and equipment. This is causing increases in the prices we pay for labor, supplies and property, plant and equipment. An increase in the general level of prices in the economy could have a similar effect. We attempt to recover increased costs from our customers, but there may be a delay in doing so or we may be unable to recover all of these costs. To the extent we are unable to procure necessary supplies or recover higher costs, our operating results will be negatively impacted.

How We Evaluate Our Operations

We manage our business and analyze our results of operations as a single business segment. Our management uses a variety of financial and operational metrics to analyze our performance. We view these metrics as important factors in evaluating our profitability and review these measurements on a regular basis for consistency and trend analysis. These metrics include:

- throughput volume;
- operations and maintenance expenses;
- EBITDA and adjusted EBITDA; and
- distributable cash flow.

Throughput Volume

The volume of natural gas that we gather depends on the level of production from natural gas wells connected to the Grand River and DFW Midstream systems. Aggregate production volumes are impacted by the overall amount of drilling and completion activity, as production must be maintained or increased by new drilling or other activity, because the production rate of a natural gas well declines over time.

As a result, we must continually obtain new supplies of natural gas to maintain or increase the throughput volume on our systems. Our ability to maintain or increase throughput volumes from existing customers and obtain new supplies of natural gas is impacted by:

- successful drilling activity within our areas of mutual interest;
- the level of work-overs and recompletions of wells on existing pad sites to which our gathering systems are connected;
- the number of new pad sites in our areas of mutual interest awaiting connections;
- our ability to compete for volumes from successful new wells in the areas in which we operate outside of our existing areas of mutual interest; and
- our ability to gather natural gas that has been released from commitments with our competitors.

Operations and Maintenance Expenses

We seek to maximize the profitability of our operations in part by minimizing, to the extent appropriate, expenses directly tied to operating and maintaining our assets. Direct labor costs, compression costs, insurance costs, ad valorem and property taxes, repair and non-capitalized maintenance costs, integrity management costs, utilities and contract services comprise the most significant portion of our operations and maintenance expense. Other than utilities expense, these expenses are relatively stable and largely independent of volumes delivered through our gathering systems but may fluctuate depending on the activities performed during a specific period.

The majority of the compressors on our DFW Midstream system are electric driven and power costs are directly correlated to the run-time of these compressors, which depends directly on the volume of natural gas gathered. As part of our contracts with our DFW Midstream system customers, we physically retain a percentage of throughput volumes that we subsequently sell to offset the power costs we incur. In addition, we pass along the fees associated with costs we incur on behalf of certain DFW Midstream system customers to deliver pipeline quality

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natural gas to third-party pipelines. With respect to the Grand River system, we either (i) consume physical gas on the system to operate our gas-fired compressors or (ii) charge our customers for the power costs we incur to operate our electric-drive compressors.

EBITDA, Adjusted EBITDA and Distributable Cash Flow

We define EBITDA as net income, plus interest expense, income tax expense, and depreciation and amortization expense, less interest income and income tax benefit. We define adjusted EBITDA as EBITDA plus non-cash compensation expense and adjustments related to MVC shortfall payments. We define distributable cash flow as adjusted EBITDA plus cash interest income, less cash paid for interest expense and income taxes and maintenance capital expenditures.

EBITDA, adjusted EBITDA and distributable cash flow are used as supplemental financial measures by our management and by external users of our financial statements such as investors, commercial banks, research analysts and others.

EBITDA and adjusted EBITDA are used to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- the ability of our assets to generate cash sufficient to support our indebtedness and make cash distributions to our unitholders and general partner;
- our operating performance and return on capital as compared to those of other companies in the midstream energy sector, without regard to financing or capital structure; and
- the attractiveness of capital projects and acquisitions and the overall rates of return on alternative investment opportunities.

In addition, adjusted EBITDA is used to assess:

- the financial performance of our assets without regard to the impact of the timing of minimum volume commitments shortfall payments under our gas gathering agreements or the impact of non-cash compensation expense.

Distributable cash flow is used to assess:

- the ability of our assets to generate cash sufficient to support our indebtedness and make future cash distributions to our unitholders; and
- the attractiveness of capital projects and acquisitions and the overall rates of return on alternative investment opportunities.

Results of Operations

Items Affecting the Comparability of Our Financial Results

SMLP's future results of operations may not be comparable to the historical results of operations for the reasons described below:

- Based on the terms of our partnership agreement, we expect that we will distribute to our unitholders most of the cash generated by our operations. As a result, we expect to fund future capital expenditures from cash and cash equivalents on hand, cash flow generated from our operations, borrowings under our amended and restated revolving credit facility and future issuances of equity and debt securities. Prior to the IPO, we largely relied on internally generated cash flows and capital contributions from the Sponsors to satisfy our capital expenditure requirements.
- The historical results of operations may not be comparable to our future results of operations largely due to our IPO, which was completed on October 3, 2012. We anticipate incurring approximately $2.5 million (annualized) of general and administrative expenses attributable to operating as a publicly traded partnership.

Incremental public entity costs include:

(i) expenses associated with annual and quarterly reporting;

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(ii) tax return and Schedule K-1 preparation and distribution expenses;
(iii) Sarbanes-Oxley compliance expenses;
(iv) expenses associated with listing on the NYSE;
(v) independent auditor fees;
(vi) legal fees;
(vii) investor relations expenses;
(viii) registrar and transfer agent fees;
(ix) director and officer liability insurance costs; and
(x) director compensation.

These incremental general and administrative expenses are not reflected in the historical consolidated financial statements prior to the IPO.

- The historical consolidated financial statements and related notes:

(i) reflect a 75% ownership interest in the DFW Midstream system, which we acquired from Texas Competitive Electric Holdings Company LLC ("TCEH"), an indirect subsidiary of Energy Future Holdings, from September 4, 2009 to June 18, 2010, the date on which we purchased the remaining 25% membership interest from TCEH;
(ii) include charges associated with a transition services agreement that we entered into with Energy Future Holdings in 2009. Under the terms of the transition services agreement, we paid Energy Future Holdings $32,400 in 2012, $41,400 in 2011 and $137,726 in 2010; and
(iii) do not include any results of operations from the acquisition of the Grand River system prior to November 2011.

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Results of Operations — Combined Overview

The following table presents certain consolidated and other financial and operating data for the periods indicated.

	Year ended December 31,		
	2012	2011	2010
	(In thousands)		
Statement of Operations Data:			
Revenue:			
Gathering services and other fees	$149,371	$91,421	$29,358
Natural gas and condensate sales	16,320	12,439	2,533
Amortization of favorable and unfavorable contracts (1)	(192)	(308)	(215)
Total revenue	165,499	103,552	31,676
Costs and expenses:			
Operations and maintenance	51,658	29,855	9,503
General and administrative	21,357	17,476	10,035
Transaction costs	2,020	3,166	—
Depreciation and amortization	35,299	11,367	3,874
Total costs and expenses	110,334	61,864	23,412
Other income	9	12	32
Interest expense	(7,340)	(1,029)	—
Affiliated interest expense	(5,426)	(2,025)	—
Income before income taxes	42,408	38,646	8,296
Income tax expense	(682)	(695)	(124)
Net income	$41,726	$37,951	$8,172
Less: net income attributable to the pre-IPO period	24,112		
Net income attributable to the post-IPO period	17,614		
Less: net income attributable to the general partner	352		
Net income attributable to the limited partners	$17,262		
Other Financial Data (2):			
EBITDA (3)	$90,656	$53,363	$12,353
Adjusted EBITDA (3)	103,300	56,803	12,353
Capital expenditures (4)	76,698	78,248	153,719
Acquisition expenditures (4)	—	589,462	—
Distributable cash flow	88,492	50,980	11,726
Other Operating Data:			
Miles of pipeline (end of period)	399	372	83
Number of wells (end of period) (5)	2,134	1,964	160
Number of pad sites (end of period)	443	435	33
Aggregate average throughput (MMcf/d)	929	431	136

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(1) The amortization of favorable and unfavorable contracts relates to gas gathering agreements that were deemed to be above or below market at the acquisition of the DFW Midstream system. We amortize these contracts on a units-of-production basis over the life of the applicable contract. The life of the contract is the period over which the contract is expected to contribute directly or indirectly to our future cash flows.

(2) See "Non-GAAP Financial Measures" below for additional information on EBITDA, adjusted EBITDA and distributable cash flow as well as their reconciliations to the most directly comparable GAAP financial measure.

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(3) EBITDA and adjusted EBITDA included transaction costs of $2.0 million in 2012 and $3.2 million in 2011. In 2010, EBITDA and adjusted EBITDA included $1.8 million of settlement expenses. These unusual and non-recurring expenses were settled in cash.
(4) Capital expenditures do not include acquisition capital expenditures. In 2011, we acquired the Grand River system. In the fourth quarter of 2012, we began tracking maintenance capital expenditures for the purposes of calculating distributable cash flow. Prior to the fourth quarter of 2012, we did not distinguish between maintenance and expansion capital expenditures. Therefore, to calculate distributable cash flow, we have estimated the portion of these expenditures that were maintenance capital expenditures for periods prior to the fourth quarter of 2012.
(5) Excludes wells connected to nine central receipt points on the Grand River system that averaged 256 MMcf/d in 2012 and 44 MMcf/d in 2011.

Year Ended December 31, 2012 Compared with the Year Ended December 31, 2011

Volume. Our revenues are primarily attributable to the volume of natural gas that we gather and compress and the rates we charge for those services. Throughput volumes increased 497 MMcf/d, or 115%, to an average of 929 MMcf/d in 2012 from 431 MMcf/d in 2011 primarily due to the October 2011 acquisition of the Grand River system and the continued development of the DFW Midstream system. As of December 31, 2012, there were approximately 1,822 wells connected to the Grand River system and 289 miles of pipeline. For the year ended December 31, 2012, aggregate throughput averaged 575 MMcf/d on the Grand River system. There were 312 wells and 64 drilling pad sites connected to the DFW Midstream system as of December 31, 2012, compared with 276 wells and 58 drilling pad sites as of December 31, 2011. The DFW Midstream system included 110 miles of pipeline as of December 31, 2012, compared with 104 miles of pipeline at December 31, 2011. Average throughput volumes for the DFW Midstream system increased largely as a result of the continued build out and an increase in well connections.

Revenue. Total revenues increased $61.9 million to $165.5 million in 2012, compared with $103.6 million in 2011. The 60% increase in total revenue was largely driven by a 63% increase in gathering services and other fees, primarily as a result of the October 2011 acquisition of the Grand River system and increased throughput volumes on the DFW Midstream system. Gathering services and other fees increased $58.0 million to $149.4 million in 2012, compared with $91.4 million in 2011. Gathering services and other fee revenue also reflects the impact of a decrease in aggregate average throughput rates we charge our customers. The aggregate average throughput rate for year ended December 31, 2012 was approximately $0.41 per Mcf, compared with approximately $0.52 per Mcf for the year ended December 31, 2011. The year-over-year decline was largely as a result of the lower average gathering fee per Mcf on our Grand River system. Gas gathering revenue for the Grand River system was approximately $63.1 million in 2012, compared with $11.0 million in 2011. Natural gas and condensate sales increased 31% to $16.3 million in 2012, compared with $12.4 million in 2011, largely reflecting the contribution of the Grand River system. Revenue associated with condensate sales for the Grand River system was approximately $3.5 million in 2012, compared with $0.6 million in 2011.

Operations and Maintenance Expense. Operations and maintenance expense increased $21.8 million to $51.7 million in 2012, compared with $29.9 million in 2011. The 73% increase was largely a result of Grand River system expenses incurred in 2012, partially offset by a decline in expenses for the DFW Midstream system. The decrease in operations and maintenance expense for the DFW Midstream system was primarily the result of a $1.3 million decline in compressor contractor services in 2012 due to the transition to in-house compressor services during the first quarter of 2012. This decrease was offset by an increase in property taxes as a result of the continued development of the DFW Midstream system. Operations and maintenance expense for the Grand River system was $26.5 million in 2012, compared with $3.9 million in 2011.

General and Administrative Expense. General and administrative expense increased $3.9 million to $21.4 million in 2012, compared with $17.5 million in 2011. The 22% increase was largely driven by an increase of expenses due to the acquisition of the Grand River system in October 2011. This increase primarily reflects an increase in salaries and benefits due to increased headcount, an increase in insurance expenses primarily as a result of our growth, and an increase in professional services expenses. These increases were partially offset by a decrease in non-cash unit-based compensation.

Transaction Costs. Transaction costs were $2.0 million for the year ended December 31, 2012, of which $1.7 million related to Summit Investments' acquisition of Red Rock and $0.3 million related to the acquisition of the Grand River system. Red Rock was not contributed to SMLP in connection with the IPO and is not an asset of SMLP. EBITDA and adjusted EBITDA in 2011 included $3.2 million in transaction costs related to the acquisition of the Grand River system.

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Depreciation and Amortization Expense. Depreciation and amortization expense increased to $35.3 million in 2012 from $11.4 million in 2011 largely due to the acquisition of the Grand River system in October 2011 and additional assets placed into service in connection with the development of the DFW Midstream system during 2011. Depreciation and amortization expense for the Grand River system was $23.1 million in 2012, compared with $3.2 million in 2011.

Interest Expense and Affiliated Interest Expense. Interest expense was $7.3 million in 2012, compared with $1.0 million in 2011. The increase was primarily as a result of the higher 2012 balances on the revolving credit facility that we obtained in May 2011. Affiliated interest expense was $5.4 million in 2012, compared with $2.0 million in 2011, and related to the $200.0 million promissory notes that we issued to the Sponsors in connection with the acquisition of the Grand River system in October 2011. The promissory notes were partially prepaid in May 2012 with the remaining balance prepaid in July 2012.

Year Ended December 31, 2011 Compared with the Year Ended December 31, 2010

Volume. Our revenues are primarily attributable to the volume of natural gas that we gather and compress and the rates we charge for those services. Throughput volumes increased 296 MMcf/d, or 218%, from 136 MMcf/d for the year ended December 31, 2010 to 431 MMcf/d for the year ended December 31, 2011. This increase was due to the continued development of the DFW Midstream system. There were 276 wells and 58 drilling pad sites and 160 wells and 33 drilling pad sites connected to the DFW Midstream system as of December 31, 2011 and 2010, respectively. The DFW Midstream system included 104 miles and 83 miles of pipeline as of December 31, 2011 and December 31, 2010, respectively. Throughput volumes for the DFW Midstream system averaged 333 MMcf/d for the year ended December 31, 2011. We acquired the Grand River system in October 2011. Throughput volumes for the Grand River system averaged 586 MMcf/d for the two months that the Grand River system was included in our financial results for the year ended December 31, 2011.

Revenue. Total revenue increased $71.9 million, or 227%, from $31.7 million for the year ended December 31, 2010 to $103.6 million for the year ended December 31, 2011. Gathering services and other fees increased $62.1 million, or 211%, from $29.4 million for the year ended December 31, 2010 to $91.4 million for the year ended December 31, 2011. This increase was primarily the result of increased throughput volumes on the DFW Midstream system, offset by a decrease of $0.04 per Mcf, or 7%, in the average throughput rates from $0.56 per Mcf for the year ended December 31, 2010 to $0.52 per Mcf for the year ended December 31, 2011. This decrease is primarily due to the fact that the Grand River system generates a lower average gathering fee per Mcf than our DFW Midstream system. Gas gathering revenue for the Grand River system was $11.0 million for the two months that the Grand River system was included in our financial results for the year ended December 31, 2011. Natural gas and condensate sales increased $9.9 million, or 391%, from $2.5 million for the year ended December 31, 2010 to $12.4 million for the year ended December 31, 2011. The increase in revenue attributable to natural gas and condensate sales is primarily the result of increased sales of natural gas that we retain from our DFW Midstream customers to offset the costs we incur to operate our electric-drive compression assets in the Barnett Shale. Revenue associated with condensate sales for the Grand River system was $0.6 million for the two months ended December 31, 2011.

Operations and Maintenance Expense. Operations and maintenance expense increased $20.4 million, or 214%, from $9.5 million for the year ended December 31, 2010 to $29.9 million for the year ended December 31, 2011. This increase was primarily the result of increased throughput volumes on the DFW Midstream system. Utility expense for our electric drive compressors increased $9.1 million, or 206%, from $4.4 million for the year ended December 31, 2010 to $13.5 million for the year ended December 31, 2011 due to increased volumes and the associated increased power cost to operate the compression. Operations and maintenance expenses for the Grand River system were $3.9 million for the two months that the Grand River system was included in our financial results for the year ended December 31, 2011.

General and Administrative Expense. General and administrative expense increased $7.4 million, or 74%, to $17.5 million for the year ended December 31, 2011. We recorded non-cash compensation expense of $3.4 million for the year ended December 31, 2011 relative to profits interests held by certain members of management. We did not record non-cash compensation expense for the year ended December 31, 2010. Salary and benefit expenses increased $2.0 million, or 45%, from $4.3 million for the year ended December 31, 2010 to $6.3 million for the year ended December

31, 2011 due to increased headcount to support our growth. We did not have these expenses for the year ended December 31, 2010. Due diligence costs relative to potential asset acquisitions were $1.3 million in 2011 compared to insignificant due diligence costs in 2010. The increase in G&A expenses was offset by decreases in legal expenses for the year ended December 31, 2011 compared to the year ended December 31, 2010. Legal expenses decreased $2.0 million in 2011 primarily as the result of decreased legal activities relative to relationships with contractors and sub-contractors associated with the DFW Midstream system. We had $1.8 million in settlement expenses in 2010 related to a dispute with a contractor at the DFW Midstream system.

Transaction Costs. Transaction costs were $3.2 million for the year ended December 31, 2011. These transaction costs were primarily related to the acquisition of the Grand River system. We did not have transaction costs for the year ended December 31, 2010.

Depreciation and Amortization Expense. Depreciation and amortization expense increased $7.5 million, or 192%, from $3.9 million for the year ended December 31, 2010 to $11.4 million for the year ended December 31, 2011. This increase was primarily the result of the depreciation associated with additional assets placed into service in connection with the development of the DFW Midstream system in 2011. Depreciation and amortization expense for the Grand River system was $3.2 million for the two months that the Grand River system was included in our financial results for the year ended December 31, 2011.

Interest Expense and Affiliated Interest Expense. Interest expense increased $3.1 million for the year ended December 31, 2011. This increase was primarily the result of entering into our revolving credit facility in May 2011 and the related amortization of deferred loan costs of $0.6 million and the increased interest expense related to the issuance of $200 million of promissory notes to our Sponsors in connection with the acquisition of the Grand River system. We did not have a revolving credit facility or outstanding promissory notes in 2010 and, therefore, we had no interest expense for the year ended December 31, 2010.

Non-GAAP Financial Measures

EBITDA, adjusted EBITDA and distributable cash flow are not financial measures presented in accordance with accounting principles generally accepted in the United States of America ("GAAP"). We believe that the presentation of these non-GAAP financial measures provides useful information to investors in assessing our financial condition and results of operations.

Net income and net cash flows provided by (used in) operating activities are the GAAP financial measures most directly comparable to EBITDA, adjusted EBITDA and distributable cash flow. Our non-GAAP financial measures should not be considered as alternatives to the most directly comparable GAAP financial measure. Furthermore, each of these non-GAAP financial measures has limitations as an analytical tool because it excludes some but not all items that affect the most directly comparable GAAP financial measure. Some of these limitations include:

- certain items excluded from EBITDA, adjusted EBITDA and distributable cash flow are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure;
- EBITDA, adjusted EBITDA, and distributable cash flow do not reflect our cash expenditures or future requirements for capital expenditures or contractual commitments;
- EBITDA, adjusted EBITDA, and distributable cash flow do not reflect changes in, or cash requirements for, our working capital needs;
- although depreciation and amortization are non-cash charges, the assets being depreciated and amortized will often have to be replaced in the future, and EBITDA, adjusted EBITDA and distributable cash flow do not reflect any cash requirements for such replacements; and
- our computations of EBITDA, adjusted EBITDA and distributable cash flow may not be comparable to other similarly titled measures of other companies.

We compensate for the limitations of EBITDA, adjusted EBITDA and distributable cash flows as analytical tools by reviewing the comparable GAAP financial measures, understanding the differences between the financial measures and incorporating these data points into our decision-making process.

EBITDA, adjusted EBITDA or distributable cash flow should not be considered in isolation or as a substitute for analysis of our results as reported under GAAP. Because EBITDA, adjusted EBITDA and distributable cash flow may be defined differently by other companies in our industry, our definitions of these non-GAAP financial measures may not be comparable to similarly titled measures of other companies, thereby diminishing their utility.

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Net Income-Basis Non-GAAP Reconciliation. The following table presents a reconciliation of SMLP's net income to EBITDA, adjusted EBITDA and distributable cash flow for the periods indicated.

	Year ended December 31,		
	2012	2011	2010
	(In thousands)		
Reconciliation of Net Income to EBITDA, Adjusted EBITDA and Distributable Cash Flow:			
Net income	$41,726	$37,951	$8,172
Add:			
Interest expense	12,766	3,054	—
Income tax expense	682	695	124
Depreciation and amortization expense	35,299	11,367	3,874
Amortization of favorable and unfavorable contracts	192	308	215
Less:			
Interest income	9	12	32
EBITDA (1)	$90,656	$53,363	$12,353
Add:			
Non-cash compensation expense	1,876	3,440	—
Adjustments related to MVC shortfall payments (2)	10,768	—	—
Adjusted EBITDA (1)	$103,300	$56,803	$12,353
Add:			
Interest income	9	12	32
Less:			
Cash interest paid	8,283	2,463	—
Cash taxes paid	650	223	10
Maintenance capital expenditures (3)	5,884	3,149	649
Distributable cash flow	$88,492	$50,980	$11,726

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(1) EBITDA and adjusted EBITDA included transaction costs of $2.0 million in 2012 and $3.2 million in 2011. In 2010, EBITDA and adjusted EBITDA included $1.8 million of settlement expenses. These unusual and non-recurring expenses were settled in cash. For additional information, see "Results of Operations" above.
(2) Adjustments related to MVC shortfall payments account for (i) the net increases or decreases in deferred revenue for MVC shortfall payments and (ii) our inclusion of expected annual MVC shortfall payments. We include or will include a proportional amount of these historical or expected minimum volume commitment shortfall payments in each quarter prior to the quarter in which we actually receive the shortfall payment.
(3) Maintenance capital expenditures are cash expenditures (including expenditures for the addition or improvement to, or the replacement of, our capital assets or for the acquisition of existing, or the construction or development of new, capital assets) made to maintain our long-term operating income or operating capacity. In the fourth quarter of 2012, we began tracking maintenance capital expenditures for the purposes of calculating distributable cash flow. Prior to the fourth quarter of 2012, we did not distinguish between maintenance and expansion capital expenditures. Therefore, to calculate distributable cash flow, we have estimated the portion of these expenditures that were maintenance capital expenditures for periods prior to the fourth quarter of 2012.

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Cash Flow-Basis Non-GAAP Reconciliation. The following table presents a reconciliation of SMLP's net cash flows provided by operating activities to EBITDA, adjusted EBITDA and distributable cash flow for the periods indicated.

	Year ended December 31,		
	2012	2011	2010
	(In thousands)		
Reconciliation of Net Cash Flows Provided by Operating Activities to EBITDA, Adjusted EBITDA and Distributable Cash Flow:			
Net cash provided by operating activities	$89,488	$39,942	$9,553
Add:			
Interest expense (1)	5,838	469	—
Income tax expense	682	695	124
Changes in operating assets and liabilities	(3,467)	15,709	2,708
Less:			
Non-cash compensation expense	1,876	3,440	—
Interest income	9	12	32
EBITDA (2)	$90,656	$53,363	$12,353
Add:			
Non-cash compensation expense	1,876	3,440	—
Adjustments related to MVC shortfall payments (3)	10,768	—	—
Adjusted EBITDA (2)	$103,300	$56,803	$12,353
Add:			
Interest income	9	12	32
Less:			
Cash interest paid	8,283	2,463	—
Cash taxes paid	650	223	10
Maintenance capital expenditures (4)	5,884	3,149	649
Distributable cash flow	$88,492	$50,980	$11,726

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(1) Interest expense presented in the cash flow-basis non-GAAP reconciliation above differs from the interest expense presented in the net income-basis non-GAAP reconciliation presented earlier due to adjustments for amortization of deferred loan costs and paid in kind interest on the promissory notes payable to our Sponsors. For the year ended December 31, 2012, interest expense excluded $1.5 million of amortization of deferred loan costs and $5.4 million of paid in kind interest. For the year ended December 31, 2011, interest expense presented excluded $0.6 million of amortization of deferred loan costs and $2.0 million of paid in kind interest.
(2) EBITDA and adjusted EBITDA included transaction costs of $2.0 million in 2012 and $3.2 million in 2011. In 2010, EBITDA and adjusted EBITDA included $1.8 million of settlement expenses. These unusual and non-recurring expenses were settled in cash. For additional information, see "Results of Operations" above.
(3) Adjustments related to MVC shortfall payments account for (i) the net increases or decreases in deferred revenue for MVC shortfall payments and (ii) our inclusion of expected annual MVC shortfall payments. We include or will include a proportional amount of these historical or expected minimum volume commitment shortfall payments in each quarter prior to the quarter in which we actually receive the shortfall payment.
(4) Maintenance capital expenditures are cash expenditures (including expenditures for the addition or improvement to, or the replacement of, our capital assets or for the acquisition of existing, or the construction or development of new, capital assets) made to maintain our long-term operating income or operating capacity. In the fourth quarter of 2012, we began tracking maintenance capital expenditures for the purposes of calculating distributable cash flow. Prior to the fourth quarter of 2012, we did not distinguish between maintenance and expansion capital expenditures. Therefore, to calculate distributable cash flow, we have estimated the portion of these expenditures that were maintenance capital expenditures for periods prior to the fourth quarter of 2012.

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Liquidity and Capital Resources

Prior to our IPO, our sources of liquidity included cash generated from operations, equity investments by our Sponsors, and borrowings under the revolving credit facility. In October 2012, we completed an IPO of our common units. For additional information, see Note 1 to the audited consolidated financial statements. In the periods following the IPO, we expect our sources of liquidity to include:

- cash generated from operations;
- borrowings under the revolving credit facility; and
- additional issuances of debt and equity securities.

Cash Flows

The components of the change in cash and cash equivalents were as follows:

	Year ended December 31,		
	2012	2011	2010
	(In thousands)		
Net cash provided by (used in) operating activities	$89,488	$39,942	$9,553
Net cash provided by (used in) investing activities	(76,698)	(667,710)	(153,719)
Net cash provided by (used in) financing activities	(20,357)	633,809	114,132
Change in cash and cash equivalents	$(7,567)	$6,041	$(30,034)

Year Ended December 31, 2012 Compared with the Year Ended December 31, 2011. Cash flows from operating activities increased by $49.5 million in 2012 largely as result of the increase in volumes on the DFW Midstream system and the inclusion of a full year of Grand River system operations in 2012.

Cash flows used in investing activities decreased in 2012 primarily as a result of the acquisition of the Grand River system in 2011. Capital expenditures on the DFW Midstream system were $40.3 million in 2012, compared with $78.2 million in 2011. Capital expenditures for new projects on the Grand River system were $32.6 million in 2012.

Cash flows from financing activities in 2012 reflect the May 2012 borrowing of $163.0 million under the revolving credit facility, of which we used $160.0 million to prepay principal amounts outstanding under certain unsecured promissory notes payable to the Sponsors. In July 2012, we borrowed $50.0 million under the revolving credit facility and used $49.2 million of the proceeds to repay the balance of the unsecured promissory notes payable to the Sponsors. Cash flows provided by financing activities also reflect proceeds of $263.1 million from the issuance of our common units in connection with our IPO (including the proceeds from the exercise of the underwriters' option to purchase additional common units). We used $140.0 million of the IPO proceeds to pay down our revolving credit facility. We also paid $88.0 million to reimburse Summit Investments for certain capital expenditures it incurred with respect to assets it contributed to us and distributed $35.1 million to Summit Investments for the common units it sold from the units originally allocated to it in connection with the exercise of the underwriters' option to purchase additional common units. We also made additional repayments totaling $20.8 million under the revolving credit facility in 2012. Financing cash flows in 2012 included $3.3 million of deferred loan costs.

Cash flows from financing activities in 2011 include $200.0 million of proceeds from the execution of promissory notes payable to the Sponsors to fund a portion of the purchase of the Grand River system. They also include $410.0 million of contributions from the Sponsors to acquire the Grand River system and $15.0 million to support capital needs related to the construction of the DFW Midstream system. Additionally, the Predecessor made a distribution to Energy Capital Partners of $132.9 million out of the $147.0 million drawn on the revolving credit facility. The Predecessor incurred $5.2 million of deferred loan costs in 2011.

Year Ended December 31, 2011 Compared with the Year Ended December 31, 2010. Cash flows from operating activities increased by $30.4 million, or 318%, to $40.0 million in 2011 from $9.6 million in 2010. The increase in cash flows from operating activities was a direct result of the significant increase in volumes on the DFW Midstream system during 2011, compared with 2010 and the inclusion of two months of operations on the Grand River system in 2011.

Cash flows used for investing activities increased by $514.0 million, or 334%, to $667.7 million in 2011 from $153.7 million in 2010. The increase in cash flows used for investing activities was primarily due to the acquisition of the Grand River system for $589.5 million. Capital expenditures decreased by $75.5 million, or 49%, to $78.2 million in

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2011 from $153.7 million in 2010. Capital expenditures in 2010 were higher due to the installation and commissioning of compressor stations on the DFW Midstream system.

Cash flows from financing activities increased by $519.7 million, or 455%, to $633.8 million in 2011 from $114.1 million in 2010. The increase in cash flows from financing activities was primarily due to the acquisition of the Grand River system. The Predecessor received equity contributions of $410.0 million and a $200.0 million non-recourse loan from the Sponsors to acquire the Grand River system. The Predecessor closed on the revolving credit facility in May 2011. Upon closing the revolving credit facility, the Predecessor made a $132.9 million distribution to Energy Capital Partners from the $142.0 million drawn at closing.

Contractual Obligations

The table below summarizes our contractual obligations and other commitments as of December 31, 2012:

	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
	(In thousands)				
Long-term debt and interest payments (1)	$225,508	$7,691	$15,382	$202,435	$—
Operating leases (2)	3,155	859	1,449	847	—
Total contractual obligations	$228,663	$8,550	$16,831	$203,282	$—

(1) Includes a 0.50% commitment fee on the unused portion of the revolving credit facility. See Note 6 to the audited consolidated financial statements for additional information.

(2) See Note 11 to the audited consolidated financial statements for additional information.

Off-Balance Sheet Arrangements

We had no off-balance sheet arrangements as of or during the year ended December 31, 2012.

Capital Requirements

The natural gas gathering segment of the midstream energy business is capital-intensive, requiring significant investment for the maintenance of existing gathering systems and the acquisition or construction and development of new gathering systems and other midstream assets and facilities. Our partnership agreement requires that we categorize our capital expenditures as either:

- maintenance capital expenditures, which are cash expenditures (including expenditures for the addition or improvement to, or the replacement of, our capital assets or for the acquisition of existing, or the construction or development of new, capital assets) made to maintain our long-term operating income or operating capacity; or
- expansion capital expenditures, which are cash expenditures incurred for acquisitions or capital improvements that we expect will increase our operating income or operating capacity over the long term.

Total capital expenditures were as follows:

	Year ended December 31,		
	2012	2011	2010
	(In thousands)		
Capital expenditures	$76,698	$78,248	$153,719

In 2012, total capital expenditures were largely the result of the construction of new pipeline and compression infrastructure to connect new pad sites on our DFW Midstream system and to install meters and build out medium-pressure infrastructure on our Grand River system. In 2011, total capital expenditures were primarily associated with the construction of new pipeline infrastructure to connect new pad sites on our DFW Midstream system. In 2010, total capital expenditures were largely attributable to the installation and commissioning of compressor stations on the DFW Midstream system.

In the fourth quarter of 2012, we began tracking maintenance capital expenditures for the purposes of calculating distributable cash flow. Prior to the fourth quarter of 2012, we did not distinguish between maintenance and expansion capital expenditures. Therefore, to calculate distributable cash flow, we have estimated the portion of these expenditures that were maintenance capital expenditures for periods prior to the fourth quarter of 2012.

We anticipate that we will continue to make significant expansion capital expenditures in the future. Consequently, our ability to develop and maintain sources of funds to meet our capital requirements is critical to our ability to meet our growth objectives. We expect that our future expansion capital expenditures will be funded by borrowings under the revolving credit facility and the issuance of debt and equity securities.

Distributions

Based on the terms of SMLP's partnership agreement, SMLP expects that it will distribute to its unitholders most of the cash generated by its operations. As a result, SMLP expects to fund future capital expenditures from cash and cash equivalents on hand, non-distributed cash flow generated from its operations, borrowings under the revolving credit facility and future issuances of equity and debt securities. Historically, the Predecessor largely relied on internally generated cash flows and capital contributions from Energy Capital Partners and GE Energy Financial Services to satisfy its capital expenditure requirements.

There were no cash distributions paid by SMLP prior to 2013 other than the distribution of proceeds from the IPO. On January 23, 2013, the board of directors of our general partner declared a distribution of $0.41 per unit for the quarterly period ended December 31, 2012. The distribution, which totaled approximately $20.4 million, was paid on February 14, 2013 to unitholders of record at the close of business on February 7, 2013.

Revolving Credit Facility

Effective May 7, 2012, Summit Holdings amended and restated its revolving credit facility with a syndicate of lenders to increase its borrowing capacity from $285.0 million to $550.0 million. Substantially all of SMLP's assets are pledged as collateral under the revolving credit facility. It matures in May 2016 and, at our option, borrowings thereunder bear interest at a variable rate per annum equal to either (i) the London InterBank Offered Rate plus the applicable margins ranging from 2.5% to 3.5% or (ii) a base rate plus the applicable margins ranging from 1.5% to 2.5%.

The revolving credit facility contains affirmative and negative covenants customary for credit facilities of its size and nature, that, among other things, limit or restrict our ability (as well as the ability of our subsidiaries) to:

- permit the ratio of our trailing 12-month EBITDA to our consolidated cash interest charges as of the end of any fiscal quarter to be less than 2.50 to 1.00;
- permit the ratio of our consolidated net debt to trailing 12-month EBITDA on the last day of any quarter to be above 5.00 to 1.00 (or 5.50 to 1.00 if we have made certain business acquisitions);
- incur any additional debt, subject to customary exceptions for certain permitted additional debt, or incur liens on assets, subject to customary exceptions for permitted liens;
- make any investments, subject to customary exceptions for certain permitted investments;
- engage in certain mergers, consolidations, sales of assets or acquisitions, subject to customary exceptions for permitted transactions of such types;
- pay dividends or make cash distributions, provided that we may make quarterly distributions to our unitholders, so long as no default or event of default under the amended and restated credit agreement then exists or would result therefrom, and subject to compliance (on both a pro forma basis and after giving effect to the making of such distribution) with our financial performance covenants under the amended and restated credit agreement;
- enter into any swap agreements or power purchase agreements, subject to customary exceptions, such as the entry into swap agreements and power purchase agreements in the ordinary course of business; and
- enter into leases that would cumulatively obligate payments in excess of $30.0 million over any 12-month period.

As of December 31, 2012, we were in compliance with the financial and other covenants in our revolving credit facility.

The revolving credit facility also contains events of default customary for credit facilities of its size and nature, including, but not limited to:

- events of default resulting from our failure to comply with covenants;

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- the occurrence of a change of control of our general partner;
- the institution of insolvency or similar proceedings against us;
- the occurrence of a default under any other material indebtedness we may have; and
- the termination of any one or more or our gas gathering agreements accounting for 25% or more of our revenue that results in a material adverse effect (as defined in the amended and restated credit agreement) and for which a replacement gas gathering agreement with substantially similar terms is not entered into within 30 days after such termination.

Upon the occurrence of an event of default, subject to the terms and conditions of the revolving credit facility, the lenders may, in addition to exercising other remedies, declare any outstanding principal and any accrued and unpaid interest to be immediately due and payable. There were no defaults during 2012.

We expect to use future borrowings under the revolving credit facility for working capital and other general partnership purposes and capital expenditures. For additional information, see Note 6 to the audited consolidated financial statements.

Promissory Notes Payable to Sponsors

In connection with our acquisition of the Grand River system in 2011, the Predecessor executed promissory notes, on an unsecured basis, with our Sponsors. The notes totaled $200.0 million, had an 8% interest rate and a maturity date of October 2013. In July 2012, the Predecessor repaid the promissory notes in full. For additional information, see Note 12 to the audited consolidated financial statements.

Credit Risk and Customer Concentration

We examine the creditworthiness of third-party customers to whom we extend credit and manage our exposure to credit risk through credit analysis, credit approval, credit limits and monitoring procedures, and for certain transactions, we may request letters of credit, prepayments or guarantees. A significant percentage of our revenue is attributable to three producer customers and one natural gas marketer. For additional information, see Note 13 to the audited consolidated financial statements.

Critical Accounting Policies and Estimates

We prepare our financial statements in accordance with GAAP. These principles are established primarily by the Financial Accounting Standards Board. We employ methods, estimates and assumptions based on currently available information when recording transactions resulting from business operations. Our significant accounting policies are described in Note 2 to the audited consolidated financial statements.

The estimates that we deem to be most critical to an understanding of our financial position and results of operations are those related to determination of fair value and recognition of deferred revenues. The preparation and evaluation of these critical accounting estimates involve the use of various assumptions developed from management's analyses and judgments. Subsequent experience or use of other methods, estimates or assumptions could produce significantly different results. Our critical accounting estimates are as follows:

Recognition and Impairment of Long-Lived Assets

Our long-lived assets include property, plant and equipment, our contract intangible assets and goodwill.

Property, Plant and Equipment and Intangible Assets. As of December 31, 2012, we had net property, plant and equipment with a carrying value of approximately $682.0 million and net intangible assets with a carrying value of approximately $285.5 million.

When evidence exists that we will not be able to recover a long-lived asset's carrying value through future cash flows, we write down the carrying value of the asset to its estimated fair value. We test assets for impairment when events or circumstances indicate that the carrying value of a long-lived asset may not be recoverable. With respect to property, plant and equipment and our contract intangible assets, the carrying value of a long-lived asset is not recoverable if the carrying value exceeds the sum of the undiscounted cash flows expected to result from the asset's use and eventual disposal. In this situation, we recognize an impairment loss equal to the amount by which the carrying value exceeds the asset's fair value. We determine fair value using an income approach in which we discount the asset's expected future cash flows to reflect the risk associated with achieving the underlying cash

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flows. During the three-year period ended December 31, 2012, we concluded that none of our long-lived assets had been impaired.

For additional information, see Notes 2, 4 and 5 to the audited consolidated financial statements.

Goodwill. Goodwill represents consideration paid in excess of the fair value of the identifiable assets acquired in a business combination. As of December 31, 2012, we had goodwill of $45.5 million that we recognized in connection with the acquisition of the Grand River system in October 2011. In the second quarter of 2012, we received the remaining information needed to determine the value associated with certain acquired assets. We then finalized the purchase price allocation and recognized the assets acquired and liabilities assumed on a retrospective basis. Management believes that the goodwill recorded upon the finalization of the allocation represents the incremental value of future cash flow potential attributed to estimated future gathering services within the emerging Mancos and Niobrara shale developments.

We evaluate goodwill for impairment annually on September 30. We also evaluate goodwill whenever events or circumstances indicate that it is more likely than not that the fair value of a reporting unit is less than its carrying amount.

We test goodwill for impairment using a two-step quantitative test. In step one, we compare the fair value of the reporting unit to its carrying value, including goodwill. If the reporting unit's fair value exceeds its carrying amount, we conclude that the goodwill of the reporting unit has not been impaired and no further work is performed. If we determine that the reporting unit's carrying value exceeds its fair value, we proceed to step two. In step two, we compare the carrying value of the reporting unit to its implied fair value. If we determine that the carrying amount of a reporting unit's goodwill exceeds its implied fair value, we recognize the excess of the carrying value over the reporting unit's implied value as an impairment loss.

We performed our annual goodwill impairment analysis as of September 30, 2012 and determined that no factors existed which would lead us to conclude that an impairment of goodwill was necessary. No events or circumstances have occurred since the Grand River system acquisition in October 2011 that would require an interim impairment test. Presently, we do not believe that the Grand River system reporting unit is at risk of failing step one. Prior to the acquisition of the Grand River system, the Predecessor had no goodwill.

For additional information, see Notes 2, 3 and 5 to the audited consolidated financial statements.

Minimum Volume Commitments

The majority of our gas gathering agreements provide for a monthly or annual MVC from our customers. As of December 31, 2012, we had MVCs totaling 2.4 Tcf through 2026.

Under these monthly or annual MVCs, our customers agree to ship a minimum volume of natural gas on our gathering systems or to pay a minimum monetary amount over certain periods during the term of the MVC. A customer must make a shortfall payment to us at the end of the contract month or year, as applicable, if its actual throughput volumes are less than its MVC for that month or year. Certain customers are entitled to utilize shortfall payments to offset gathering fees in one or more subsequent periods to the extent that such customer's throughput volumes in subsequent periods exceed its MVC for that period. These contract provisions range from one month to nine years.

We recognize customer billings for obligations under their MVCs as deferred revenue when the customer has the right to utilize shortfall payments to offset gathering fees in subsequent periods. As of December 31, 2012, we had current deferred revenue totaling approximately $0.9 million and noncurrent deferred revenue totaling approximately $10.9 million. We classify deferred revenue as a current liability for arrangements where the expiration of a customer's right to utilize shortfall payments is 12 months or less. We classify deferred revenue as noncurrent for arrangements where the expiration of the right to utilize shortfall payments and our estimate of its potential utilization is more than 12 months.

We recognize revenue when all of the following criteria are met: (i) persuasive evidence of an exchange arrangement exists, (ii) delivery has occurred or services have been rendered, (iii) the price is fixed or determinable, and (iv) collectability is reasonably assured. With respect to MVCs, we reclassify deferred revenue to gathering services and other fees revenue under these arrangements once all potential performance obligations associated with the related MVC have either (i) been satisfied through the gathering of future excess volumes, or (ii) expired (or lapsed) through the passage of time pursuant to the terms of the natural gas gathering agreement.

For additional information, see Note 2 to the audited consolidated financial statements.

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Compensatory Awards

Certain of our current and former employees were granted Class B membership interests, classified as net profits interests, in DFW Midstream or Summit Midstream Management, LLC. We refer to these interests collectively as the net profits interests. The net profits interests participate in distributions upon time vesting and the achievement of certain distribution targets to Class A members or higher priority vested net profits interests. The net profits interests are accounted for as compensatory awards. The net profits interests vest ratably over four to five years (as defined in the underlying award agreement), and provide for accelerated vesting in certain limited circumstances, including a qualifying termination following a change in control (as defined in the underlying award agreement and the Summit Midstream Partners LLC Agreement and the DFW Midstream Amended and Restated Limited Liability Company Agreement and Contribution Agreement). With the assistance of a third-party valuation firm, we determined the fair value of the net profits interests as of the respective grant dates. The net profits interests were valued utilizing an option pricing method, which models the Class A and Class B membership interests as call options on the underlying enterprise equity value and considers the rights and preferences of each class of equity to allocate a fair value to each class. We used a combination of the income and market approaches, including the following assumptions and internal and external factors in determining the grant date fair value of the net profits interests: (i) assumptions underlying the enterprise value used in connection with the option pricing method, including the discount rate applied to estimated future cash flows, forecasted gathering volumes, revenues and costs, equity performance relative to peer group members, equity market risk premium, enterprise-specific risk premium, and terminal growth rates; (ii) holding period restrictions; (iii) discounts for lack of marketability; and (iv) expected volatility rates based on the historical and implied volatility of other midstream services companies whose share or option prices are publicly available.

For additional information, see Note 9 to the audited consolidated financial statements.

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

Interest Rate Risk

We have exposure to changes in interest rates on our indebtedness associated with the revolving credit facility. The credit markets have recently experienced historical lows in interest rates. As the overall economy strengthens, it is possible that monetary policy will tighten further, resulting in higher interest rates to counter possible inflation. Interest rates on floating rate credit facilities and future debt offerings could be higher than current levels, causing our financing costs to increase accordingly.

A hypothetical 1.0% increase (decrease) in interest rates would have increased (decreased) our interest expense by approximately $2.4 million for the year ended December 31, 2012.

Commodity Price Risk

Because we currently generate a substantial majority of our revenues pursuant to long-term, fee-based gas gathering agreements that include MVCs and AMIs, our only direct commodity price exposure relates to (i) our sale of physical natural gas we retain from our DFW Midstream customers, (ii) our procurement of electricity to operate our electric-drive compression assets on the DFW Midstream system and (iii) the sale of condensate volumes that we collect on the Grand River system. Our gas gathering agreements with our Barnett Shale customers permit us to retain a certain quantity of natural gas that we sell to offset the power costs we incur to operate our electric-drive compression assets. Our gas gathering agreements with our Grand River customers permit us to retain condensate volumes from the Grand River system gathering lines. We manage our direct exposure to natural gas and power prices through the use of forward power purchase contracts with wholesale power providers that require us to purchase a fixed quantity of power at a fixed heat rate based on prevailing natural gas prices on the Waha Hub Index. Because we also sell our retainage gas at prices that are based on the Waha Hub Index, we have effectively fixed the relationship between our compression electricity expense and natural gas sales. We do not enter into risk management contracts for speculative purposes.

Item 8. Financial Statements and Supplementary Data.

The audited consolidated financial statements required to be included in this Annual Report on Form 10-K appear immediately following the signature page to this Form 10-K, beginning on page F-1.

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Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure Matters.
There have been no changes in, or disagreements with, accountants on accounting and financial disclosure matters during the years ended December 31, 2012 and 2011.

Item 9A. Controls and Procedures.
Disclosure Controls and Procedures
SMLP’s management, with the participation of the Chief Executive Officer and Chief Financial Officer of SMLP's general partner, has evaluated the effectiveness of SMLP’s disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) as of the end of the period covered by this annual report (the "Evaluation Date"). Based on such evaluation, the Chief Executive Officer and Chief Financial Officer of SMLP's general partner have concluded that, as of the Evaluation Date, SMLP’s disclosure controls and procedures are effective.
Changes in Internal Control Over Financial Reporting
There have not been any changes in SMLP’s internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the fourth fiscal quarter of 2012 that have materially affected, or are reasonably likely to materially affect, SMLP's internal control over financial reporting.
Management's Report on Internal Control Over Financial Reporting
This annual report does not include a report of management's assessment regarding internal control over financial reporting or an attestation report of SMLP's independent registered public accounting firm due to a transition period established by rules of the SEC for newly public companies.

Item 9B. Other Information.
On March 15, 2013, our Board granted 146,231 phantom units with distribution equivalent rights to certain key employees that provide services to us, including executive officers, pursuant to the 2012 Long-Term Incentive Plan (the "LTIP"). Of the employee units, 34,629, 15,391 and 14,429 phantom units were granted to Messrs. Newby, Harrison and Degeyter, respectively. The phantom units granted to the named executive officers in March of 2013 vest ratably over a three-year period, subject to accelerated vesting on the occurrence of any of the following events: (i) a termination of the officer's employment other than for cause, (ii) a termination of the officer's employment by the officer for good reason (as defined in the officer's employment agreement), (iii) a termination of the officer's employment by reason of the officer's death or disability or (iv) a Change in Control (as defined in the applicable award agreement). Messrs. Newby, Harrison and Degeyter received distribution equivalent rights for each phantom unit, providing for a lump sum cash amount equal to the accrued distributions from the grant date of the phantom units to be paid in cash upon the vesting of such units. A form of the award agreement pursuant to which these phantom units were granted is filed as exhibit 10.15 to this Annual Report on Form 10-K.

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PART III

Item 10. Directors, Executive Officers and Corporate Governance.

Management of Summit Midstream Partners, LP

We are managed by the directors and executive officers of our general partner, Summit Midstream GP, LLC. Our general partner is not elected by our unitholders and will not be subject to re-election in the future. Summit Investments, which is owned and controlled by Energy Capital Partners and GE Energy Financial Services, is the sole owner of our general partner and has the right to appoint the entire board of directors of our general partner, including our independent directors. All decisions of the board of directors of our general partner will require the affirmative vote of a majority of all of the directors constituting the board, provided that such majority includes at least a majority of the directors designated as an "Energy Capital Partner Designated Director" by Energy Capital Partners. The Energy Capital Partner Designated Directors are Thomas K. Lane, Andrew F. Makk, Curtis A. Morgan and Jeffery R. Spinner. Our unitholders are not entitled to directly or indirectly participate in our management or operations. Our general partner is liable, as general partner, for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made specifically nonrecourse to it. Whenever possible, we intend to incur indebtedness that is nonrecourse to our general partner.

Our general partner's limited liability company agreement provides that the board of directors of our general partner must obtain the approval of members representing a majority interest in our general partner for certain actions affecting us. These include actions related to:

- transactions with affiliates;
- entering into any hedging transactions that are not in compliance with Financial Accounting Standard 133;
- the voluntary liquidation, wind-up or dissolution of us or any of our subsidiaries;
- making any election that would result in us being classified as other than a partnership or a disregarded entity for U.S. federal income tax purposes;
- filing or consenting to the filing of any bankruptcy, insolvency or reorganization petition for relief from debtors or protection from creditors naming us or any of our subsidiaries; and
- effecting a material amendment to our general partner's limited liability company agreement.

Currently, Summit Investments is the sole member of our general partner. As long as Summit Investments is a member of our general partner, any approval of an action described in the above list must be evidenced by a resolution adopted by the board of managers of Summit Investments.

In connection with our initial public offering, Summit Investments and our general partner entered into an investor rights agreement with an affiliate of GE Energy Financial Services. The investor rights agreement provided that GE Energy Financial Services or its affiliates could elect to designate one director or one non-voting observer to the board of directors of our general partner for as long as the affiliate of GE Energy Financial Services held at least a 10% limited liability company interest in Summit Investments. In October 2012, the investor rights agreement terminated because the affiliate of GE Energy Financial Services' limited liability company interest in Summit Investments was less than 10%. As a result, the affiliate of GE Energy Financial Services no longer has a right to appoint a director or a non-voting observer to our general partner's board of directors.

Committees of the Board of Directors

The board of directors of our general partner has an audit committee (the "Audit Committee") and a conflicts committee (the "Conflicts Committee") and may have such other committees as the board of directors shall determine from time to time.

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The table below shows the current membership of each standing board committee.

Name	Audit Committee	Conflicts Committee	Independent Director
Thomas K. Lane			No
Andrew F. Makk	Member		No
Curtis A. Morgan			No
Steven J. Newby			No
Jerry L. Peters	Chair	Member	Yes
Jeffery R. Spinner			No
Susan Tomasky	Member	Chair	Yes

Each of the standing committees of the board of directors will have the composition and responsibilities described below.

Audit Committee. Jerry L. Peters, Andrew F. Makk and Susan Tomasky serve as the members of the Audit Committee. Mr. Peters serves as the chair of our Audit Committee. In this role, Mr. Peters satisfies the SEC and New York Stock Exchange rules regarding independence and qualifies as an audit committee financial expert.

We are relying on the phase-in rules of the SEC and the New York Stock Exchange with respect to the independence of the Audit Committee. Those rules permit our general partner to have an audit committee that has one independent member upon the effectiveness of our registration statement, a majority of independent members within 90 days thereafter and all independent members within one year thereafter. Our general partner is generally required to have at least three independent directors serving on its board at all times within one year after the effectiveness of our registration statement. In November 2012, Susan Tomasky was appointed to the board of directors of our general partner and to the Audit Committee. Prior to Ms. Tomasky's appointment, Mr. Thomas K. Lane served on the Audit Committee of our general partner. In compliance with the board transition rules, Mr. Makk will resign from the Audit Committee when the final independent director is appointed.

The Audit Committee assists the board of directors in its oversight of the integrity of our financial statements and our compliance with legal and regulatory requirements and corporate policies and controls. The Audit Committee has the sole authority to retain and terminate our independent registered public accounting firm, approve all auditing services and related fees and the terms thereof, and pre-approve any non-audit services to be rendered by our independent registered public accounting firm. The Audit Committee is also responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm has unrestricted access to the Audit Committee.

Our audit committee has adopted an audit committee charter, which is available on our website at www.summitmidstream.com.

Conflicts Committee. At the direction of our general partner, our Conflicts Committee will review specific matters that may involve conflicts of interest in accordance with the terms of our partnership agreement. The Conflicts Committee will determine if the resolution of the conflict of interest is in the best interests of our partnership. There is no requirement that our general partner seek the approval of the Conflicts Committee for the resolution of any conflict. The members of the Conflicts Committee may not be officers or employees of our general partner or directors, officers, employees of any of its affiliates. They may not hold any ownership interest in our general partner or us and our subsidiaries other than common units and other awards that are granted under our incentive plans in place from time to time. Furthermore, the members of the Conflicts Committee must meet the independence and experience standards established by the New York Stock Exchange and the Exchange Act to serve on an audit committee of a board of directors. Our Conflicts Committee will consist of one or more directors meeting these requirements. Mr. Peters and Ms. Tomasky serve as the members of our Conflicts Committee with Ms. Tomasky as chair of the committee. We anticipate that once appointed to our general partner's board of directors, the additional independent member(s) appointed to the Audit Committee will also serve on the Conflicts Committee.

Any matters approved by the Conflicts Committee in good faith will be conclusively deemed to be approved by all of our partners and not a breach by our general partner of any duties it may owe us or our unitholders. Any unitholder challenging any matter approved by the Conflicts Committee will have the burden of proving that the members of the Conflicts Committee did not subjectively believe that the matter was in the best interests of our partnership. Moreover, any acts taken or omitted to be taken in reliance upon the advice or opinions of experts such as legal

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counsel, accountants, appraisers, management consultants and investment bankers, where our general partner (or any members of the board of directors of our general partner including any member of the Conflicts Committee) reasonably believes the advice or opinion to be within such person's professional or expert competence, shall be conclusively presumed to have been taken or omitted in good faith.

Directors and Executive Officers

Directors are appointed for a term of one year and hold office until their successors have been elected or qualified or until the earlier of their death, resignation, removal or disqualification. Officers serve at the discretion of the board of directors of our general partner. The following table shows information for the directors and executive officers of our general partner as of February 28, 2013.

Name	Age	Position with Summit Midstream GP, LLC
Steven J. Newby	40	President, Chief Executive Officer and Director
Matthew S. Harrison	42	Senior Vice President and Chief Financial Officer
Rene L. Casadaban	44	Senior Vice President, Engineering, Construction and Operations, Southwest Region
Brock M. Degeyter	36	Senior Vice President and General Counsel
Brad N. Graves	46	Senior Vice President, Corporate Development
Jesse G. Wood	57	Senior Vice President, Engineering, Construction and Operations, Rockies Region
Thomas K. Lane	56	Director
Andrew F. Makk	43	Director
Curtis A. Morgan	52	Director
Jerry L. Peters	55	Director
Jeffery R. Spinner	31	Director
Susan Tomasky	59	Director

Steven J. Newby has been the President and Chief Executive Officer of our general partner since May 2012. Mr. Newby was a founding member of Summit Midstream Partners, LLC and has been the President and Chief Executive Officer of Summit Midstream Partners, LLC since its formation in September 2009. Mr. Newby's background includes over 17 years of oil and gas experience with a focus on the midstream sector of the energy industry. Mr. Newby was a founding member of SunTrust Bank's Corporate Energy industry specialty group and ultimately became a Managing Director and Head of the Project Finance Group within SunTrust's Capital Markets division. In 2007, Mr. Newby joined ING Investment Management to manage a $300 million proprietary fund focused on the private and public investment in the energy infrastructure space. Mr. Newby is a graduate of the University of North Carolina at Chapel Hill with a B.S. in Business Administration with a concentration in Finance.

Matthew S. Harrison has been the Senior Vice President and Chief Financial Officer of our general partner since May 2012. Prior to joining our general partner, Mr. Harrison was the Senior Vice President and Chief Financial Officer of Summit Midstream Partners, LLC since September 2011. Mr. Harrison's background includes over 14 years of energy and finance experience. Mr. Harrison joined Summit Midstream Partners, LLC from Hiland Partners, LP, where he served as Executive Vice President and Chief Financial Officer, Secretary and Director from February 2008 to September 2011. Prior to joining Hiland, Mr. Harrison was a Director in the Energy & Power Merger & Acquisitions group at Wachovia Capital Markets from October 2007 to February 2008 and a Director in the Mergers & Acquisitions group at A.G. Edwards & Sons, Inc. from July 1999 to October 2007. Mr. Harrison was a Senior Accountant for Price Waterhouse for five years. Mr. Harrison received an MBA from Northwestern University—Kellogg Graduate School of Management in 1999 and a B.S. in Accounting from the University of Tennessee in 1992.

Rene L. Casadaban has been the Senior Vice President of Engineering, Construction, and Operations of our general partner since May 2012. Prior to joining our general partner, Mr. Casadaban was the Senior Vice President of Engineering, Construction and Operations of Summit Midstream Partners, LLC from February 2011 until April 2012, and prior to that he served as a vice president from the time he joined Summit Midstream Partners, LLC in November 2010. Mr. Casadaban has 20 years of project management experience for onshore, offshore and deepwater pipeline systems. Prior to joining Summit Midstream Partners, LLC, Mr. Casadaban worked for Enterprise Products Partners L.P. from 2006 to 2010 as the Director for Deepwater Development of floating production platforms and offshore pipelines. Mr. Casadaban has also served as an independent consultant to ExxonMobil and GulfTerra for Gulf of Mexico and international pipeline projects. At Land & Marine, Mr. Casadaban was responsible for managing domestic and international pipeline river crossings and beach approaches by horizontal directional drilling. Mr. Casadaban is a graduate of Auburn University with a B.S. in Building Construction.

Brock M. Degeyter has been the Senior Vice President and General Counsel of our general partner since May 2012. Mr. Degeyter joined Summit Midstream Partners, LLC in January 2012 as Senior Vice President and General Counsel. Mr. Degeyter's background includes over ten years of energy, finance and business law experience. Prior to joining our general partner, Mr. Degeyter worked in the corporate legal department for Energy Future Holdings (formerly TXU Corp.) from January 2007 through December 2011 where he served as Director of Corporate Governance and Senior Counsel. Prior to joining Energy Future Holdings, Mr. Degeyter was engaged in private practice with the firm of Correro Fishman Haygood Phelps Walmsley & Casteix LLP from May 2002 through December 2006. Mr. Degeyter is licensed to practice law in the states of Texas and Louisiana. Mr. Degeyter received a B.A. in Political Science from Louisiana State University and a J.D. from Loyola University College of Law in New Orleans.

Brad N. Graves has been the Senior Vice President of Corporate Development of our general partner since May 2012. In March 2013, he was promoted to Chief Commercial Officer. Prior to joining our general partner, Mr. Graves was the Senior Vice President of Corporate Development of Summit Midstream Partners, LLC since April 2010. He was previously a Partner with Crestwood Midstream Partners, LLC from February 2008 until March 2010. Mr. Graves has served as Executive Vice President—Business Development of Genesis Energy, LP (AMEX: GEL) from August 2006 until November 2007. He also served as Vice President—Offshore Commercial for Enterprise Products Partners L.P. (NYSE: EPD) from 2004 until August 2006. Prior to 2004, Mr. Graves served in a variety of commercial roles at EPD and GulfTerra Energy Partners, LP (NYSE: GTM), prior to its merger with EPD. In his roles with EPD and GTM, Mr. Graves participated in numerous greenfield projects developed in the Gulf of Mexico. Mr. Graves earned a B.B.A. in Accounting from Texas A&M University in 1989 and an MBA in Marketing and Finance from the University of Saint Thomas in 1994.

Jesse G. Wood began serving as Senior Vice President of Engineering, Construction, and Operations of our general partner in January 2013, and prior to that he served as Vice President and Region Manager for the Rockies Region from the time that he joined Summit Midstream Partners, LLC in April 2012 until January 2013. Mr. Wood has over 32 years of experience working in the Rocky Mountain region developing, building, and operating midstream facilities. Prior to joining Summit Midstream Partners, LLC, Mr. Wood worked for nine years as the South Rockies Midstream Team Leader for Encana, executing and operating midstream projects in the DJ, Paradox, and Piceance basins, where his teams developed midstream assets to support a 1.2 Bcf/d gathering system. Prior to that, Mr. Wood served for 20 years with Union Pacific Resources Company in a variety of engineering and leadership roles developing Rocky Mountain midstream facilities. Prior to 1983, Mr. Wood was employed by Duke Energy Field Services, where he served for four years as General Manager of the company's Rocky Mountain operations. Mr. Wood is a graduate of New Mexico State University, where he earned a bachelor's degree in Chemical Engineering.

Thomas K. Lane has served as a director of our general partner since May 2012 and was appointed to the board in connection with his affiliation with Energy Capital Partners, which controls our general partner. Mr. Lane has been a partner of Energy Capital Partners since 2005. Prior to joining Energy Capital Partners, Mr. Lane worked for 17 years in the Investment Banking Division at Goldman Sachs. As a Managing Director at Goldman Sachs, Mr. Lane had senior-level coverage responsibility for electric and gas utilities, independent power companies and merchant energy companies throughout the United States. Mr. Lane received a B.A. in economics from Wheaton College and an MBA from the University of Chicago. Mr. Lane was selected to serve as a director on the board due to his affiliation with Energy Capital Partners, his knowledge of the energy industry and his financial and business expertise.

Andrew F. Makk has served as a director of our general partner since May 2012 and was appointed to the board in connection with his affiliation with Energy Capital Partners, which controls our general partner. Mr. Makk has been a Principal at Energy Capital Partners since 2005. Prior to joining Energy Capital Partners, he was a co-founder of a privately held energy company from 2002 to 2005, which built a portfolio of energy projects in Europe on behalf of a private equity fund. Prior to 2002, Mr. Makk spent nine years with Enron International in various power and LNG asset development roles and became Head of Asset Development for Enron Europe in London. He received a B.S.M. in Finance from Tulane University and an MBA from the Fuqua School of Business at Duke University. Mr. Makk was selected to serve as a director on the board due to his affiliation with Energy Capital Partners, his knowledge of the energy industry and his financial and business expertise.

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Curtis A. Morgan has served as a director of our general partner since May 2012 and was appointed to the board in connection with his affiliation with Energy Capital Partners, which controls our general partner. Mr. Morgan has served as the President and Chief Executive Officer of EquiPower Resources Corp. since May 2010. Prior to joining EquiPower Resources Corp., he served as an Operating Partner of Energy Capital Partners from May 2009 to May 2010. Prior to joining Energy Capital Partners, he served as President and Chief Executive Officer of FirstLight Power Enterprises from November 2006 to April 2009. Mr. Morgan has also held leadership positions at NRG Energy, Mirant Corporation and Reliant Energy. Mr. Morgan received a B.A. in Accounting from Western Illinois University and an MBA in Finance and Economics from the University of Chicago. He is a Certified Public Accountant. We believe that Mr. Morgan's extensive executive, financial and operational experience bring important and necessary skills to the board of directors.

Jerry L. Peters has served as a director of our general partner since September 2012. Additionally, Mr. Peters served as the chair of the Conflicts Committee of our general partner until Ms. Tomasky's appointment to the role in November 2012 and serves as the chair and financial expert of the Audit Committee of our general partner. Mr. Peters has served as the Chief Financial Officer of Green Plains Renewable Energy, Inc., a publicly-traded vertically-integrated ethanol producer, since May 2007. Prior to that, Mr. Peters served as Senior Vice President—Chief Accounting Officer for ONEOK Partners, L.P. from May 2006 to April 2007, as Chief Financial Officer of ONEOK Partners, L.P. from July 1994 to May 2006, and in various senior management roles of ONEOK Partners, L.P. from 1985 to May 2006. Prior to joining ONEOK Partners, Mr. Peters was employed by KPMG LLP as a certified public accountant from 1980 to 1985. Mr. Peters received an MBA from Creighton University with an emphasis in finance and a B.S. in Business Administration from the University of Nebraska—Lincoln. We believe that Mr. Peters' extensive executive, financial and operational experience bring important and necessary skills to the board of directors.

Jeffrey R. Spinner has served as a director of our general partner since November 2012 and was appointed to the board in connection with his affiliation with Energy Capital Partners, which controls our general partner. Mr. Spinner has been an investment professional at Energy Capital Partners since 2006. Prior to joining Energy Capital Partners, Mr. Spinner worked in the Natural Resources Investment Banking Group at Banc of America Securities. Mr. Spinner received a B.S. in Economics from Duke University.

Susan Tomasky has served as a director of our general partner since November 2012. Additionally, Ms. Tomasky serves as the chair of the Conflicts Committee of our general partner. Ms. Tomasky was a senior executive for 13 years at American Electric Power, one of the nation’s largest electric utilities, serving from 2009 to 2011 as President of the company’s transmission business, from 2007 through 2008 as Executive Vice President for Shared Services, from 2001 until 2007 as Executive Vice President and Chief Financial Officer, and from 1998 until 2001 as General Counsel. Ms. Tomasky currently serves as a director of two other public companies—Tesoro Corp. and Public Service Enterprise Group. Ms. Tomasky holds a juris doctorate degree from George Washington University National Law Center, and received her undergraduate degree from University of Kentucky in Lexington. Ms. Tomasky's extensive executive, financial, legal and regulatory experience bring important and necessary skills to the board of directors.

Code of Ethics

The board of directors of our general partner has adopted a Code of Business Conduct and Ethics which sets forth SMLP’s policy with respect to business ethics and conflicts of interest. The Code of Business Conduct and Ethics is intended to ensure that the employees, officers and directors of SMLP conduct business with the highest standards of integrity and in compliance with all applicable laws and regulations. It applies to the employees, officers and directors of SMLP, including its principal executive officer, principal financial officer and principal accounting officer or controller, or persons performing similar functions (the "Senior Financial Officers"). The Code of Business Conduct and Ethics also incorporates expectations of the Senior Financial Officers that enable us to provide accurate and timely disclosure in our filings with the SEC and other public communications. The Code of Business Conduct and Ethics is publicly available on our website under the "Corporate Governance" subsection of the Investors section at www.summitmidstream.com and is also available free of charge on request to the Secretary at the Dallas office address given under the "Contact" section on our website.

Section 16(a) Beneficial Owner Reporting Compliance

Section 16(a) of the Exchange Act requires SMLP's directors and executive officers, and persons who own more than 10% of a registered class of our securities, to file with the SEC initial reports of ownership and reports of changes in ownership of SMLP's common units and other equity securities. Based on our records, we believe that all directors, executive officers and persons who own more than 10% of our common units have complied with the reporting requirements of Section 16(a), except that, due to an administrative oversight, the Form 3 required in

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connection with Susan Tomasky's addition to the board of directors of our general partner was not timely filed. On December 5, 2012, a Form 3 was filed to report that she did not own any Company securities on November 9, 2012, which is the date that she was appointed as a director of our general partner.

Item 11. Executive Compensation.

Executive Compensation

The following describes the material components of our executive compensation program for the following individuals, who are referred to as the "named executive officers":

- Steven J. Newby, President and Chief Executive Officer;
- Matthew S. Harrison, Senior Vice President and Chief Financial Officer; and
- Brock M. Degeyter, Senior Vice President and General Counsel.

The named executive officers are employees of Summit Investments and executive officers of our general partner. The named executive officers devote a majority of their working time to SMLP's business; however, they also maintain responsibilities for Summit Investments and its affiliates other than us. Under the terms of our partnership agreement, our general partner determines the portion of the named executive officers' compensation that is allocated to us. For additional information, please refer to the discussion under the heading “General and Administrative Expense Allocation” in Item 13. Certain Relationships and Related Transactions, and Director Independence.

Summary Compensation Table for 2012 and 2011. The following table sets forth certain information with respect to the compensation paid to our named executive officers for the years ended December 31, 2012 and 2011. For 2012, the amounts shown in the summary compensation table below generally reflect 100% of the compensation paid to the named executive officers by the Predecessor prior to our IPO and the portion of the compensation paid to the named executive officers and allocated to SMLP for the period following our IPO. For 2011, our general partner did not perform any such allocation of compensation costs, and the amounts shown in the summary compensation table below for 2011 reflect 100% of the compensation paid by the Predecessor to our named executive officers.

Name and Principal Position	Year	Salary ($) (1)	Bonus ($)(2)	Non-Equity Incentive Plan Compen-sation ($)(3)	Unit awards ($)(4)	All Other Compen-sation ($)(5)	Total ($)
Steven J. Newby	2012	$354,673	$—	$ 393,738	$350,000	$ 7,500	$1,105,911
President and Chief Executive Officer	2011	295,500	250,000	—	—	8,865	554,365
Matthew S. Harrison	2012	$278,872	$—	$ 236,332	$295,000	$ 27,116	$837,320
Senior Vice President and Chief Financial Officer (6)	2011	87,176	240,000	—	911,000	—	1,238,176
Brock M. Degeyter	2012	$221,983	$75,000	$ 231,635	$250,000	$ 5,097	$783,715
Senior Vice President, General Counsel (7)	2011	—	—	—	—	—	—

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(1) The amounts shown for 2012 represent that portion of the named executive officers' base salary paid by the Predecessor prior to the IPO and the portion allocated to SMLP after the IPO. For a discussion of the cost allocation methodology, please refer to "General and Administrative Expenses Allocation" in Item 13 below.

(2) For 2012, the amount relates to Mr. Degeyter's signing bonus, and for 2011, the amounts relate to discretionary bonuses to Messrs. Newby and Harrison, and also include Mr. Harrison's $25,000 signing bonus. The signing bonuses for Mr. Harrison and Mr. Degeyter were provided for in their respective employment agreements and paid by the Predecessor as a result of their commencing employment with Summit Investments.

(3) Represents incentive bonus earned under our annual incentive bonus program for the year ended December 31, 2012 and paid in March 2013. For a discussion of the determination of these amounts, please read "—Elements of Compensation—Annual Incentive Compensation" below. The amounts shown for 2012 represent that portion of the

named executive officers' annual bonus that has been allocated to SMLP. For a discussion of the cost allocation methodology, please refer to "General and

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Administrative Expenses Allocation" in Item 13 below. Prior to 2012, our named executive officers received discretionary bonuses.
(4) Amounts shown in this column for 2012 for Messrs. Newby, Harrison and Degeyter reflect the grant date fair value of the phantom unit awards granted to the named executive officers in connection with the IPO, in accordance with FASB ASC Topic 718. For additional information, please refer to "Elements of Compensation – Long-Term Equity Based Compensation Awards>' The amount shown in this column for 2011 for Mr. Harrison reflects the grant date fair value of his pre-IPO equity awards in accordance with FASB ASC Topic 718. See Note 9 to the audited consolidated financial statements for the assumptions made in valuing these awards.
(5) Amounts shown in this column for 2012 and 2011 include employer contributions under the 401(k) Plan for all named executive officers. Also, pursuant to the terms of his employment agreement, the amount includes $19,616 for relocation expense reimbursement paid to Mr. Harrison in 2012.
(6) Mr. Harrison commenced employment with us on September 15, 2011. Amount shown for 2011 represents the base salary earned by Mr. Harrison for his partial year of employment in 2011.
(7) Mr. Degeyter commenced employment with us on January 18, 2012. Amount shown for 2012 represents the base salary earned by Mr. Degeyter for his partial year of employment in 2012.
Narrative Disclosure to Summary Compensation Table
Elements of Compensation. The primary elements of compensation for the named executive officers are base salary, annual incentive compensation and long-term equity-based compensation awards. The named executive officers also receive certain retirement, health, welfare and additional benefits as described below.
Base Salary. Base salaries for our named executive officers have generally been set at levels deemed necessary to attract and retain individuals with superior talent. None of our named executive officers received any base salary adjustments or increases during 2012. The base salaries of our named executive officers, a portion of which are allocated to and reimbursed by the partnership, are set forth in the following table:

Name and Principal Position	Base Salary
Steven J. Newby President and Chief Executive Officer	$400,000
Matthew S. Harrison Senior Vice President and Chief Financial Officer	295,000
Brock M. Degeyter Senior Vice President and General Counsel (1)	250,000

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(1) In March of 2013, Mr. Degeyter's base salary was adjusted upward to $265,000 to bring his salary in line with the current market.
Annual Incentive Compensation. For 2012, Messrs. Newby, Harrison and Degeyter had target bonuses of $300,000, $221,250, $187,500 respectively, or 75% of their base salaries. In March of 2013, Mr. Newby's target bonus opportunity was adjusted upward to 100% of his base salary to bring it in line with the current market; however, the adjustment does not go into effect until the 2013 bonus year.
Quantitative factors, as reflected in the corporate scorecard applicable to the senior leadership team (the "SLT Scorecard") determined one-half of Messrs. Harrison and Degeyter's incentive compensation, while their respective business unit scorecards accounted for the remaining half. For Mr. Newby, the SLT Scorecard determined his entire annual incentive bonus for 2012.
The SLT Scorecard contained seven objective factors related to the corporate enterprise's key objectives for 2012, including Adjusted EBITDA thresholds, operating expense and safety goals, capital projects, corporate growth and relative success of the company's initial public offering. Although we narrowly missed our adjusted EBITDA target for the year, we achieved or exceeded the performance measurement target on all of the other factors. As a result, Messrs. Newby, Harrison and Degeyter were awarded 114% of target for the portion of their bonuses based on the SLT Scorecard.
Mr. Newby's annual bonus payout was adjusted upward to $425,000, which is approximately 142% of his target bonus for 2012, primarily due to his leadership in achieving strong operational results for our business, including strong

safety, operational and cost performance, and his significant contributions to the IPO and the company's other strategic transactions.

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Mr. Harrison was awarded 100% of target for the portion of his bonus based on the performance of the finance and accounting business units. In total, Mr. Harrison's annual bonus payout was adjusted upward to $250,000, which is approximately 113% of his target bonus for 2012, primarily due to his significant contributions to the amendment and restatement of the revolving credit facility, the IPO, Summit Investments' acquisition of the Red Rock Gathering system, and the company's successful integration of the Grand River system.
Mr. Degeyter was awarded 127% of target for the portion of his bonus based on the performance of the legal business unit. In total, Mr. Degeyter's annual bonus payout was adjusted upward to $250,000, which is approximately 133% of his target bonus for 2012, primarily due to his significant contributions to the IPO, Summit Investments' acquisition of the Red Rock Gathering system, and the company's various legal initiatives.
Only a portion of the named executive officers' bonus amounts are allocated to and reimbursed by the Partnership. For a discussion of the cost allocation methodology, please refer to "G&A Expense Allocation" in Item 13 below.
Long-Term Equity-Based Compensation Awards. In connection with our IPO, we adopted a new long-term equity incentive plan, which is discussed in more detail under "2012 Long-Term Incentive Plan" below. In 2012, the Board granted 17,500, 14,750 and 12,500 phantom units to Messrs. Newby, Harrison and Degeyter, respectively. The phantom units are expected to vest on the third anniversary of the pricing of our IPO, subject to accelerated vesting in limited circumstances. Messrs. Newby, Harrison and Degeyter received distribution equivalent rights for each phantom unit, providing for a lump sum cash amount equal to the accrued distributions from the grant date of the phantom units to be paid in cash upon the vesting date.
Retirement, Health and Welfare and Additional Benefits. The named executive officers are eligible to participate in such employee benefit plans and programs as we may from time to time offer to our employees, subject to the terms and eligibility requirements of those plans. The named executive officers are eligible to participate in a tax-qualified 401(k) defined contribution plan to the same extent as all of our other employees. In 2012, we made a fully vested contribution on behalf of each of the 401(k) plan's participants equal to 3% of such participant's eligible salary for the year. Also, in 2012, pursuant to the terms of his employment agreement, Mr. Harrison was reimbursed $19,616 for relocation expenses.
Outstanding Equity Awards at December 31, 2012
The following table provides information regarding the phantom unit awards held by the named executive officers as of December 31, 2012.

Name	Number of phantom units that have not vested (1)	Market value of phantom units that have not vested (2)
Steven J. Newby	17,500	$347,025
Matthew S. Harrison	14,750	292,493
Brock M. Degeyter	12,500	247,875

(1) All phantom units granted to the named executive officers in connection with the IPO vest on September 28, 2015, the third anniversary of the pricing of our IPO, subject to accelerated vesting on the occurrence of any of the following events: (i) a termination of the officer's employment other than for cause, (ii) a termination of the officer's employment by the officer for good reason (as defined in the officer's employment agreement), (iii) a termination of the officer's employment by reason of the officer's death or disability or (iv) a Change in Control (as defined in the applicable award agreement).
(2) Based on the closing price of SMLP's publicly traded common units on December 31, 2012.
Employment and Severance Arrangements. Our named executive officers each have employment agreements with Summit Investments.
Mr. Newby's employment agreement, which was amended and restated as of August 13, 2012, has an initial term of three years, and is then automatically extended for successive one-year periods, unless either party gives notice of non-extension to the other no later than 90 days prior to the expiration of the then-applicable term. Mr. Newby's employment agreement provides for an annual base salary of $400,000, and a performance-based bonus ranging from 0% to 150% of base salary, with a target of 75% of base salary. In March of 2013, Mr. Newby's target bonus opportunity was adjusted upward to 100% of his base salary. Mr. Newby is entitled to receive a prorated annual bonus

(based on target) if his employment is terminated by the company without cause or due to death or disability. In addition, Mr. Newby's employment agreement provides that the company will reimburse him for tax preparation services and ongoing tax advice up to $10,000 per year, as well as an annual executive physical at a medical facility of his choice.

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Mr. Newby's employment agreement provides for a cash severance payment upon a termination by the company without cause or by Mr. Newby for good reason, which is defined generally as the officer's termination of employment within two years after the occurrence of (i) a material diminution in the named executive officer's authority, duties or responsibilities, (ii) a material diminution in the officer's base compensation, (iii) a material change in the geographic location at which the officer must perform his services under the agreement or (iv) any other action or inaction that constitutes a material breach of the employment agreement by the company (each a "Qualifying Termination"). In the event of a Qualifying Termination other than in the period beginning six months prior to a change in control of the company and ending on the 12-month anniversary of such a change in control, Mr. Newby's severance payment will be equal to the sum of his annual base salary and his annual bonus payable in respect of the immediately preceding year. If a Qualifying Termination occurs during the period beginning six months prior to a change in control and ending on the 12-month anniversary of such a change in control, Mr. Newby's severance payment will increase to two times the sum of his annual base salary and the immediately preceding year's bonus. Following any termination of employment other than one resulting from non-extension of the term, his employment agreement provides that Mr. Newby will be subject to a post-termination non-competition covenant through the severance period, and, following any termination of employment, Mr. Newby will be subject to a one-year post-termination non-solicitation covenant.

If Mr. Newby's employment is terminated due to non-extension of the term, the company may choose to subject him to a non-competition covenant for up to one year post-termination. If the company exercises this "noncompete option", then Mr. Newby would be entitled to a severance payment in an amount equal to the sum of his annual base salary and annual bonus payable in respect of the preceding year, multiplied by a fraction, the numerator of which is equal to the number of days from the date of termination through the expiration of the restricted period (as elected by us) and the denominator of which is 365. In this case, the severance payment will be payable in equal installments over the restricted period.

Mr. Newby's employment agreement also provides that all equity awards granted to Mr. Newby under the LTIP and held by him as of immediately prior to a change in control of us will become fully vested immediately prior to the change in control.

Mr. Newby's employment agreement provides that, if any portion of the payments or benefits provided to Mr. Newby would be subject to the excise tax imposed in connection with Section 280G of the Internal Revenue Code, then the payments and benefits will be reduced if such reduction would result in a greater after-tax payment to Mr. Newby.

Mr. Harrison's employment agreement, dated September 15, 2011, has an initial term of two years, and is then automatically extended for successive one-year periods, unless either party gives notice of non-extension to the other no later than 90 days prior to the expiration of the then-applicable term. Mr. Harrison's employment agreement provides for an annual base salary of $295,000 and a performance-based bonus ranging from 0% to 150% of base salary, with a target of 75% of base salary. Mr. Harrison's employment agreement also provides for reimbursement of up to $60,000 in relocation expenses incurred in relocating to Atlanta, Georgia, and reimbursement for tax preparation expenses in the amount of $10,000 per year.

Mr. Harrison's employment agreement also provides for a cash severance payment upon a termination by the company without cause or by Mr. Harrison for good reason, which is defined generally as the officer's termination of employment within two years after the occurrence of (i) a material diminution in the named executive officer's authority, duties or responsibilities, (ii) a material diminution in the officer's base compensation, (iii) a material change in the geographic location at which the officer must perform his services under the agreement or (iv) any other action or inaction that constitutes a material breach of the employment agreement by the company. Mr. Harrison's employment agreement provides that the severance payment will be equal to the sum of his annual base salary and the annual bonus payable in respect of the preceding year, multiplied by a fraction, the numerator of which is equal to the number of days in the period beginning on the date of termination and ending on the later of (a) the last day of the then-applicable term of the employment agreement and (b) the first anniversary of the date of termination (the "severance period") and the denominator of which is 365. The severance payment is payable in equal installments during the severance period.

Following any termination of employment other than one resulting from non-extension of the term, the employment agreement provides that Mr. Harrison will be subject to a post-termination non-competition covenant through the severance period, and, following any termination of employment, Mr. Harrison will be subject to a one-year post-termination non-solicitation covenant.

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If Mr. Harrison's employment is terminated due to non-extension of the term, the company may choose to subject him to a non-competition covenant for up to one year post-termination. If the company exercises this "noncompete option", then Mr. Harrison would be entitled to a severance payment in an amount equal to the sum of his annual base salary and annual bonus payable in respect of the preceding year, multiplied by a fraction, the numerator of which is equal to the number of days from the date of termination through the expiration of the restricted period (as elected by the company) and the denominator of which is 365. In this case, the severance payment will be payable in equal installments over the restricted period.

Mr. Degeyter's employment agreement, dated January 18, 2012, is substantially identical to Mr. Harrison's employment agreement, except that it (i) provides for an annual base salary of $250,000, (ii) does not provide for reimbursement for relocation expenses or tax preparation services, and (iii) does include a $75,000 cash signing bonus that was paid in March 2012, and a $75,000 cash retention bonus that was paid in February 2013.

2012 Long-Term Incentive Plan

Our general partner approved the LTIP pursuant to which eligible officers (including the named executive officers), employees, consultants and directors of our general partner and its affiliates are eligible to receive awards with respect to our equity interests, thereby linking the recipients' compensation directly to SMLP's performance. A total of 5,000,000 common units was reserved for issuance, pursuant to and in accordance with its terms. The description of the LTIP set forth below is a summary of the material features of the LTIP; however it is not a complete description of all of the provisions of the LTIP.

The LTIP provides for the grant, from time to time at the discretion of the board of directors or compensation committee of our general partner, of unit awards, restricted units, phantom units, unit options, unit appreciation rights, distribution equivalent rights, profits interest units and other unit-based awards. Subject to adjustment in the event of certain transactions or changes in capitalization, an aggregate of 125,000 common units may be delivered pursuant to awards under the LTIP. Units that are canceled or forfeited will be available for delivery pursuant to other awards. The LTIP is administered by our general partner's board of directors, though such administration function may be delegated to a committee (including the compensation committee) that may be appointed by the board to administer the LTIP. The LTIP is designed to promote our interests, as well as the interests of our unitholders, by rewarding eligible officers, employees, consultants and directors for delivering desired performance results, as well as by strengthening our ability to attract, retain and motivate qualified individuals to serve as directors, consultants and employees.

In 2012, the board of directors of our general partner granted 7,577 common units in the aggregate to three of our directors and granted 125,000 phantom units with distribution equivalent rights to certain key employees that provide services for us, including executive officers, pursuant to the LTIP. Of the employee units, 17,500, 14,750 and 12,500 phantom units were granted to Messrs. Newby, Harrison and Degeyter, respectively. The phantom units granted to our named executive officers and other employees are expected to vest on the third anniversary of the consummation of our IPO, subject to accelerated vesting on the occurrence of any of the following events: (i) a termination of the officer's employment other than for cause, (ii) a termination of the officer's employment by the officer for good reason (as defined in the officer's employment agreement), (iii) a termination of the officer's employment by reason of the officer's death or disability or (iv) a Change in Control (as defined in the applicable award agreement). Holders of phantom units are entitled to receive distribution equivalent rights for each phantom unit, providing for a lump sum cash amount equal to the accrued distributions from the grant date of the phantom units to be paid in cash upon the vesting date.

Restricted Units and Phantom Units. A restricted unit is a common unit that is subject to forfeiture. Upon vesting, the forfeiture restrictions lapse and the recipient holds a common unit that is not subject to forfeiture. A phantom unit is a notional unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit or on a deferred basis upon specified future dates or events or, in the discretion of the administrator, cash equal to the fair market value of a common unit. The administrator of the LTIP may make grants of restricted and phantom units under the LTIP that contain such terms, consistent with the LTIP, as the administrator may determine are appropriate, including the period over which restricted or phantom units will vest. The administrator of the LTIP may, in its discretion, base vesting on the grantee's completion of a period of service or upon the achievement of specified financial objectives or other criteria or upon a change of control (as defined in the LTIP) or as otherwise described in an award agreement. Distributions made by us with respect to awards of restricted units may be subject to the same vesting requirements as the restricted units.

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Distribution Equivalent Rights. The administrator of the LTIP, in its discretion, may also grant distribution equivalent rights, either as standalone awards or in tandem with other awards. Distribution equivalent rights are rights to receive an amount in cash, restricted units or phantom units equal to all or a portion of the cash distributions made on units during the period an award remains outstanding.

Source of Common Units; Cost. Common units to be delivered with respect to awards may be newly-issued units, common units acquired by us or our general partner in the open market, common units already owned by our general partner or us, common units acquired by our general partner directly from us or any other person or any combination of the foregoing.

Amendment or Termination of Long-Term Incentive Plan. The administrator of the LTIP, at its discretion, may terminate the LTIP at any time with respect to the common units for which a grant has not previously been made. The LTIP will automatically terminate on the 10th anniversary of the date it was initially adopted by our general partner. The administrator of the LTIP will also have the right to alter or amend the LTIP or any part of it from time to time or to amend any outstanding award made under the LTIP, provided that no change in any outstanding award may be made that would materially impair the rights of the participant without the consent of the affected participant.

Compensation Committee Report

As our general partner does not have a compensation committee, the board of directors of our general partner provides the oversight, administers and makes decisions regarding our compensation policies and plans. Additionally, the board of directors of our general partner generally reviews and discusses the Compensation Discussion and Analysis with senior management of our general partner as a part of our governance practices. Based on this review and discussion, the board of directors of our general partner has directed that the Compensation Discussion and Analysis be included in this report for filing with the SEC.

Members of the Board of Directors of Summit Midstream GP, LLC

Thomas K. Lane	Andrew F. Makk	Curtis A. Morgan
Steven J. Newby	Jerry L. Peters	Jeffery R. Spinner
Susan Tomasky		

Director Compensation

Mr. Morgan and the independent directors, which currently include Mr. Peters and Ms. Tomasky, each received a $50,000 annual retainer and $50,000 in annual unit compensation in 2012. These amounts were paid in conjunction with the individual's appointment to the board of directors. In addition, for 2012, the following cash payments were approved:

- the chairman of the Audit Committee received an additional annual retainer of $15,000;
- the chairman of the Conflicts Committee received an additional annual retainer of $7,500;
- each independent member of any committee (other than the chairman) received an additional annual retainer of $1,500;
- and the chairman of any other committee is entitled to an annual retainer of $7,500.

Board members are reconsidered for appointment on the one-year anniversary of their most recent appointment. We intend to pay subsequent retainers and compensation in connection with a member's reappointment to the board of directors. Our general partner did not have any independent directors in 2011. We do not compensate employee directors for their services as directors.

We reimburse all directors for travel and other related expenses in connection with attending board and committee meetings and board-related activities.

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The following table shows the director compensation in 2012.

Name	Fees earned or paid in cash	Other fees	Unit awards (1)	Total
Thomas K. Lane	$—	$—	$—	$—
Andrew F. Makk	—	—	—	—
Curtis A. Morgan	50,000	—	50,000	100,000
Steven J. Newby	—	—	—	—
Jerry L. Peters	50,000	16,500	50,000	116,500
Jeffery R. Spinner	—	—	—	—
Susan Tomasky	50,000	9,000	50,000	109,000

(1) Amount shown represents the grant date fair value of the unit awards as determined in accordance with FASB ASC Topic 718. These unit awards were fully vested on the date of grant.

Compensation Committee Interlocks and Insider Participation

As previously discussed, the Board is not required to maintain, and does not maintain a compensation committee. Mr. Newby, who serves as the President and Chief Executive Officer of our general partner, participates in his capacity as a director in the deliberations of the Board concerning executive officer compensation. In addition, Mr. Newby makes recommendations to the Board regarding named executive officer compensation but abstains from any decisions regarding his compensation.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

The following table sets forth certain information regarding the beneficial ownership of our common units as of February 28, 2013 and the related transactions by:

- each person who is known to us to beneficially own 5% or more of such units to be outstanding (based solely on Schedules 13D and 13G filed with the SEC);
- our general partner;
- each of the directors and named executive officers of our general partner; and
- all of the directors and executive officers of our general partner as a group.

All information with respect to beneficial ownership has been furnished by the respective directors, officers or 5% or more unitholders as the case may be.

The amounts and percentage of units beneficially owned are reported on the basis of regulations of the SEC governing the determination of beneficial ownership of securities. Under the rules of the SEC, a person is deemed to be a beneficial owner of a security if that person has or shares voting power, which includes the power to vote or to direct the voting of such security, or investment power, which includes the power to dispose of or to direct the disposition of such security. In computing the number of common units beneficially owned by a person and the percentage ownership of that person, common units subject to options or warrants held by that person that are currently exercisable or exercisable within 60 days of February 28, 2013, if any, are deemed outstanding, but are not deemed outstanding for computing the percentage ownership of any other person. Except as indicated by footnote, the persons named in the table below have sole voting and investment power with respect to all units shown as beneficially owned by them, subject to community property laws where applicable.

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The percentage of units beneficially owned is based on a total of 24,412,427 common units and 24,409,850 subordinated units outstanding as of February 28, 2013.

Name Of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned	Subordinated Units Beneficially Owned	Percentage of Subordinated Units Beneficially Owned	Percentage of Total Common and Subordinated Units Beneficially Owned
Summit Investments (1) (2)	10,029,850	41.1 %	24,409,850	100.0 %	70.5 %
Energy Capital Partners II, LLC (1) (3) (4)	10,029,850	41.1 %	24,409,850	100.0 %	70.5 %
Kayne Anderson Capital Advisors, L.P. (5)	1,506,214	6.2 %	—	—	3.1 %
OppenheimerFunds, Inc. (6)	1,224,280	5.0 %	—	—	2.5 %
Steven J. Newby (1)	—	—	—	—	—
Matthew S. Harrison (1)	—	—	—	—	—
Brock M. Degeyter (1)	—	—	—	—	—
Thomas K. Lane (4) (7)	40,000	*	—	—	*
Andrew F. Makk (4)	—	—	—	—	—
Curtis A. Morgan (8)	2,500	*	—	—	*
Jerry L. Peters (9)	2,500	*	—	—	*
Jeffery R. Spinner (4)	—	—	—	—	—
Susan Tomasky (10)	2,577	*	—	—	*
All directors and executive officers as a group (consisting of 12 persons)	47,577	*	—	—	*

* An asterisk indicates that the person or entity owns less than one percent.

(1) Summit Investments owns 100% of our general partner, 41.1% of our outstanding common units and 100.0% of our outstanding subordinated units. Energy Capital Partners II, LLC ("ECP II") and its parallel and co-investment funds (the "ECP Funds" and together with ECP II, "ECP") hold in the aggregate, an approximate 90.6% ownership interest in Summit Investments. ECP II is the general partner of the general partner of each of the ECP Funds that holds membership interests in Summit Investments and has voting and investment control over the securities held thereby. Accordingly, ECP may be deemed to indirectly beneficially own the 10,029,850 common units and 24,409,850 subordinated units held by Summit Investments. The subordinated units held by Summit Investments may be converted into common units on a one-for-one basis after expiration of the subordination period (as defined in the Partnership Agreement).

(2) The address for this person or entity is 2100 McKinney Avenue, Suite 1250, Dallas, Texas 75201.

(3) ECP holds a 90.6% ownership interest in Summit Investments and may therefore be deemed to indirectly beneficially own the 10,029,850 common units and 24,409,850 subordinated units held by Summit Investments. Because of its ownership interest in Summit Investments, ECP is entitled to elect four directors of Summit Investments. In addition, Thomas Lane (who is a managing member of ECP II), Andrew Makk (who is a principal of ECP II) and Jeffery Spinner (who is employed by ECP II) are each directors of our general partner. Neither Mr. Lane, Mr. Makk nor Mr. Spinner are deemed to beneficially own, and they disclaim beneficial ownership of, any common units or subordinated units held by our general partner or Summit Investments.

(4) The address for this person or entity is 51 John F. Kennedy Parkway, Suite 200, Short Hills, New Jersey 07078.

(5) The address for this person or entity is 1800 Avenue of the Stars, 3rd Floor, Los Angeles, California 90067.

(6) The address for this person or entity is Two World Financial Center, 225 Liberty Street, New York, New York 10281.

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(7) Includes 20,000 common units held by Lane Ventures LLC ("Lane Ventures"). Two of Mr. Lane's estate planning trusts collectively own a majority of the membership interests in Lane Ventures and as a result, Mr. Lane may be deemed to indirectly beneficially own the common units held by Lane Ventures.

(8) The address for this person or entity is 800 Long Ridge Road, Stamford, Connecticut 06927.

(9) The address for this person is 450 Regency Parkway, Suite 400, Omaha, Nebraska 68114.

(10) The address for this person is 90 Ashbourne Road, Bexley, Ohio 43209.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table provides information as of December 31, 2012 with respect to the Company's common units that may be issued under the 2012 Long-Term Incentive Plan.

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a) (1)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	125,000	n/a	4,868,423
Equity compensation plans not approved by security holders	n/a	n/a	n/a
Total	125,000	n/a	4,868,423

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(1) Amount shown represents phantom unit awards outstanding under the LTIP at December 31, 2012. The awards are expected to be settled in common units upon the applicable vesting date and are not subject to an exercise price.

2012 Long-Term Incentive Plan. In connection with the IPO, our general partner approved the LTIP, pursuant to which eligible officers, employees, consultants and directors of our general partner and its affiliates are eligible to receive awards with respect to our equity interests. The LTIP is designed to promote our interests, as well as the interests of our unitholders, by rewarding eligible officers, employees, consultants and directors for delivering desired performance results, as well as by strengthening our ability to attract, retain and motivate qualified individuals to serve as directors, consultants and employees. A total of 5,000,000 common units was reserved for issuance, pursuant to and in accordance with the LTIP.

The LTIP is administered by our general partner's board of directors. The LTIP provides for the grant, from time to time at the discretion of the board of directors, of unit awards, restricted units, phantom units, unit options, unit appreciation rights, distribution equivalent rights, profits interest units and other unit-based awards. Units that are cancelled or forfeited are available for delivery pursuant to other awards.

Common units to be delivered with respect to awards may be newly issued units, common units acquired by us or our general partner in the open market, common units already owned by our general partner or us, common units acquired by our general partner directly from us or any other person or any combination of the foregoing.

The general partner's board of directors, at its discretion, may terminate the LTIP at any time with respect to the common units for which a grant has not previously been made. The LTIP will automatically terminate on the 10th anniversary of the date it was initially adopted by our general partner. The general partner's board of directors also has the right to alter or amend the LTIP or any part of it from time to time or to amend any outstanding award made under the LTIP, provided that no change in any outstanding award may be made that would materially impair the rights of the participant without the consent of the affected participant.

Item 13. Certain Relationships and Related Transactions, and Director Independence.

As of December 31, 2012, Summit Investments owned 10,029,850 common units and 24,409,850 subordinated units, representing a combined 69.1% limited partner interest in us. In addition, Summit Investments owns and controls our general partner, which owns a 2.0% general partner interest in us and all of our incentive distribution rights.

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Distributions and Payments to our General Partner and its Affiliates

The following summarizes the distributions and payments to be made by us to our general partner and its affiliates in connection with our formation, ongoing operation and our liquidation. These distributions and payments were determined by and among affiliated entities and, consequently, are not the result of arm's-length negotiations.

Formation Stage

The consideration received by our general partner and its affiliates prior to or in connection with our IPO:

- 10,029,850 common units;
- 24,409,850 subordinated units;
- all of our incentive distribution rights;
- 2.0% general partner interest; and
- an $88.0 million cash payment from the proceeds of the offering.

Operational Stage

Distributions of available cash to our general partner and its affiliates. We will initially make cash distributions 98.0% to our unitholders pro rata, including Summit Investments, as the holder of an aggregate of 34,439,700 common units and subordinated units, and 2.0% to our general partner, assuming it makes any capital contributions necessary to maintain its 2.0% general partner interest in us. In addition, if distributions exceed the minimum quarterly distribution and target distribution levels, the incentive distribution rights held by our general partner will entitle our general partner to increasing percentages of the distributions, up to 48.0% of the distributions above the highest target distribution level.

Assuming we have sufficient cash available to pay the aggregate annualized minimum quarterly distribution on all of our outstanding units for four quarters, our general partner and its affiliates would receive an annual distribution of approximately $1.6 million on its 2.0% general partner interest and Summit Investments would receive an annual distribution of approximately $55.1 million on its common units and subordinated units.

Payments to our general partner and its affiliates. Our general partner does not receive a management fee or other compensation for its management of us. Under our partnership agreement, we reimburse our general partner and its affiliates for certain expenses incurred on our behalf, including, without limitation, salary, bonus, incentive compensation and other amounts paid to our general partner's employees and executive officers who perform services necessary to run our business. In addition, we reimburse our general partner for compensation, travel and entertainment expenses for the directors serving on the board of directors of our general partner and the cost of director and officer liability insurance. Our partnership agreement provides that our general partner determines in good faith the expenses that are allocable to us.

Withdrawal or removal of our general partner. If our general partner withdraws or is removed, its general partner interest and its incentive distribution rights will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.

Liquidation Stage

Upon our liquidation, our partners, including our general partner, will be entitled to receive liquidating distributions according to their particular capital account balances.

Agreements with Affiliates

We have various agreements with certain of our affiliates, as described below. These agreements have been negotiated among affiliated parties and, consequently, are not the result of arm's-length negotiations.

General and Administrative Expenses Allocation. Under our partnership agreement, we reimburse our general partner and its affiliates for certain expenses incurred on our behalf, including, without limitation, salary, bonus, incentive compensation and other amounts paid to our general partner's employees and executive officers who perform services necessary to run our business. In addition, we reimburse our general partner for compensation, travel and entertainment expenses for the directors serving on the board of directors of our general partner and the cost of director and officer liability insurance. Our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us. Amounts paid to reimburse the general partner for these expenses were approximately $1.2 million in 2012.

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Electricity Management Services Agreement. We entered into a consulting arrangement with Equipower Resources Corp., whereby they assist DFW Midstream with managing its electricity price risk. Equipower Resources Corp. is an affiliate of our Sponsor, Energy Capital Partners. Amounts paid for such services were as follows:

	Year ended December 31,		
	2012	2011	2010
	(In thousands)		
Payments for electricity management consulting services	$204	$11	$—

Curtis A. Morgan, a member of the board of directors of our general partner, is the President and Chief Executive Officer of EquiPower Resources Corp.

Promissory Notes Payable to Sponsors. In conjunction with the Grand River Transaction, Summit Investments executed $200.0 million of promissory notes, on an unsecured basis, with its Sponsors. The notes had an 8% interest rate and were scheduled to mature in October 2013. In May 2012, Summit Holdings borrowed $163.0 million under the revolving credit facility and used a portion of the same borrowings to prepay $160.0 million principal amount of the promissory notes payable to the Sponsors. Then in July 2012, an additional $50.0 million was borrowed under the revolving credit facility, a portion of which was used to pay the remaining $49.2 million principal amount of the promissory notes payable to Sponsors (inclusive of accrued pay-in-kind interest).

In accordance with the terms of the underlying note agreement, prior to their repayment in July 2012, the Predecessor elected to make all interest payments on the note in kind. The amount of interest paid in kind and accrued to the balance of the notes for year ended December 31, 2012, was approximately $6.3 million, of which the Company capitalized $0.9 million of interest expense related to costs incurred on capital projects under construction.

DFW Class B Membership Interests. Certain current and former employees and members of management, or the DFW employees, of DFW Management, hold Class B membership interests representing an aggregate 4.4% net profits interests in DFW Midstream. The net profits interests allow the DFW employees to share in distributions by DFW Midstream only after we have received distributions in an amount equal to any capital contributions made subsequent to the date of grant, subject to the terms set forth in the underlying award agreement and the limited liability company agreement of DFW Management.

The net profits interests were granted subject to four-year vesting schedules, and provide for accelerated vesting in certain circumstances, including termination without cause or by reason of death or disability. Unvested profits interests are forfeited upon termination for any other reason. Pursuant to the DFW Midstream limited liability company agreement, the vested net profits interests are subject to a repurchase right, at our option, for one year following the holder's termination of employment. In the event of the termination of an employee's employment due to death, disability, termination by DFW Midstream without cause or a voluntary resignation after the fourth anniversary of the employee's start date with DFW Midstream, the repurchase price will be equal to the value of the net profits interests in a hypothetical liquidation of DFW Midstream pursuant to the rights and preferences set forth in the limited liability agreement, assuming all assets were sold for their fair market value.

In August 2012, four former DFW employees filed a claim in the Court of Chancery of the State of Delaware relating to the net profits interests granted to them prior to their separation from DFW Midstream. For additional information, see Item 3. Legal Proceedings and Note 11 to the audited consolidated financial statements.

Review, Approval and Ratification of Related-Person Transactions

On March 7, 2013, the board of directors of our general partner adopted a policy for the identification, review and approval of certain related person transactions. The policy provides for the review and (as appropriate) approval by the Conflicts Committee of SMLP's general partner of transactions between SMLP and its subsidiaries, on the one hand, and related persons (as that term is defined in SEC rules), on the other hand. Pursuant to the policy, the General Counsel of SMLP's general partner is charged with primary responsibility for determining whether, based on the facts and circumstances, a proposed transaction is a related person transaction.

For purposes of the policy, a "related person" is any director or executive officer of SMLP's general partner, any nominee for director, any unitholder known to SMLP to be the beneficial owner of more than 5% of any class of the SMLP's common units, and any immediate family member, affiliate or controlled subsidiary of any such person. A "related person transaction" is generally a transaction in which SMLP is, or SMLP's general partner or any of

SMLP's subsidiaries is, a participant, where the amount involved exceeds $120,000, and a related person has a direct or indirect material interest. Transactions resolved under the conflicts provision of the partnership agreement are not required to be reviewed or approved under the policy.

If, after weighing all of the facts and circumstances, the general counsel of SMLP's general partner determines that a proposed transaction is a related person transaction that requires review or approval and the transaction meets certain monetary thresholds or involves certain related persons, management must present the proposed transaction to the Conflicts Committee for advance approval. If the transaction does not meet the designated monetary threshold or involve certain related persons, management presents the transaction(s) to the Committee for their review on a quarterly basis.

The policy described above was adopted by the board of directors of our general partner on March 7, 2013, and as a result the transactions described in "—Agreements with Affiliates" above were not reviewed under such policy.

Director Independence

Although most companies listed on the New York Stock Exchange are required to have a majority of independent directors serving on the board of directors of the listed company, the New York Stock Exchange does not require a listed limited partnership like us to have, and we do not intend to have, a majority of independent directors on the board of directors of our general partner.

Item 14. Principal Accounting Fees and Services.

Audit Fees. Our audit committee has ratified Deloitte & Touche LLP, Independent Registered Public Accounting Firm, to audit the books, records and accounts of SMLP for the year ended December 31, 2012. The fees billed by Deloitte & Touche LLP for the audit of consolidated financial statements and other services rendered for the years ended December 31, 2012 and 2011 follow.

	Year ended December 31,	
	2012	2011
Audit fees	$1,602,276	$430,500
Audit-related fees	131,500	107,600
Tax fees	254,624	73,093
All other fees (1)	—	92,058
Total	$1,988,400	$703,251

(1) Fees related to IPO readiness project.

Pre-approval Policy. Pursuant to its charter, the Audit Committee is responsible for the appointment, compensation, retention and oversight of SMLP's independent auditor (including resolution of disagreements between management and the independent auditor regarding financial reporting). The Audit Committee shall have sole authority to pre-approve all audit, audit-related and permitted non-audit engagements with the independent auditor, including the fees and other terms of such engagements. The independent auditor shall report directly to the Audit Committee. The Audit Committee may consult with management but may not delegate these responsibilities to management.

PART IV

Item 15. Exhibits, Financial Statement Schedules.

(a)(1) Financial Statements

Included in Part II, Item 8, of this report:

Summit Midstream Partners, LP and Subsidiaries:

(2) Financial Statement Schedules

All schedules are omitted because the required information is inapplicable or the information is presented in the financial statements or the notes thereto.

(3) Exhibit Index

An “Exhibit Index” has been filed as part of this Report beginning on the following page and is incorporated herein by this reference.

Schedules other than those listed above are omitted because they are not required, are not material, are not applicable, or the required information is shown in the financial statements or notes thereto.

In reviewing the agreements included as exhibits to this annual report, please remember they are included to provide you with information regarding their terms and are not intended to provide any other factual or disclosure information about the Company or the other parties to the agreements. The agreements contain representations and warranties by each of the parties to the applicable agreement. These representations and warranties have been made solely for the benefit of the other parties to the applicable agreement and:

- should not in all instances be treated as categorical statements of fact, but rather as a way of allocating the risk to one of the parties if those statements prove to be inaccurate;
- have been qualified by disclosures that were made to the other party in connection with the negotiation of the applicable agreement, which disclosures are not necessarily reflected in the agreement;
- may apply standards of materiality in a way that is different from what may be viewed as material to you or other investors; and
- were made only as of the date of the applicable agreement or such other date or dates as may be specified in the agreement and are subject to more recent developments.

Accordingly, these representations and warranties may not describe the actual state of affairs as of the date they were made or at any other time.

(b) Exhibit Index

Exhibit number	Description
3.1	First Amended and Restated Agreement of Limited Partnership of Summit Midstream Partners, LP, dated as of October 3, 2012 (Incorporated herein by reference to Exhibit 3.1 to SMLP's Current Report on Form 8-K dated October 4, 2012 (Commission File No. 001-35666))
3.2	Amended and Restated Limited Liability Company Agreement of Summit Midstream GP, LLC, dated as of October 3, 2012 (Incorporated herein by reference to Exhibit 3.2 to SMLP's Current Report on Form 8-K dated October 4, 2012 (Commission File No. 001-35666))

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3.3		Certificate of Limited Partnership of Summit Midstream Partners, LP (Incorporated herein by reference to Exhibit 3.1 to SMLP's Form S-1 Registration Statement dated August 21, 2012 (Commission File No. 333-183466))
3.4		Certificate of Formation of Summit Midstream GP, LLC (Incorporated herein by reference to Exhibit 3.4 to SMLP's Form S-1 Registration Statement dated August 21, 2012 (Commission File No. 333-183466))
4.1		Investor Rights Agreement, dated as of October 3, 2012, by and among EFS-S, LLC, Summit Midstream GP, LLC and Summit Midstream Partners, LLC (Incorporated herein by reference to Exhibit 4.1 to SMLP's Current Report on Form 8-K dated October 4, 2012 (Commission File No. 001-35666))
10.1		Amendment and Restatement Agreement giving effect to the form of Amended and Restated Revolving Credit Agreement (Incorporated herein by reference to Exhibit 10.1 to SMLP's Form S-1 Registration Statement dated August 21, 2012 (Commission File No. 333-183466))
10.2		Form of Amended and Restated Revolving Credit Agreement (included in Exhibit 10.1)
10.3		Contribution, Conveyance and Assumption Agreement, dated as of October 3, 2012, by and among Summit Midstream GP, LLC, Summit Midstream Partners, LP, Summit Midstream Holdings, LLC and Summit Midstream Partners, LLC (Incorporated herein by reference to Exhibit 10.1 to SMLP's Current Report on Form 8-K dated October 4, 2012 (Commission File No. 001-35666))
10.4	†	Amended and Restated Natural Gas Gathering Agreement, dated August 1, 2010, by and between DFW Midstream Services LLC, Chesapeake Energy Marketing, Inc., and Chesapeake Exploration, LLC (Incorporated herein by reference to Exhibit 10.6 to SMLP's Amendment No. 1 to its Form S-1 Registration Statement dated September 14, 2012 (Commission File No. 333-183466))
10.5	†	Amended and Restated Natural Gas Gathering Agreement, dated December 1, 2011, by and between DFW Midstream Services LLC and Carrizo Oil & Gas, Inc. (Incorporated herein by reference to Exhibit 10.7 to SMLP's Amendment No. 1 to its Form S-1 Registration Statement dated September 14, 2012 (Commission File No. 333-183466))
10.6	†	Second Amended and Restated Gas Gathering Agreement, dated November 1, 2010, by and between Willams Production RMT Company LLC and Encana Oil & Gas (USA) Inc. (Incorporated herein by reference to Exhibit 10.8 to SMLP's Amendment No. 1 to its Form S-1 Registration Statement dated September 14, 2012 (Commission File No. 333-183466))
10.7	†	Future Development Gas Gathering Agreement, dated October 1, 2011, by and between Encana Oil & Gas (USA) Inc., Grand River Gathering, LLC, and Summit Midstream Partners, LLC (Incorporated herein by reference to Exhibit 10.9 to SMLP's Amendment No. 1 to its Form S-1 Registration Statement dated September 14, 2012 (Commission File No. 333-183466))
10.8	†	Mamm Creek Gas Gathering Agreement, dated October 1, 2011, by and between Encana Oil & Gas (USA) Inc., Grand River Gathering, LLC, and Summit Midstream Partners, LLC (Incorporated herein by reference to Exhibit 10.10 to SMLP's Amendment No. 1 to its Form S-1 Registration Statement dated September 14, 2012 (Commission File No. 333-183466))
10.9	*	Amended and Restated Employment Agreement, dated August 13, 2012, by and between Summit Midstream Partners, LLC and Steven J. Newby (Incorporated herein by reference to Exhibit 10.11 to SMLP's Form S-1 Registration Statement dated August 21, 2012 (Commission File No. 333-183466))
10.10	*	Employment Agreement, dated September 15, 2011, by and between Summit Midstream Partners, LLC and Matthew S. Harrison (Incorporated herein by reference to Exhibit 10.12 to SMLP's Amendment No. 1 to its Form S-1 Registration Statement dated September 14, 2012 (Commission File No. 333-183466))

10.11	*	Employment Agreement, dated January 18, 2012, by and between Summit Midstream Partners, LLC and Brock M. Degeyter (Incorporated herein by reference to Exhibit 10.13 to SMLP's Amendment No. 1 to its Form S-1 Registration Statement dated September 14, 2012 (Commission File No. 333-183466))
10.12	*	Amended and Restated Employment Agreement, dated March 8, 2013, by and between Summit Midstream Partners, LLC and Brad N. Graves
10.13	*	Employment Agreement, dated September 19, 2012, by and between Summit Midstream Partners, LLC and Rene Casadaban (Incorporated herein by reference to Exhibit 10.15 to SMLP's Amendment No. 2 to its Form S-1 Registration Statement dated September 20, 2012 (Commission File No. 333-183466))

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10.14	*	Summit Midstream Partners, LP 2012 Long-Term Incentive Plan (Incorporated herein by reference to Exhibit 10.2 to SMLP's Current Report on Form 8-K dated October 4, 2012 (Commission File No. 001-35666))
10.15		Form of Phantom Unit Award Agreement (Incorporated herein by reference to Exhibit 10.5 to SMLP's Form S-1 Registration Statement dated August 21, 2012 (Commission File No. 333-183466))
10.16		Form of Director Unit Award Agreement (Incorporated herein by reference to Exhibit 10.3 to SMLP's Current Report on Form 8-K dated October 4, 2012 (Commission File No. 001-35666))
23.1		Consent of Deloitte & Touche LLP
31.1	†	Rule 13a-14(a)/15d-14(a) Certification, executed by Steven J. Newby, President, Chief Executive Officer and Director
31.2	†	Rule 13a-14(a)/15d-14(a) Certification, executed by Matthew S. Harrison, Senior Vice President and Chief Financial Officer
32.1	†	Certifications required by Rule 13a-14(b) or Rule 15d-14(b) and Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350), executed by Steven J. Newby, President, Chief Executive Officer and Director, and Matthew S. Harrison, Senior Vice President and Chief Financial Officer
101.INS	**	XBRL Instance Document (1)
101.SCH	**	XBRL Taxonomy Extension Schema
101.CAL	**	XBRL Taxonomy Extension Calculation Linkbase
101.DEF	**	XBRL Taxonomy Extension Definition Linkbase
101.LAB	**	XBRL Taxonomy Extension Label Linkbase
101.PRE	**	XBRL Taxonomy Extension Presentation Linkbase

* Management contract or compensatory plan or arrangement required to be filed as an exhibit pursuant to Item 15(b) of this report

† Certain portions have been omitted pursuant to a confidential treatment request. Omitted information has been filed separately with the Securities and Exchange Commission.

** Pursuant to Rule 406T of Regulation S-T, the Interactive Data Files on Exhibit 101 hereto are deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, are deemed not filed for purposes of Section 18 of the Securities and Exchange Act of 1934, as amended, and otherwise are not subject to liability under those sections. The financial information contained in the XBRL(eXtensible Business Reporting Language)-related documents is unaudited and unreviewed.

(1) Includes the following materials contained in this Annual Report on Form 10-K for the year ended December 31, 2012, formatted in XBRL: (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Operations, (iii) Consolidated Statements of Partners' Capital and Membership Interests, (iv) Consolidated Statements of Cash Flows, and (v) Notes to Consolidated Financial Statements.

(c) Financial Statement Schedules

Not applicable.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Summit Midstream Partners, LP
(Registrant)

March 18, 2013

By: Summit Midstream GP, LLC (its general partner)

/s/ Matthew S. Harrison
Matthew S. Harrison, Senior Vice President and Chief Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Steven J. Newby Steven J. Newby	Director, President and Chief Executive Officer (Principal Executive Officer)	March 18, 2013
/s/ Matthew S. Harrison Matthew S. Harrison	Senior Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	March 18, 2013
/s/ Thomas K. Lane Thomas K. Lane	Director	March 18, 2013
/s/ Andrew F. Makk Andrew F. Makk	Director	March 18, 2013
/s/ Curtis A. Morgan Curtis A. Morgan	Director	March 18, 2013
/s/ Jerry L. Peters Jerry L. Peters	Director	March 18, 2013
/s/ Jeffery R. Spinner Jeffery R. Spinner	Director	March 18, 2013
/s/ Susan Tomasky Susan Tomasky	Director	March 18, 2013

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
To the Board of Directors of Summit Midstream GP, LLC and the unitholders of Summit Midstream Partners, LP
Dallas, Texas

We have audited the accompanying consolidated balance sheets of Summit Midstream Partners, LP and subsidiaries (the "Partnership") as of December 31, 2012 and 2011, and the related consolidated statements of operations, partners' capital and membership interests, and cash flows for each of the three years in the period ended December 31, 2012. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Partnership is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Partnership's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Summit Midstream Partners, LP and subsidiaries as of December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 3 to the consolidated financial statements, the Partnership acquired Grand River Gathering Company, LLC on October 27, 2011.

/s/ Deloitte & Touche LLP

Dallas, Texas
March 18, 2013

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SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31,	
	2012	2011
	(Dollars in thousands)	
Assets		
Current assets:		
Cash and cash equivalents	$7,895	$15,462
Accounts receivable	33,504	27,476
Receivable from affiliate	774	—
Other assets	2,190	1,966
Total current assets	44,363	44,904
Property, plant and equipment, net	681,993	638,190
Intangible assets, net:		
Favorable gas gathering contract	19,958	21,673
Contract intangibles	229,596	242,238
Rights-of-way	35,986	32,802
Total intangible assets, net	285,540	296,713
Goodwill	45,478	45,478
Other noncurrent assets	6,137	4,979
Total assets	$1,063,511	$1,030,264
Liabilities and Partners' Capital and Membership Interests		
Current liabilities:		
Trade accounts payable	$15,817	$21,485
Deferred revenue	865	—
Ad valorem taxes payable	5,455	2,383
Other current liabilities	4,324	4,971
Total current liabilities	26,461	28,839
Promissory notes payable to Sponsors	—	202,893
Revolving credit facility	199,230	147,000
Noncurrent liability, net (Note 5)	7,420	8,944
Deferred revenue	10,899	1,770
Other noncurrent liabilities	254	—
Total liabilities	244,264	389,446
Commitments and contingencies (Note 11)		
Common limited partner capital (24,412,427 units issued and outstanding at December 31, 2012)	418,856	—
Subordinated limited partner capital (24,409,850 units issued and outstanding at December 31, 2012)	380,169	—
General partner interests (996,320 units issued and outstanding at December 31, 2012)	20,222	—
Membership interests	—	640,818
Total partners' capital and membership interests	819,247	640,818
Total liabilities and partners' capital and membership interests	$1,063,511	$1,030,264

The accompanying notes are an integral part of these consolidated financial statements.

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SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year ended December 31,		
	2012	2011	2010
	(In thousands, except per-unit and unit amounts)		
Revenues:			
Gathering services and other fees	$149,371	$91,421	$29,358
Natural gas and condensate sales	16,320	12,439	2,533
Amortization of favorable and unfavorable contracts	(192)	(308)	(215)
Total revenues	165,499	103,552	31,676
Costs and expenses:			
Operation and maintenance	51,658	29,855	9,503
General and administrative	21,357	17,476	10,035
Transaction costs	2,020	3,166	—
Depreciation and amortization	35,299	11,367	3,874
Total costs and expenses	110,334	61,864	23,412
Other income	9	12	32
Interest expense	(7,340)	(1,029)	—
Affiliated interest expense	(5,426)	(2,025)	—
Income before income taxes	42,408	38,646	8,296
Income tax expense	(682)	(695)	(124)
Net income	41,726	37,951	8,172
Net income attributable to noncontrolling interest	—	—	78
Net income attributable to SMLP	$41,726	$37,951	$8,094
Less: net income attributable to the pre-IPO period	24,112		
Net income attributable to the post-IPO period	17,614		
Less: net income attributable to general partner	352		
Net income attributable to limited partners	$17,262		
Earnings per common unit – basic	$0.35		
Earnings per common unit – diluted	$0.35		
Earnings per subordinated unit – basic and diluted	$0.35		
Weighted-average common units outstanding – basic	24,412,427		
Weighted-average common units outstanding – diluted	24,543,985		
Weighted-average subordinated units outstanding – basic and diluted	24,409,850		

The accompanying notes are an integral part of these consolidated financial statements.

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SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL AND MEMBERSHIP INTERESTS

	Partners' capital Limited partners Common	Subordinated	General partner	Membership interests	Non-controlling interest	Total
	(In thousands)					
Membership interests, January 1, 2010	$—	$—	$—	$130,268	$ 54,798	$185,066
Net income	—	—	—	8,094	78	8,172
Contributions	—	—	—	194,134	10,720	204,854
Purchase of interest in subsidiary from noncontrolling interest	—	—	—	(25,126)	(65,596)	(90,722)
Membership interests, December 31, 2010	—	—	—	307,370	—	307,370
Net income	—	—	—	37,951	—	37,951
Class B unit-based compensation	—	—	—	3,440	—	3,440
Contributions from Sponsors	—	—	—	425,000	—	425,000
Distribution of cash to Sponsor	—	—	—	(132,943)	—	(132,943)
Membership interests, December 31, 2011	—	—	—	640,818	—	640,818
Net income	8,631	8,631	352	24,112	—	41,726
SMLP unit-based compensation	269	—	—	—	—	269
Class B unit-based compensation	(186)	—	—	1,793	—	1,607
Net assets retained by the Predecessor	—	—	—	(4,417)	—	(4,417)
Contribution of net assets to SMLP	211,938	430,498	19,870	(662,306)	—	—
Issuance of common units, net of offering costs	262,382	—	—	—	—	262,382
Distribution of proceeds from offering	(64,178)	(58,960)	—	—	—	(123,138)
Partners' capital, December 31, 2012	$418,856	$380,169	$20,222	$—	$ —	$819,247

The accompanying notes are an integral part of these consolidated financial statements.

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SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year ended December 31,		
	2012	2011	2010
	(In thousands)		
Cash flows from operating activities:			
Net income	$41,726	$37,951	$8,172
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	35,299	11,367	3,874
Amortization of favorable and unfavorable contracts	192	308	215
Amortization of deferred loan costs	1,458	560	—
Pay in kind interest on promissory notes payable to Sponsors	5,426	2,025	—
SMLP unit-based compensation	269	—	—
Class B membership interest unit-based compensation expense	1,607	3,440	—
Changes in operating assets and liabilities:			
Accounts receivable	(6,028)	(17,238)	(8,865)
Receivable from affiliate	(774)	—	—
Other assets	(239)	(1,707)	125
Trade accounts payable	(2,164)	2,468	4,210
Change in deferred revenue	9,994	—	—
Ad valorem taxes payable	3,072	—	—
Other current liabilities	(604)	768	1,822
Other noncurrrent liabilities	254	—	—
Net cash provided by (used in) operating activities	89,488	39,942	9,553
Cash flows from investing activities:			
Capital expenditures	(76,698)	(78,248)	(153,719)
Acquisition of Grand River Gathering	—	(589,462)	—
Net cash provided by (used in) investing activities	(76,698)	(667,710)	(153,719)
Cash flows from financing activities:			
Proceeds from issuance of common units, net	263,125	—	—
Contributions from Sponsors	—	425,000	194,134
Distributions to Sponsors	(123,138)	(132,943)	—
Borrowings under revolving credit facility	213,000	147,000	—
Repayments under revolving credit facility	(160,770)	—	—
Deferred loan costs	(3,344)	(5,248)	—
(Repayment of) proceeds from promissory notes payable to Sponsors	(209,230)	200,000	—
Purchase of interest in subsidiary from noncontrolling interest	—	—	(90,722)
Contributions from noncontrolling interest	—	—	10,720
Net cash provided by (used in) financing activities	(20,357)	633,809	114,132
Net change in cash and cash equivalents	(7,567)	6,041	(30,034)
Cash and cash equivalents, beginning of period	15,462	9,421	39,455
Cash and cash equivalents, end of period	$7,895	$15,462	$9,421

The accompanying notes are an integral part of these consolidated financial statements.

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SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS - continued

	Year ended December 31,		
	2012	2011	2010
	(In thousands)		
Supplemental Schedule of Investing and Financing Activities:			
Cash interest paid	$8,283	$2,463	$—
Capitalized interest	(2,784)	(3,362)	—
Interest paid (net of capitalized interest)	$5,499	$(899)	$—
Cash paid for taxes	$650	$223	$10
Supplemental Disclosures of Noncash Investing and Financing Activities:			
Capital expenditures in accounts payable (period-end accruals)	$7,829	$11,332	$12,958
Pay-in-kind interest	6,337	2,893	—
Unit-based compensation	1,876	3,440	—
IPO costs incurred in 2011	743	—	—
Net assets retained by the Predecessor	4,417	—	—
Working capital acquired related to Grand River system acquisition	—	854	—

The accompanying notes are an integral part of these consolidated financial statements.

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SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND BUSINESS OPERATIONS

Organization. Summit Midstream Partners, LP ("SMLP" or the "Partnership"), a Delaware limited partnership, was formed in May 2012 and began operations in October 2012 in connection with its initial public offering ("IPO") of common limited partner units. SMLP is a growth-oriented limited partnership focused on owning and operating midstream energy infrastructure assets that are strategically located in the core producing areas of unconventional resource basins, primarily shale formations, in North America.

Summit Midstream Partners, LLC ("Summit Investments") is a Delaware limited liability company and the predecessor for accounting purposes (the "Predecessor") of SMLP. Summit Investments was formed and began operations on September 3, 2009. Through August 2011, Summit Investments was wholly owned by Energy Capital Partners II, LLC and its parallel and co-investment funds (collectively, "Energy Capital Partners"). In August 2011, Energy Capital Partners sold an interest in Summit Investments to a subsidiary of GE Energy Financial Services, Inc. ("GE Energy Financial Services", and collectively with Energy Capital Partners, the "Sponsors").

SMLP is managed and operated by the board of directors and executive officers of Summit Midstream GP, LLC (the "general partner"). Summit Investments, which is owned and controlled by Energy Capital Partners and GE Energy Financial Services, is the sole owner of our general partner and has the right to appoint the entire board of directors of our general partner, including our independent directors. SMLP's operations are conducted through, and our operating assets are owned by, various operating subsidiaries. However, neither SMLP nor its subsidiaries have any employees. The general partner has the sole responsibility for providing the personnel necessary to conduct SMLP's operations, whether through directly hiring employees or by obtaining the services of personnel employed by others, including Summit Investments. All of the personnel that conduct SMLP's business are employed by the general partner and its affiliates, but these individuals are sometimes referred to as our employees.

References to the "Company," "we," or "our," when used for dates or periods ended on or after the IPO, refer collectively to SMLP and its subsidiaries. References to the "Company," "we," or "our," when used for dates or periods ended prior to the IPO, refer collectively to Summit Investments and its subsidiaries.

Initial Public Offering. On October 3, 2012, SMLP completed its IPO and the following transactions occurred:

- Summit Investments conveyed an interest in Summit Midstream Holdings, LLC ("Summit Holdings") to our general partner as a capital contribution;
- our general partner conveyed its interest in Summit Holdings to SMLP in exchange for (i) a continuation of its 2% general partner interest in SMLP, represented by 996,320 general partner units, and (ii) SMLP incentive distribution rights, or IDRs;
- Summit Investments conveyed its remaining interest in Summit Holdings to SMLP in exchange for (i) 10,029,850 common units (net of the impact of selling 1,875,000 common units to the public for cash in connection with the exercise of the underwriters' option to purchase additional common units), representing a 20.1% limited partner interest in SMLP, (ii) 24,409,850 subordinated units, representing a 49.0% limited partner interest in SMLP, and (iii) the right to receive \$88.0 million in cash as reimbursement for certain capital expenditures made with respect to the contributed assets;
- pursuant to its long-term incentive plan, SMLP granted 5,000 common units (in the aggregate) to two of its directors and 125,000 phantom units, with distribution equivalent rights, to certain employees;
- SMLP issued 14,375,000 common units to the public (including 1,875,000 additional common units sold out of the common units originally allocated to Summit Investments) representing a 28.9% limited partner interest in SMLP; and
- SMLP used the proceeds, net of underwriters' fees, from the IPO of approximately \$269.4 million to (i) repay \$140.0 million outstanding under the revolving credit facility; (ii) make cash distributions to Summit Investments of (a) \$88.0 million to reimburse Summit Investments for certain capital expenditures it incurred with respect to assets it contributed to us and (b) \$35.1 million representing the funds received in connection with the underwriters exercising their option to purchase additional common units; and (iii) pay IPO expenses

of approximately $6.3 million.

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Upon conclusion of the above transactions, SMLP has a 100% ownership interest in Summit Holdings, which has a 100% ownership interest in both DFW Midstream Services LLC ("DFW Midstream") and Grand River Gathering, LLC ("Grand River Gathering"). The effects of the IPO and related equity transfers occurring in October 2012 are reflected in SMLP's financial statements.

Business Operations. We provide natural gas gathering and compression services pursuant to long-term, fee-based natural gas gathering agreements with our customers. Our results are driven primarily by the volumes of natural gas that we gather and compress across our systems and a significant percentage of our revenue is attributable to three producer customers and one natural gas marketer. We currently operate in two unconventional resource basins:

- the Piceance Basin, which includes the Mesaverde formation and the Mancos and Niobrara shale formations in western Colorado; and
- the Fort Worth Basin, which includes the Barnett Shale formation in north-central Texas.

Our two operating subsidiaries are DFW Midstream and Grand River Gathering. Both subsidiaries are midstream energy companies focused on the development, construction and operation of natural gas gathering systems.

In October 2011, we acquired Grand River Gathering. Grand River Gathering owns certain natural gas gathering pipeline, dehydration and compression assets located in the Piceance Basin. These assets gather production from the Mamm Creek, Orchard, and South Parachute fields in the area around Rifle, Colorado. In addition to the purchase, we have a contractual relationship with the seller related to the development of midstream infrastructure to support the seller’s emerging Mancos and Niobrara shale developments. See Note 3.

Concurrent with Summit Investments' formation in September 2009, we acquired a controlling interest in DFW Midstream. In June 2010, we purchased the remaining noncontrolling interest in DFW Midstream. DFW Midstream owns certain natural gas gathering pipeline and compression assets located in the Fort Worth Basin.

Basis of Presentation and Principles of Consolidation. We prepare our consolidated financial statements in accordance with accounting principles generally accepted in the United States of America ("GAAP"). These principles are established by the Financial Accounting Standards Board. We make estimates and assumptions that affect the reported amounts of assets and liabilities at the balance sheet dates, including fair value measurements, the reported amounts of revenue and expense, and disclosure of contingencies. Although management believes these estimates are reasonable, actual results could differ from its estimates.

For the purposes of these consolidated financial statements, SMLP's results of operations reflect the Partnership's operations subsequent to the IPO and the results of the Predecessor for the period prior to the IPO. The consolidated financial statements include the assets, liabilities, and results of operations of SMLP or the Predecessor and their wholly owned subsidiaries Summit Holdings, DFW Midstream and Grand River Gathering. All intercompany transactions among the consolidated entities have been eliminated.

Our operations are organized into a single reportable segment, the assets of which consist of natural gas gathering systems and related plant and equipment. In 2012 and 2011, the consolidated financial statements include the operations of Grand River Gathering. See Note 3.

Reclassifications. Certain reclassifications have been made to prior-year amounts to conform to current-year presentation. These reclassifications had no impact on net income or total partners' capital or membership interests.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Cash and Cash Equivalents. Cash and cash equivalents include temporary cash investments with original maturities of three months or less.

Accounts Receivable. Accounts receivable relate to gathering and other services provided to our natural gas producer customers. To the extent we doubt the collectability of our accounts receivable, we recognize an allowance for doubtful accounts. We did not experience non-payment for services during the three-year period ended December 31, 2012. As a result, we did not recognize an allowance for doubtful accounts as of December 31, 2012 and 2011.

Property, Plant, and Equipment. We record property, plant, and equipment at historical cost of construction or fair value of the assets at acquisition. We capitalize expenditures that extend the useful life of an asset or enhance its productivity or efficiency from its original design over the expected remaining period of use. For maintenance and repairs that do not add capacity or extend the useful life of an asset, we recognize expenditures as incurred. We

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capitalize project costs incurred during construction, including interest on funds borrowed to finance the construction of facilities, as construction in progress.

We base an asset's carrying value on estimates, assumptions and judgments for useful life and salvage value. We record depreciation on a straight-line basis over an asset's estimated useful life. We base our estimates for useful life on various factors including age (in the case of acquired assets), manufacturing specifications, technological advances, and historical data concerning useful lives of similar assets.

Upon sale or retirement, we remove the carrying value of an asset and its accumulated depreciation from our balance sheet and recognize the related gain or loss, if any.

Asset Retirement Obligations. We record a liability for asset retirement obligations only if and when a future asset retirement obligation with a determinable life is identified. As of December 31, 2012 and 2011, we evaluated whether any future asset retirement obligations existed. For identified asset retirement obligations, we then evaluated whether the expected retirement date of the related costs of retirement could be estimated. In performing this evaluation, we concluded that our natural gas gathering system assets have an indeterminate life because they are owned and will operate for an indeterminate future period when properly maintained. Because we did not have sufficient information to reasonably estimate the amount or timing of such obligations and we have no current plan to discontinue use of any significant assets, we did not provide for any asset retirement obligations as of December 31, 2012 or 2011.

Intangible Assets and Noncurrent Liability. Upon the acquisition of DFW Midstream, certain of our gas gathering contracts were deemed to have above-market pricing structures while another was deemed to have pricing that was below market. We have recognized the contracts that were above market at acquisition as favorable gas gathering contracts. We have recognized the contract that was deemed to be below market as a noncurrent liability. We amortize these intangibles on a units-of-production basis over the estimated useful life of the contract. We define useful life as the period over which the contract is expected to contribute directly or indirectly to our future cash flows. The related contracts have original terms ranging from 10 years to 20 years. We recognize the amortization expense associated with these intangible assets and liabilities in revenue.

For Grand River Gathering gas gathering contracts, we amortize contract intangible assets over the period of economic benefit based upon the expected revenues over the life of the contract. The useful life of these contracts ranges from 10 years to 25 years. We recognize the amortization expense associated with these intangible assets in depreciation and amortization expense.

We have right-of-way intangible assets associated with city easements and easements granted within existing rights-of-way. We amortize these intangible assets over the shorter of the contractual term of the rights-of-way or the estimated useful life of the gathering system. The contractual terms of the rights-of-way range from 20 years to 30 years. The estimated useful life of our gathering systems is 30 years. We recognize the amortization expense associated with these intangible assets in depreciation and amortization expense.

Impairment of Long-Lived Assets. We test assets for impairment when events or circumstances indicate that the carrying value of a long-lived asset may not be recoverable. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from its use and eventual disposition. If we conclude that an asset's carrying value will not be recovered through future cash flows, we recognize an impairment loss on the long-lived asset equal to the amount by which the carrying value exceeds its fair value. We determine fair value using an income approach in which we discount the asset's expected future cash flows to reflect the risk associated with achieving the underlying cash flows. During the three-year period ended December 31, 2012, we concluded that none of our long-lived assets had been impaired.

Goodwill. Goodwill represents consideration paid in excess of the fair value of the net identifiable assets acquired in a business combination. We evaluate goodwill for impairment annually on September 30. We also evaluate goodwill whenever events or circumstances indicate that it is more likely than not that the fair value of a reporting unit is less than its carrying amount.

We test goodwill for impairment using a two-step quantitative test. In the first step, we compare the fair value of the reporting unit to its carrying value, including goodwill. If the reporting unit's fair value exceeds its carrying amount, we conclude that the goodwill of the reporting unit has not been impaired and no further work is performed. If we determine that the reporting unit's carrying value exceeds its fair value, we proceed to step two. In step two, we compare the carrying value of the reporting unit to its implied fair value. If we determine that the carrying amount of a reporting unit's goodwill exceeds its implied fair value, we recognize the excess of the carrying value over the implied fair value as an impairment loss.

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Other Noncurrent Assets. Other noncurrent assets primarily consist of external costs incurred in connection with the closing of our revolving credit facility. We capitalize and then amortize deferred loan costs over the life of the revolving credit facility. We recognize amortization of deferred loan costs in interest expense. As of December 31, 2011, other noncurrent assets also included costs incurred in preparation for our IPO, however, such amounts were ultimately charged against the proceeds upon completion of the IPO.

Fair Value of Financial Instruments. The carrying amount of cash and cash equivalents, accounts receivable, and accounts payable approximates fair value due to their short-term maturities.

Commitments and Contingencies. We record accruals for loss contingencies when we determine that it is probable that a liability has been incurred and that such economic loss can be reasonably estimated. Such determinations are subject to interpretations of current facts and circumstances, forecasts of future events, and estimates of the financial impacts of such events.

Revenue Recognition. We recognize revenue when all of the following criteria are met: (i) persuasive evidence of an exchange arrangement exists, (ii) delivery has occurred or services have been rendered, (iii) the price is fixed or determinable, and (iv) collectability is reasonably assured.

We earn revenue from the natural gas gathering services that we provide to our natural gas producer customers. We recognize this revenue as gathering services and other fees revenue. We also earn revenue from the sale of physical natural gas retained from our customers and condensate retained from gathering services. We sell the natural gas that we retain from our DFW Midstream customers to offset the power expenses of the electric-driven compression on the DFW Midstream system. We record these revenue sources as natural gas and condensate sales revenue.

Certain customers reimburse us for costs we incur as outlined in the related gas gathering contract. We record costs incurred and reimbursed by our customers on a gross basis.

Our natural gas gathering agreements provide a monthly or annual minimum volume commitment ("MVC") from certain of our customers. Under these monthly or annual MVCs, our customers agree to ship a minimum volume of natural gas on our gathering systems or to pay a minimum monetary amount over certain periods during the term of the MVC. A customer must make a shortfall payment to us at the end of the contract month or year, as applicable, if its actual throughput volumes are less than its MVC for that month or year. Certain customers are entitled to utilize shortfall payments to offset gathering fees in one or more subsequent periods to the extent that such customer's throughput volumes in subsequent periods exceed its MVC for that period. These contract provisions range from 12 months to nine years.

We record customer billings for obligations under their MVCs as deferred revenue when the customer has the right to utilize shortfall payments to offset gathering fees in subsequent periods. We recognize deferred revenue under these arrangements in revenue once all contingencies or potential performance obligations associated with the related volumes have either (i) been satisfied through the gathering of future excess volumes of natural gas, or (ii) expired (or lapsed) through the passage of time pursuant to the terms of the applicable natural gas gathering agreement. We classify deferred revenue as short term for arrangements where the expiration of a customer's right to utilize shortfall payments is twelve months or less. As of December 31, 2012, our customers have been billed $11.8 million of shortfall payments, of which $0.7 million was included in accounts receivable as of December 31, 2012, attributed to arrangements that provide the customer the ability to offset gathering fees in the next one month to nine years to the extent that a customer's throughput volumes exceed its MVC.

Unit-Based Compensation. For awards of unit-based compensation, we determine a grant date fair value and recognize the related compensation expense, adjusted for expected forfeitures, in the statement of operations over the vesting period of the respective awards. See Note 9 for additional information.

Income Taxes. We are not subject to federal and state income taxes, except as noted below, because we are structured as a partnership. As a result, our unitholders or members are individually responsible for paying federal and state income taxes on their share of our taxable income.

In general, legal entities that are chartered, organized or conducting business in the state of Texas are subject to the Revised Texas Franchise Tax (the "Texas Margin Tax"). Although the bill states that the Texas Margin Tax is not an income tax, it has the characteristics of an income tax since it is determined by applying a tax rate to a tax base that considers both revenues and expenses. The tax rate is 1% for most taxable entities. The tax base is the taxable entity's margin. As outlined by statute, margin should equal the least of three calculations based on eligibility: (i) total revenue less cost of goods sold, (ii) total revenue less compensation and (iii) 70% of total revenue. Total

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revenue, costs of goods sold and compensation are all defined by statute. Our financial statements reflect provisions for these tax obligations.

Earnings Per Unit ("EPU"). Earnings per limited partner unit data is presented only for the period since the closing of SMLP’s IPO on October 3, 2012. We determined EPU by dividing the net income that was attributed, in accordance with the net income and loss allocation provisions of the partnership agreement, to the common and subordinated unitholders under the two-class method, after deducting the general partner's 2% interest in net income and any incentive distributions paid to the general partner, by the weighted-average number of common and subordinated units outstanding during the period from October 1, 2012 to December 31, 2012. Diluted earnings per limited partner unit reflects the potential dilution that could occur if securities or other agreements to issue common units, such as unit-based compensation, were exercised, settled or converted into common units. When it is determined that potential common units resulting from an award subject to performance or market conditions should be included in the diluted earnings per limited partner unit calculation, the impact is reflected by applying the treasury stock method.

EPU for periods ended prior to the IPO have not been presented because Summit Investments' members held membership interests and not units.

Comprehensive Income. Comprehensive income is the same as net income for each year in the three-year period ended December 31, 2012.

Environmental Matters. We are subject to various federal, state and local laws and regulations relating to the protection of the environment. Although we believe that we are in compliance with applicable environmental regulations, the risk of costs and liabilities are inherent in pipeline ownership and operation. We can provide no assurances that significant costs and liabilities will not be incurred by the Partnership. We are not aware of any material contingent liabilities that currently exist with respect to environmental matters.

Recent Accounting Pronouncements. Accounting standard setters frequently issue new or revised accounting rules. We review new pronouncements to determine the impact, if any, on our consolidated financial statements. There are currently no recent pronouncements that have been issued that we believe will materially affect the consolidated financial statements.

3. ACQUISITIONS

Grand River Gathering. In September 2011, we entered into a purchase and sale agreement with Encana Oil & Gas (USA) Inc., a subsidiary of Encana Corporation ("Encana"), to acquire certain natural gas gathering pipeline, dehydration and compression assets in the Piceance Basin in western Colorado (the "Grand River Transaction"). These assets gather production from the Mamm Creek, Orchard, and South Parachute fields in the area around Rifle, Colorado under long-term contracts ranging from 10 years to 25 years. The weighted-average life of these contracts was 12.8 years upon acquisition. The acquired assets included approximately 260 miles of pipeline and approximately 90,000 horsepower of compression facilities. In addition to the acquisition of Grand River Gathering, we have a contractual relationship with Encana related to the development of midstream infrastructure to support Encana’s emerging Mancos and Niobrara shale developments.

The Grand River Transaction closed on October 27, 2011, with an effective date of October 1, 2011, and was funded through an equity contribution of $410.0 million and an aggregate of $200.0 million in promissory notes from the Sponsors. We accounted for the Grand River Transaction under the acquisition method of accounting, whereby the total purchase price was allocated to Grand River Gathering's identifiable tangible and intangible assets acquired and liabilities assumed based on their fair values as of October 27, 2011. The intangible assets that were acquired are composed of gas gathering agreement contract values and right-of-way easements. Their fair values were determined based upon assumptions related to future cash flows, discount rates, asset lives, and projected capital expenditures to complete the Grand River Gathering system.

During the second quarter of 2012, we received the remaining information needed to value the acquired construction work in process and the intangible assets and then finalized its determination of the assets acquired and liabilities assumed of Grand River Gathering as well as its purchase price. As a result, we retrospectively recorded an adjustment to decrease construction work in process by $4.7 million and decrease intangible assets by $37.9 million. It also recognized deferred revenue related to minimum volume commitment payments received prior to the acquisition of Grand River Gathering. These amounts can be used by the customer to offset gathering fees in one or more subsequent periods to the extent that such customer's throughput volumes in subsequent periods exceed its minimum volume commitment. Additionally, net working capital was recorded as other current liabilities and represents the final settlement of the remaining assets acquired and liabilities assumed. These adjustments to the preliminary purchase price and the allocation to the assets acquired and liabilities assumed resulted in the recognition of goodwill totaling $45.5 million.

The final purchase price allocation has been recorded and presented on a retrospective basis. We believe that the goodwill recorded upon the finalization of the allocation represents the incremental value of future cash flow potential attributed to estimated future gathering services within the emerging Mancos and Niobrara shale developments.

The final fair values of the assets acquired and liabilities assumed as of October 27, 2011, were as follows:

	(In thousands)	
Purchase price assigned to Grand River Gathering		$590,210
Property, plant, and equipment	$295,240	
Gas gathering agreement contract intangibles	244,100	
Rights-of-way	8,016	
Total assets acquired	547,356	
Deferred revenue	1,770	
Other current liabilities	854	
Total liabilities assumed	$2,624	
Net identifiable assets acquired		544,732
Goodwill		$45,478

Unaudited Pro Forma Financial Information. The following unaudited pro forma financial information assumes that the Grand River Transaction occurred on January 1, 2010. We recorded revenue of $12.8 million and net income of $2.1 million for the two-month period from November 1, 2011 through December 31, 2011. The pro forma adjustments were derived by annualizing the actual operating results for Grand River Gathering that were recorded in 2011. Transaction costs have been adjusted to show their pro forma effect as though they had been incurred in 2010 and not incurred in 2011.

	Year ended December 31,	
	2011	2010
	(In thousands)	
Total revenue per statement of operations	$103,552	$31,676
Pro forma revenue adjustment	64,119	76,943
Pro forma total revenue	$167,671	$108,619
Net income per statement of operations	$37,951	$8,172
Pro forma net income adjustment	13,294	15,884
Pro forma transaction costs incurred adjustment	3,160	(3,160)
Pro forma net income	$54,405	$20,896

The unaudited pro forma financial information presented above is not necessarily indicative of what our financial position or results of operations would have been if the Grand River Transaction had occurred on January 1, 2010, or what SMLP’s financial position or results of operations will be for any future periods.

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4. PROPERTY, PLANT, AND EQUIPMENT, NET

Details on property, plant, and equipment, net were as follows:

	Useful lives (In years)	December 31, 2012	2011
	(Dollars in thousands)		
Gas gathering systems	30	$427,449	$335,083
Compressor stations and compression equipment	30	237,618	165,600
Construction in progress	n/a	45,919	147,616
Other	4-15	4,524	2,071
Total		715,510	650,370
Less accumulated depreciation		(33,517)	(12,180)
Property, plant, and equipment, net		$681,993	$638,190

Construction in progress is depreciated consistent with its applicable asset class once it is placed in service.

Depreciation expense related to property, plant and equipment and capitalized interest were as follows:

	Year ended December 31, 2012	2011	2010
	(In thousands)		
Depreciation expense	$21,337	$8,595	$3,355
Capitalized interest	2,784	3,362	—

5. IDENTIFIABLE INTANGIBLE ASSETS, NONCURRENT LIABILITY AND GOODWILL

Identifiable Intangible Assets and Noncurrent Liability. We accounted for the acquisitions of DFW Midstream and Grand River Gathering under the acquisition method of accounting. In connection with these acquisitions, we recognized separately identifiable intangible assets and a noncurrent liability. Identifiable intangible assets and the noncurrent liability, which are subject to amortization, were as follows:

	December 31, 2012			
	Useful lives (In years)	Gross carrying amount	Accumulated amortization	Net
	(Dollars in thousands)			
Favorable gas gathering contracts	18.7	$24,195	$(4,237)	$19,958
Contract intangibles	12.4	244,100	(14,504)	229,596
Rights-of-way	28.3	38,848	(2,862)	35,986
Total amortizable intangible assets		$307,143	$(21,603)	$285,540
Unfavorable gas gathering contract	10.0	$10,962	$(3,542)	$7,420

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	December 31, 2011			
	Useful lives (In years)	Gross carrying amount	Accumulated amortization	Net
	(Dollars in thousands)			
Favorable gas gathering contracts	18.7	$24,195	$(2,522)	$21,673
Contract intangibles	12.4	244,100	(1,862)	242,238
Rights-of-way	28.3	34,343	(1,541)	32,802
Total amortizable intangible assets		$302,638	$(5,925)	$296,713
Unfavorable gas gathering contract	10.0	$10,962	$(2,018)	$8,944

We recognized amortization expense as follows:

	Year ended December 31,		
	2012	2011	2010
	(In thousands)		
Amortization expense – favorable gas gathering contracts	$1,715	$1,718	$764
Amortization expense – contract intangibles	12,642	1,862	—
Amortization expense – rights-of-way	1,321	908	519
Amortization expense – unfavorable gas gathering contract	(1,524)	(1,410)	(549)

The estimated aggregate annual amortization of intangible assets and noncurrent liability expected to be recognized as of December 31, 2012 for each of the five succeeding fiscal years follows.

	Assets	Liabilities
	(In thousands)	
2013	$19,384	$1,441
2014	22,189	1,549
2015	25,142	1,650
2016	26,521	1,571
2017	25,891	1,438

Goodwill. We recognized goodwill of $45.5 million in connection with the Grand River Transaction and allocated it to the Grand River Gathering reporting unit (see Note 3). In September 2012, we performed our annual goodwill impairment testing and determined that the fair value of the Grand River Gathering reporting unit exceeded its carrying value resulting in no goodwill impairment. Prior to the completion of Grand River Transaction, we had no goodwill, and thus no goodwill impairments.

6. REVOLVING CREDIT FACILITY

In May 2011, we closed a senior secured revolving credit facility with total commitments of $285.0 million. Upon closing the revolving credit facility, we distributed $132.9 million to Energy Capital Partners.

In May 2012, we closed on an amendment and restatement of the revolving credit facility, which expanded our borrowing capacity to $550.0 million. Upon closing of the amendment and restatement (i) Summit Investments contributed its assets and membership interests in Grand River Gathering to Summit Holdings and (ii) Summit Holdings borrowed an additional $163.0 million under the revolving credit facility and utilized $160.0 million of the borrowings to partially repay the promissory notes payable to the Sponsors.

In July 2012, we borrowed $50.0 million under the revolving credit facility and used $49.2 million of the proceeds to repay the balance of the promissory notes payable to the Sponsors.

In October 2012, we used $140.0 million of the IPO proceeds and $5.0 million of existing cash to pay down the revolving credit facility. Prior to the IPO, aggregate repayments from existing cash totaled $15.8 million. As of December 31, 2012, the outstanding balance of the revolving credit facility was $199.2 million.

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The revolving credit facility is secured by the membership interests of Summit Holdings, DFW Midstream and Grand River Gathering and substantially all of Summit Holdings', DFW Midstream's and Grand River Gathering's assets. It is guaranteed by Summit Holdings' subsidiaries. It allows for revolving loans, letters of credit and swingline loans. The revolving credit facility matures in May 2016.

Borrowings under the revolving credit facility bear interest at the London Interbank Offered Rate ("LIBOR") plus an applicable margin or a base rate, as defined in the credit agreement. At December 31, 2012, the applicable margin under LIBOR borrowings was 2.75%, the interest rate was 2.98% and the unused portion of the revolving credit facility totaled $350.8 million (subject to a commitment fee of 0.50%).

The revolving credit agreement contains affirmative and negative covenants customary for credit facilities of its size and nature that, among other things, limit or restrict the ability to (i) incur additional debt; (ii) make investments; (iii) engage in certain mergers, consolidations, acquisitions or sales of assets; (iv) enter into swap agreements and power purchase agreements; (v) enter into leases that would cumulatively obligate payments in excess of $30.0 million over any 12-month period; and (vi) prohibits the payment of distributions by Summit Holdings if a default then exists or would result therefrom, and otherwise limits the amount of distributions Summit Holdings can make. In addition, the revolving credit facility requires Summit Holdings to maintain a ratio of consolidated trailing 12-month earnings before interest, income taxes, depreciation and amortization ("EBITDA") to net interest expense of not less than 2.5 to 1.0 (as defined in the credit agreement) and a ratio of total indebtedness to consolidated trailing 12-month EBITDA of not more than 5.0 to 1.0, or not more than 5.5 to 1.0 for up to six months following certain acquisitions (as defined in the credit agreement). As of December 31, 2012, we were in compliance with the covenants in the revolving credit facility. There were no defaults during the year ended December 31, 2012.

The revolving credit facility’s carrying value on the consolidated balance sheet is its fair value due to its floating rate.

7. PARTNERS' CAPITAL AND MEMBERSHIP INTERESTS

Partners' Capital

SMLP was formed in May 2012. Prior to its IPO on October 3, 2012, SMLP had no outstanding common or subordinated units or operations.

The principal difference between our common units and subordinated units is that in any quarter during the subordination period, holders of the subordinated units are not entitled to receive any distribution of available cash until the common units have received the minimum quarterly distribution plus any arrearages in the payment of the minimum quarterly distribution from prior quarters. Subordinated units will not accrue arrearages for unpaid quarterly distributions or quarterly distributions less than the minimum quarterly distribution. If we do not pay the minimum quarterly distribution on our common units, our common unitholders will not be entitled to receive such payments in the future except during the subordination period. To the extent we have available cash in any future quarter during the subordination period in excess of the amount necessary to pay the minimum quarterly distribution to holders of our common units, we will use this excess available cash to pay any distribution arrearages related to prior quarters before any cash distribution is made to holders of subordinated units. When the subordination period ends, all subordinated units will convert into common units on a one-for-one basis, and thereafter no common units will be entitled to arrearages.

The subordination period will end on the first business day after we have earned and paid at least (1) $1.60 (the minimum quarterly distribution on an annualized basis) on each outstanding common unit and subordinated unit and the corresponding distribution on the general partner's 2.0% interest for each of three consecutive, non-overlapping four-quarter periods ending on or after December 31, 2015 or (2) $2.40 (150.0% of the annualized minimum quarterly distribution) on each outstanding common unit and subordinated unit and the corresponding distributions on the general partner's 2.0% interest and the related distribution on the incentive distribution rights for the four-quarter period immediately preceding that date, in each case provided there are no arrearages on the common units at that time.

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A reconciliation of the number of common limited partner, subordinated limited partner and general partner units from the IPO to December 31, 2012 follows.

	Common	Subordinated	General partner
Units, beginning of period	—	—	—
Units issued to the public in connection with the IPO	14,380,000	—	—
Units issued to Summit Investments in connection with the IPO	10,029,850	24,409,850	996,320
Units issued to board of directors members	2,577	—	—
Units, end of period	24,412,427	24,409,850	996,320

Beginning with the quarter ended December 31, 2012, our partnership agreement requires that we distribute all of our available cash (as defined below) within 45 days after the end of each quarter, to unitholders of record on the applicable record date. On January 25, 2013, the board of directors of our general partner declared a distribution of $0.41 per unit for the quarterly period ended December 31, 2012. The distribution, which totaled $20.4 million, was paid on February 14, 2013 to unitholders of record at the close of business on February 7, 2013. There were no cash distributions paid by SMLP prior to 2013 other than the distribution of proceeds from the IPO.

Cash Distribution Policy

Our partnership agreement requires that we distribute all of our available cash quarterly. Our policy is to distribute to our unitholders an amount of cash each quarter that is equal to or greater than the minimum quarterly distribution stated in our partnership agreement.

Minimum Quarterly Distribution. Our partnership agreement generally requires that we make a minimum quarterly distribution to the holders of our common units and subordinated units of $0.40 per unit, or $1.60 on an annualized basis, to the extent we have sufficient cash from our operations after the establishment of cash reserves and the payment of costs and expenses, including reimbursements of expenses to our general partner. The amount of distributions paid under our policy and the decision to make any distribution is determined by our general partner, taking into consideration the terms of our partnership agreement.

Definition of Available Cash. Available cash generally means, for any quarter, all cash on hand at the end of that quarter:

- less the amount of cash reserves established by our general partner at the date of determination of available cash for that quarter to:
- provide for the proper conduct of our business (including reserves for our future capital expenditures and anticipated future debt service requirements);
- comply with applicable law, any of our debt instruments or other agreements; or
- provide funds for distributions to our unitholders and to our general partner for any one or more of the next four quarters (provided that our general partner may not establish cash reserves for distributions unless it determines that the establishment of reserves will not prevent us from distributing the minimum quarterly distribution on all common units and any cumulative arrearages on such common units for the current quarter);
- plus, if our general partner so determines, all or any portion of the cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made subsequent to the end of such quarter.

General Partner Interest and Incentive Distribution Rights. Our general partner is entitled to 2.0% of all distributions that we make prior to our liquidation. Our general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its current general partner interest. Our general partner's initial 2.0% interest in our distributions will be reduced if we issue additional units in the future and our general partner does not contribute a proportionate amount of capital to us to maintain its 2.0% general partner interest.

Our general partner also currently holds incentive distribution rights that entitle it to receive increasing percentage allocations, up to a maximum of 50.0% (as set forth in the chart below), of the cash we distribute from operating surplus in excess of $0.46 per unit per quarter. The maximum distribution of 50.0% includes distributions paid to our general partner on its 2.0% general partner interest and assumes that our general partner maintains its general

partner interest at 2.0%. The maximum distribution of 50.0% does not include any distributions that our general partner may receive on any common or subordinated units that it owns.

Percentage Allocations of Available Cash. The following table illustrates the percentage allocations of available cash between the unitholders and our general partner based on the specified target distribution levels. The amounts set forth in the column Marginal Percentage Interest in Distributions are the percentage interests of our general partner and the unitholders in any available cash we distribute up to and including the corresponding amount in the column Total Quarterly Distribution Per Unit Target Amount. The percentage interests shown for our unitholders and our general partner for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the minimum quarterly distribution. The percentage interests set forth below for our general partner include its 2.0% general partner interest and assume that our general partner has contributed any additional capital necessary to maintain its 2.0% general partner interest, our general partner has not transferred its incentive distribution rights and that there are no arrearages on common units.

	Total quarterly distribution per unit target amount	Marginal percentage interest in distributions	
		Unitholders	General partner
Minimum quarterly distribution	$0.40	98.0%	2.0%
First target distribution	$0.40 up to $0.46	98.0%	2.0%
Second target distribution	above $0.46 up to $0.50	85.0%	15.0%
Third target distribution	above $0.50 up to $0.60	75.0%	25.0%
Thereafter	above $0.60	50.0%	50.0%

Membership Interests

Energy Capital Partners and GE Energy Financial Services hold membership interests in Summit Investments. Such membership interests gives them the right to participate in distributions and to exercise the other rights or privileges available to each entity under Summit Investments' Amended and Restated Limited Liability Operating Agreement (the "Summit LLC Agreement"). In addition, certain members of Summit Investments' management hold ownership interests in the form of Class B membership interests (the "SMP Net Profits Interests") through their ownership in Summit Midstream Management, LLC.

In accordance with the Summit LLC Agreement, capital accounts are maintained for Summit Investments' members. The capital account provisions of the Summit LLC Agreement incorporate principles established for U.S. federal income tax purposes and as such are not comparable to the equity accounts reflected under GAAP in our consolidated financial statements.

The Summit LLC Agreement sets forth the calculation to be used in determining the amount and priority of cash distributions that its membership interest holders will receive. Capital contributions required under the Summit LLC Agreement are in proportion to the members' respective percentage ownership interests. The Summit LLC Agreement also contains provisions for the allocation of net earnings and losses to members. For purposes of maintaining partner capital accounts, the Summit LLC Agreement specifies that items of income and loss shall be allocated among the partners in accordance with their respective percentage interests described above.

Noncontrolling Interest in DFW Midstream. We hold all of the Class A membership interests of DFW Midstream. As the sole Class A Member, we hold units that represent membership interests, which give the holders thereof the right to participate in distributions and to exercise the other rights or privileges available to them under the DFW Midstream Amended and Restated Limited Liability Company Agreement and Contribution Agreement (collectively the "LLC Agreement"). The capital account provisions of the LLC Agreement incorporated principles established for U.S. federal income tax purposes and as such are not comparable to the equity accounts reflected under GAAP in our consolidated financial statements.

In accordance with the LLC Agreement, capital accounts are maintained for the members. Additionally, the LLC Agreement sets forth the calculation to be used in determining the amount and priority of cash distributions that Class A Members receive.

During the year ended December 31, 2010, we had several changes in membership interests related to the ownership of DFW Midstream. In June 2010, we entered into a Membership Interest Purchase Agreement with Texas

Competitive Electric Holdings Company LLC ("TCEH") whereby we purchased all of TCEH's membership interests in DFW Midstream for cash consideration of $90.7 million. Amounts reported as noncontrolling interest in 2010 relate to TCEH's ownership interests in DFW Midstream prior to the purchase. The change in our ownership

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interest in DFW Midstream as a result of the purchase decreased our membership interests by $25.1 million in 2010, as the cash consideration paid exceeded the carrying value of the noncontrolling interest at the date of purchase.
Prior to our purchase of TCEH's interest in DFW Midstream in June 2010, we held a 75% Class A membership interest and TCEH held a 25% Class A membership interest. However, distributions and allocations of income and loss were based on a sharing percentage as defined in the LLC Agreement resulting in an allocation or distribution on a basis of 70.5% for the Predecessor and 29.5% for TCEH. Capital contributions required under the LLC Agreement were made in proportion to the owners' respective percentage ownership interests. In 2010, Energy Capital Partners made cash contributions of $194.1 million to the Company that were primarily used to fund ongoing capital expenditures of DFW Midstream and purchase TCEH's noncontrolling interest. TCEH funded capital contributions of $10.7 million in 2010.

8. EARNINGS PER UNIT

The following table presents details on EPU.

	Year ended December 31, 2012 (Dollars in thousands, except per-unit amounts)
Net income attributable to the post-IPO period	$17,614
Less: net income attributable to general partner	352
Net income attributable to limited partners	$17,262
Net income attributable to common units	$8,632
Weighted-average common units outstanding – basic	24,412,427
Earnings per common unit – basic	$0.35
Weighted-average common units outstanding – diluted	24,543,985
Earnings per common unit – diluted	$0.35
Net income attributable to subordinated units	$8,630
Weighted-average subordinated units outstanding – basic and diluted	24,409,850
Earnings per subordinated unit – basic and diluted	$0.35

The weighted-average number of units used to calculate diluted earnings per common limited partner unit includes the effect of 125,000 phantom units granted in connection with the IPO and 6,558 restricted unit awards granted in connection with the exchange of certain net profits interests awards related to DFW Midstream (see Note 9).

9. UNIT-BASED COMPENSATION

Long-Term Incentive Plan. The 2012 Long-Term Incentive Plan (the "LTIP") provides for equity awards to eligible officers, employees, consultants and directors of our general partner and its affiliates, thereby linking the recipients' compensation directly to SMLP’s performance. The LTIP is administered by our general partner's board of directors, though such administration function may be delegated to a committee appointed by the board. A total of 5,000,000 common units was reserved for issuance pursuant to and in accordance with the LTIP.
The LTIP provides for the granting, from time to time, of unit-based awards, including common units, restricted units, phantom units, unit options, unit appreciation rights, distribution equivalent rights, profits interest units and other unit-based awards. Grants are made at the discretion of the board of directors or compensation committee of our general partner. The administrator of the LTIP may make grants under the LTIP that contain such terms, consistent with the LTIP, as the administrator may determine are appropriate, including vesting conditions. The administrator of

the LTIP may, in its discretion, base vesting on the grantee's completion of a period of service or upon the

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achievement of specified financial objectives or other criteria or upon a change of control (as defined in the LTIP) or as otherwise described in an award agreement. Termination of employment prior to vesting will result in forfeiture of the awards, except in limited circumstances as described in the plan documents. Units that are canceled or forfeited will be available for delivery pursuant to other awards.

In connection with the IPO and pursuant to the LTIP, the board of directors of our general partner granted 125,000 phantom units with distribution equivalent rights to certain key employees that provide services for us. A phantom unit is a notional unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit or on a deferred basis upon specified future dates or events or, in the discretion of the administrator, cash equal to the fair market value of a common unit. Distribution equivalent rights for each phantom unit provide for a lump sum cash amount equal to the accrued distributions from the grant date to be paid in cash upon the vesting date. The phantom units granted in connection with the IPO vest on the third anniversary of the consummation of the IPO. Upon vesting, awards may be settled in cash and/or common units, at the discretion of the board of directors.

The grant date fair value of the phantom unit awards, based on a per-unit fair value of $20.00, was $2.5 million. Compensation expense recognized in 2012 was approximately $0.2 million. The following table presents phantom unit activity for the year ended December 31, 2012:

	Year ended December 31, 2012
Nonvested phantom units, beginning of period	—
Phantom units granted	125,000
Phantom units vested	—
Phantom units forfeited	—
Nonvested phantom units, end of period	125,000

Upon vesting, management intends to settle the phantom unit awards with units. As of December 31, 2012, the unrecognized non-cash compensation expense related to the phantom units was $2.3 million. Incremental non-cash compensation expense will be recorded over the remaining vesting period of 2.8 years. No forfeitures were assumed in the determination of estimated compensation expense due to a lack of history.

DFW Net Profits Interests. In connection with the formation of DFW Midstream in 2009, up to 5% of DFW Midstream's total membership interests were authorized for issuance as Class B membership interests (the "DFW Net Profits Interests"). DFW Net Profits Interests participate in distributions upon time vesting and the achievement of certain distribution targets to Class A members or higher priority vested DFW Net Profits Interests. The DFW Net Profits Interests are accounted for as compensatory awards. Additional DFW Net Profits Interests were granted on April 1, 2010 and July 28, 2010. All grants vest ratably over four years and provide for accelerated vesting in certain limited circumstances, including a qualifying termination following a change in control (as defined in the underlying award agreement and LLC Agreement). As of December 31, 2012, 4.80% of DFW Net Profits Interests had been granted to certain members of management and 0.47% DFW Net Profits Interests had been forfeited.

During the year ended December 31, 2011, we determined the fair value of the DFW Net Profits Interests as of the respective grant dates for the grants made prior to that date with assistance from a third-party valuation expert. Therefore, the 2009 and 2010 awards were valued retrospectively. The DFW Net Profits Interests were valued utilizing an option pricing method, which models the Class A and Class B membership interests as call options on the underlying equity value of DFW Midstream and considers the rights and preferences of each class of equity in order to allocate a fair value to each class.

A significant input of the option pricing method is the enterprise value of DFW Midstream. We estimated the enterprise value utilizing a combination of the income and market approaches. The income approach utilized the discounted cash flow method, whereby we applied a discount rate to estimated future cash flows of DFW Midstream. Key inputs include forecasted gathering volumes, revenues and costs; unlevered equity betas of the DFW Midstream peer group; equity market risk premium; company-specific risk premium; and terminal growth rate. Under the market approach, trading multiples of the securities of publicly-traded peer companies were applied to DFW Midstream's estimated future cash flows.

Additional significant inputs used in the option pricing method include the length of holding period, discount for lack of marketability and volatility. We determined the length of holding period primarily based on our Sponsors' expectations as of the grant date. We estimated the discount for lack of marketability and volatility with assistance from a third-party valuation firm. We estimated the discount for lack of marketability using a protective put

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methodology. The protective put methodology consisted of estimating the cost to insure an investment in the DFW Net Profits Interests over the length of the holding period. Using the Black-Scholes option pricing model, we calculated the cost of a put option for the DFW Net Profits Interests as of the various grant dates. The discount for lack of marketability, in each case, is equal to the put option value divided by the value of the underlying membership interest. We estimated the expected volatility of the DFW Net Profits Interests based on the historical and implied volatilities of the securities of publicly-traded peer companies. We estimated historical volatility based on daily stock price returns over a look-back period commensurate with the length of the holding period for each grant date of DFW Net Profits Interests. We estimated implied volatility based on the average implied volatility of the publicly-traded peer companies using data from Standard & Poor's Capital IQ proprietary research tool. We based the expected volatility conclusions on consideration of both the historical and implied volatilities of the publicly-traded peer companies as of the various grant dates. The inputs we used in the option pricing method for the DFW Net Profits Interests by grant date were as follows:

	July 2010 grant		April 2010 grant		September 2009 grant	
Length of holding period restriction (In years)	3.43		3.75		4.25	
Discount for lack of marketability	35.9	%	30.9	%	34.8	%
Volatility	53.7	%	49.8	%	52.5	%

Information regarding the amount and grant date fair value of the vested and nonvested DFW Net Profits Interests were as follows:

	Year ended December 31,								
	2012			2011			2010		
	Percentage Interest		Weighted-average grant date fair value (per 1.0% of DFW Net Profits Interest)	Percentage Interest		Weighted-average grant date fair value (per 1.0% of DFW Net Profits Interest)	Percentage Interest		Weighted-average grant date fair value (per 1.0% of DFW Net Profits Interest)
	(Dollars in thousands)								
Nonvested, beginning of period	1.750	%	$ 306	2.850	%	$ 295	4.125	%	$ 220
Granted	0.000	%	$ —	0.000	%	$ —	0.300	%	$ 1,060
Vested	1.644	%	$ 256	1.100	%	$ 277	1.175	%	$ 252
Forfeited	0.069	%	$ 765	0.400	%	$ 220	0.400	%	$ 220
Nonvested, end of period	0.038	%	$ 1,650	1.750	%	$ 306	2.850	%	$ 295
Vested, end of period	4.294	%	$ 257	2.650	%	$ 258	1.550	%	$ 245

We recognize non-cash compensation expense ratably over the four-year vesting period. Non-cash compensation expense, related to the DFW Net Profits Interests, recognized within general and administrative expense was as follows:

	Year ended December 31,		
	2012	2011	2010
	(In thousands)		
Non-cash compensation expense	$688	$2,171	$—

As of December 31, 2012, the unrecognized non-cash compensation expense related to the DFW Net Profits Interests was $0.1 million. Incremental non-cash compensation expense will be recorded over the remaining expected weighted-average vesting period of 1.3 years.

For the year ended December 31, 2011, non-cash compensation expense also included approximately $0.6 million of expense related to 2010 and 2009. During the year ended December 31, 2011, the Predecessor modified the awards to remove a rate of return payout hurdle. As a result of the modification, we valued the Class B Units immediately prior to and following the modification to determine incremental compensation expense. The

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modification resulted in the immediate recognition of $1.4 million of expense attributed to the previously vested Class B Units. This amount was included in compensation expense for the year ended December 31, 2011.

In October 2012, we entered into exchange agreements with two employee holders of DFW Net Profits Interests whereby we exchanged cash for their vested DFW Net Profits Interests and SMLP restricted units for their unvested DFW Net Profits Interests. Such transactions were not material.

SMP Net Profits Interests. In connection with the formation of Summit Investments in 2009, up to 7.5% of total membership interests were authorized for issuance. SMP Net Profits Interests participate in distributions upon time vesting and the achievement of certain distribution targets to Class A members or higher priority vested SMP Net Profits Interests. The SMP Net Profits Interests are accounted for as compensatory awards. Additional SMP Net Profits Interests were granted in April 2010, April 2011, October 2011 and January 2012. All grants vest ratably over five years and provide for accelerated vesting in certain limited circumstances, including a qualifying termination following a change in control (as defined in the underlying award agreement and Summit LLC Agreement). As of December 31, 2012, 6.355% of SMP Net Profits Interests had been granted to certain members of management, and no SMP Net Profits Interests had been forfeited.

We determined the fair value of the SMP Net Profits Interests as of the respective grant dates with assistance from a third-party valuation expert. The 2012 and 2011 awards were valued contemporaneously within the year issued, and the 2009 and 2010 awards were valued retrospectively in 2011. We valued the SMP Net Profits Interests utilizing an option pricing method, which models the Class A and Class B membership interests as call options on the underlying equity value of Summit Investments and considers the rights and preferences of each class of equity in order to allocate a fair value to each class.

A significant input of the option pricing method is the enterprise value of Summit Investments. We estimated enterprise value utilizing a combination of the income and market approaches. The income approach utilized the discounted cash flow method, whereby we applied a discount rate to estimated future cash flows of Summit Investments. Key inputs include forecasted gathering volumes; revenues and costs; unlevered equity betas of Summit Investments' peer group; equity market risk premium; company-specific risk premium; and terminal growth rate. Under the market approach, we applied trading multiples of the securities of publicly-traded peer companies to Summit Investments' estimated future cash flows.

Additional significant inputs used in the option pricing method include length of holding period, discount for lack of marketability and volatility. The length of holding period was primarily determined based upon our Sponsors' expectations as of the grant date. We estimated the discount for lack of marketability and volatility with assistance from a third-party valuation firm. We estimated the discount for lack of marketability using a protective put methodology. The protective put methodology consisted of estimating the cost to insure an investment in the SMP Net Profits Interests over the length of the holding period. Using the Black-Scholes option pricing model, we calculated the cost of a put option for the SMP Net Profits Interests as of the various grant dates. The discount for lack of marketability, in each case, is equal to the put option value divided by the value of the underlying membership interest. We estimated the expected volatility of the SMP Net Profits Interests based on the historical and implied volatilities of the securities of publicly-traded peer companies. We estimated historical volatility based on daily stock price returns over a look-back period commensurate with the length of the holding period for each grant of SMP Net Profits Interests. We estimated implied volatility based on the average implied volatility of the publicly-traded peer companies using data from Standard & Poor's Capital IQ proprietary research tool. We based the expected volatility conclusions on consideration of both the historical and implied volatilities of the publicly-traded peer companies as of the various grant dates.

The inputs used in the option pricing method for the SMP Net Profits Interests by grant date were as follows:

	January 2012 grant	October 2011 grant	April 2011 grant	April 2010 grant	September 2009 grant
Length of holding period restriction (In years)	2.93	3.21	4.75	3.75	4.25
Discount for lack of marketability	24.0 %	33.1 %	29.6 %	30.9 %	34.8 %

Volatility	37.0 %	49.3 %	43.2 %	49.8 %	52.5 %

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Information regarding the amount and grant-date fair value of the vested and nonvested SMP Net Profits Interests was as follows:

	Year ended December 31,								
	2012			2011			2010		
	Percentage Interest		Weighted-average grant date fair value (per 1.0% of SMP Net Profits Interest)	Percentage Interest		Weighted-average grant date fair value (per 1.0% of SMP Net Profits Interest)	Percentage Interest		Weighted-average grant date fair value (per 1.0% of SMP Net Profits Interest)
	(Dollars in thousands)								
Nonvested, beginning of period	3.958	%	$ 1,003	2.944	%	$ 601	2.660	%	$ 386
Granted	0.500	%	$ 1,780	2.000	%	$ 1,505	1.005	%	$ 1,125
Vested	1.271	%	$ 965	0.986	%	$ 818	0.721	%	$ 541
Nonvested, end of period	3.187	%	$ 1,140	3.958	%	$ 1,003	2.944	%	$ 601
Vested, end of period	3.168	%	$ 788	1.897	%	$ 669	0.911	%	$ 508

We recognize non-cash compensation expense ratably over the five-year vesting period. Non-cash compensation expense, related to the SMP Net Profits Interests, recognized in general and administrative expense was as follows:

	Year ended December 31,		
	2012	2011	2010
	(In thousands)		
Non-cash compensation expense	$919	$1,269	$—

As of December 31, 2012, the unrecognized non-cash compensation expense related to the SMP Net Profits Interests was $3.1 million. Incremental non-cash compensation expense will be recorded by Summit Investments over the remaining expected weighted-average vesting period of 3.9 years. For the year ended December 31, 2011, non-cash compensation expense also included approximately $0.5 million of expense related to 2010 and 2009.

10. BENEFIT PLAN

We established a defined contribution benefit plan for our employees in 2009. The expense associated with this plan was approximately $0.2 million in 2012, $0.1 million in 2011, and $0.1 million in 2010.

11. COMMITMENTS AND CONTINGENCIES

Operating Leases. We lease various office space to support our operations and have determined that our leases are operating leases. Total rent expense related to operating leases, which is recognized in general and administrative expenses, was as follows:

	Year ended December 31,		
	2012	2011	2010
	(In thousands)		
Total rent expense	$724	$489	$212

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The schedule of future minimum lease payments for operating leases that had initial or remaining noncancelable lease terms in excess of one year as of December 31, 2012 was as follows:

	Operating leases (In thousands)
2013	$859
2014	787
2015	662
2016	630
2017	217

Legal Proceedings. Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, except as described below, we are not currently a party to any significant legal or governmental proceedings. In addition, we are not aware of any significant legal or governmental proceedings contemplated to be brought against us, under the various environmental protection statutes to which we are subject.

On August 21, 2012, four former DFW Midstream employees (the "Plaintiffs") who, by virtue of their Class B membership in DFW Midstream Management LLC ("DFW Management"), collectively own an aggregate 4.1% vested net profits interests in DFW Midstream, filed a claim in the Court of Chancery of the State of Delaware against Summit Investments, Summit Holdings, DFW Midstream and DFW Management (collectively, the "Defendants") seeking dissolution and wind-up of DFW Midstream and DFW Management or, in the alternative, a repurchase of the Plaintiffs' net profits interests. The Plaintiffs also seek other unspecified monetary damages, including attorneys' fees and costs. The complaint alleges that the Defendants breached (i) the DFW Midstream limited liability company agreement; (ii) compensatory arrangements with each Plaintiff; (iii) the implied covenant of good faith and fair dealing; and (iv) in the case of Summit Investments and Summit Holdings, their alleged fiduciary duties to the Plaintiffs. The complaint further alleges that the Defendants acted fraudulently with respect to the Plaintiffs. On September 28, 2012, the Defendants filed a motion to dismiss all of Plaintiffs’ claims in this matter. The court heard oral arguments on the motion to dismiss on December 12, 2012, and a decision on the motion is expected in the first half of 2013. The court has stayed discovery pending its resolution of Defendants’ motion to dismiss.

While we are unable to predict the outcome of this litigation, we believe that the Plaintiffs' allegations are meritless. We intend to vigorously defend ourselves against these allegations, and we do not believe that the dispute, even if determined adversely against us, would have a material effect on our financial position, results of operations or cash flows.

12. RELATED-PARTY TRANSACTIONS

General and Administrative Expense Allocation. Our general partner and its affiliates do not receive any management fee or other compensation in connection with the management of our business, but will be reimbursed for expenses incurred on our behalf. Under our partnership agreement, we reimburse our general partner and its affiliates for certain expenses incurred on our behalf, including, without limitation, salary, bonus, incentive compensation and other amounts paid to our general partner's employees and executive officers who perform services necessary to run our business. In addition, we reimburse our general partner for compensation, travel and entertainment expenses for the directors serving on the board of directors of our general partner and the cost of director and officer liability insurance. Our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us. Amounts paid to reimburse the general partner for these expenses were approximately $1.2 million in 2012. As of December 31, 2012, we had a $0.8 million receivable from our general partner for expenses that we paid that were not allocated to the Partnership.

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Electricity Management Services Agreement. We entered into a consulting arrangement with Equipower Resources Corp., whereby they assist DFW Midstream with managing its electricity price risk. Equipower Resources Corp. is an affiliate of our Sponsor, Energy Capital Partners. Amounts paid for such services were as follows:

	Year ended December 31,		
	2012	2011	2010
	(In thousands)		
Payments for electricity management consulting services	$204	$11	$—

Promissory Notes Payable to Sponsors. In conjunction with the Grand River Transaction, we executed $200.0 million of promissory notes, on an unsecured basis, with the Sponsors. The notes had an 8% interest rate and were scheduled to mature in October 2013. In May 2012, we borrowed $163.0 million under the revolving credit facility and used a portion of the same borrowings to prepay $160.0 million principal amount of the promissory notes payable to the Sponsors. Then in July 2012, we borrowed an additional $50.0 million under the revolving credit facility, a portion of which was used to pay the remaining $49.2 million principal amount of the promissory notes payable to Sponsors (inclusive of accrued pay-in-kind interest).

In accordance with the terms of the underlying note agreement, prior to their repayment in July 2012, we elected to make all interest payments on the note in kind. The amount of interest paid in kind and accrued to the balance of the notes for year ended December 31, 2012, was approximately $6.3 million, of which we capitalized $0.9 million of interest expense related to costs incurred on capital projects under construction.

Diligence Expenses. In the past, the Sponsors reimbursed Summit Investments for transactional due diligence expenses related to proposed transactions that were not completed. As of December 31, 2011, we had a receivable from the Sponsors of $1.3 million for similar expenses. During the year ended December 31, 2012, we were reimbursed $0.3 million, while $1.0 million was not paid.

Transition Services Agreement. We executed a transition services agreement with TCEH (an affiliate until June 2010) in September 2009. The services provided under the transition services agreement included our use of: (i) office space and computers; (ii) accounting and financial reporting services support; (iii) general support for certain health benefit matters; (iv) certain information technology support; (v) right-of-way services; and (vi) public relation services. The costs and rates charged for each service were negotiated and mutually agreed to by both parties. The termination date for each service varied and included an option to extend certain services.

	Year ended December 31,		
	2012	2011	2010
	(In thousands)		
Transition services agreement expenses	$—	$39	$137

13. CONCENTRATIONS OF RISK

Financial instruments that potentially subject us to concentrations of credit risk consist of cash and accounts receivable. We maintain our cash in bank deposit accounts that, at times, may exceed federally insured limits. We have not experienced any losses in such accounts and do not believe we are exposed to any significant risk.

Accounts receivable are primarily from natural gas producers shipping natural gas and from natural gas marketers' purchase and sale of natural gas. This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers may be similarly affected by changes in economic, industry or other conditions. We monitor the creditworthiness of our counterparties and generally require letters of credit for receivables from customers that are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated.

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Customers accounting for more than 10% of total revenues were as follows:

	Year ended December 31,		
	2012	2011	2010
Revenue:			
Customer A	20 %	34 %	50 %
Customer B	*	10 %	11 %
Customer C	12 %	17 %	20 %
Customer D	*	12 %	*
Customer E	28 %	*	*

* Customer did not exceed 10%.

Customers accounting for more than 10% of total accounts receivable were as follows:

	December 31,	
	2012	2011
Accounts receivable:		
Customer A	24 %	43 %
Customer B	*	*
Customer C	*	*
Customer D	*	*
Customer E	38 %	16 %

* Customer did not exceed 10%.

14. UNAUDITED QUARTERLY FINANCIAL DATA

Summarized information on the consolidated results of operations for each of the quarters during the two-year period ended December 31, 2012, follows.

	Quarter ended December 31, 2012	Quarter ended September 30, 2012	Quarter ended June 30, 2012	Quarter ended March 31, 2012
	(In thousands, except per-unit amounts)			
Total revenues	$48,634	$40,975	$40,107	$35,783
Net income	$17,614	$7,396	$9,129	$7,587
Less: net income attributable to general partner	352			
Net income attributable to limited partners	$17,262			
Earnings per common unit – basic	$0.35			
Earnings per common unit – diluted	$0.35			
Earnings per subordinated unit – basic and diluted	$0.35			

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	Quarter ended December 31, 2011	Quarter ended September 30, 2011	Quarter ended June 30, 2011	Quarter ended March 31, 2011
	(In thousands)			
Total revenues	$39,524	$22,160	$22,693	$19,175
Net income	$10,205	$9,807	$10,428	$7,511

Quarterly amounts may not add to the corresponding annual amounts due to rounding.