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

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 OR 15(d)
of The Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): **July 3, 2014**

Summit Midstream Partners, LP
(Exact name of registrant as specified in its charter)

Delaware	**001-35666**	**45-5200503**
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

2100 McKinney Avenue
Suite 1250
Dallas, Texas 75201
(Address of principal executive offices) (Zip Code)

Registrants' telephone number, including area code: **(214) 242-1955**

Not applicable.
(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 8.01. Other Events.

Summit Midstream Partners, LP ("SMLP" or the “Partnership”) is filing this Current Report on Form 8-K to update certain items in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2013 (the "2013 Annual Report"). On March 18, 2014, SMLP acquired all of the membership interests of Red Rock Gathering Company, LLC ("Red Rock Gathering") from Summit Midstream Partners Holdings, LLC ("SMP Holdings"), a wholly owned direct subsidiary of Summit Investments (the "Red Rock Drop Down"), and thereby acquired natural gas gathering and processing assets in the Piceance Basin in western Colorado and eastern Utah (the "Red Rock Gas Gathering system").

Prior to the Red Rock Drop Down, on October 23, 2012, Summit Investments acquired Red Rock Gathering and subsequently contributed it to SMP Holdings. As such, the Red Rock Drop Down was deemed a transaction among entities under common control and a change in reporting entity. Transfers of net assets or exchanges of membership interests between entities under common control are accounted for as if the transfer occurred at the beginning of the period, and prior periods are retrospectively adjusted to furnish comparative information similar to the pooling method. As a result, the following items of the 2013 Annual Report are being retrospectively adjusted solely to reflect the Red Rock Drop Down and the Partnership's 100% interest in the financial results of Red Rock Gathering for the period from October 23, 2012 until December 31, 2013:

- Item 1. Business;
- Item 1A. Risk Factors;
- Item 2. Properties;
- Item 6. Selected Financial Data;
- Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations;
- Item 7A. Quantitative and Qualitative Disclosures About Market Risk;
- Item 8. Financial Statements and Supplementary Data;
- Item 11. Executive Compensation;
- Exhibit 12.1 Ratio of Earnings to Fixed Charges;
- Exhibit 21.1 List of Subsidiaries; and
- Exhibit 23.1 Consent of Deloitte & Touche LLP.

These items replace the same items filed in the Partnership’s 2013 Annual Report as filed with the Securities and Exchange Commission (the "SEC") on March 10, 2014. The information in this current report on Form 8-K should be read in conjunction with the other information included (but not replaced as described above) in the 2013 Annual Report. More current information is contained in the Partnership's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2014 and the Partnership's other filings with the SEC.

Forward-Looking Statements. Investors are cautioned that certain statements contained in this current report on Form 8-K as well as in periodic press releases and certain 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 be,” “will continue,” “will likely result,” and similar expressions, or future conditional verbs such as “may,” “will,” “should,” “would,” 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 in the section entitled “Risk Factors,” attached hereto as Exhibit 99.2.

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 current report on Form 8-K 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 the cautionary statements in this paragraph. These risks and uncertainties include, among others:

- changes in general economic conditions;
- fluctuations in crude 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 and crude oil projects;
- competitive conditions in our industry and their impact on our ability to connect natural gas supplies to our gathering and processing assets or systems;
- actions or inactions taken or non-performance by third parties, including suppliers, contractors, operators, processors, transporters and customers, including the inability or failure of our shipper customers to meet their financial obligations under our gathering agreements;
- 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;
- commercial bank and capital market conditions and the potential impact of changes or disruptions in the credit and/or capital markets;
- changes in the availability and cost of capital, and the results of our financing efforts, including availability of funds in the credit and/or capital markets;
- restrictions placed on us by the agreements governing our debt instruments;
- the availability, terms and cost of downstream transportation and processing services;
- operating hazards, natural disasters, accidents, weather-related delays, casualty losses and other matters beyond our control;
- weather conditions and seasonal trends;
- timely receipt of necessary government approvals and permits, our ability to control the costs of construction, including costs of materials, labor and rights-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 litigation; and
- certain factors discussed elsewhere in this current report on Form 8-K.

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 and senior notes.

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.

Item 9.01 Financial Statements and Exhibits.

(d) Exhibits.

Exhibit Number	Description
12.1	Ratio of Earnings to Fixed Charges
21.1	List of Subsidiaries
23.1	Consent of Deloitte & Touche LLP
99.1	Updated 2013 Annual Report on Form 10-K - Item 1. Business
99.2	Updated 2013 Annual Report on Form 10-K - Item 1A. Risk Factors
99.3	Updated 2013 Annual Report on Form 10-K - Item 2. Properties
99.4	Updated 2013 Annual Report on Form 10-K - Item 6. Selected Financial Data
99.5	Updated 2013 Annual Report on Form 10-K - Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations
99.6	Updated 2013 Annual Report on Form 10-K - Item 7A. Quantitative and Qualitative Disclosures About Market Risk
99.7	Updated 2013 Annual Report on Form 10-K - Item 8. Financial Statements and Supplementary Data
99.8	Updated 2013 Annual Report on Form 10-K - Item 11. Executive Compensation
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

* 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 Current Report on Form 8-K formatted in XBRL: (i) Audited Consolidated Balance Sheets, (ii) Audited Consolidated Statements of Operations, (iii) Audited Consolidated Statements of Partners' Capital and Membership Interests, (iv) Audited Consolidated Statements of Cash Flows, and (v) Notes to Consolidated Financial Statements.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

Summit Midstream Partners, LP
(Registrant)

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

Date: July 3, 2014

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

EXHIBIT INDEX

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SUMMIT MIDSTREAM PARTNERS, LP
RATIO OF EARNINGS TO FIXED CHARGES

	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
	2013	2012	2011	2010		
	(In thousands)					
Earnings: (1)						
Income before income taxes	$ 54,033	$ 43,679	$ 38,646	$ 8,296	$ (6,599)	$ (829)
Add (deduct):						
	24,338					
Fixed charges		15,794	6,579	70	9	247
Capitalized interest	(4,705)	(2,784)	(3,362)	—	—	—
Total Earnings	$ 73,666	$ 56,689	$ 41,863	$ 8,366	$ (6,590)	$ (582)
Fixed charges: (1)						
Interest expense	$ 19,173	$ 12,766	$ 3,054	$ —	$ —	$ 247
Capitalized interest	4,705	2,784	3,362	—	—	—
Estimate of interest within rental expense	460	244	163	70	9	—
Total fixed charges	$ 24,338	$ 15,794	$ 6,579	$ 70	$ 9	$ 247
Ratio of earnings to fixed charges	3.03	3.59	6.36	119.51	(732.22) (2)	(2.36) (3)

(1) For purposes of this presentation, earnings represent income before income taxes adjusted for fixed charges and capitalized interest. Fixed charges consist of interest expensed and capitalized, amortization of deferred loan costs and an estimate of interest in rent expense.
(2) The ratio of earnings to fixed charges was less than 1:1 for the period from September 3, 2009 to December 31, 2009. In order to achieve a ratio of earnings to fixed charges of 1:1, we would have had to generate an additional $6.6 million of earnings for the period from September 3, 2009 to December 31, 2009.
(3) The ratio of earnings to fixed charges was less than 1:1 for the period from January 1, 2009 to September 3, 2009. In order to achieve a ratio of earnings to fixed charges of 1:1, we would have had to generate an additional $0.8 million of earnings for the period from January 1, 2009 to September 3, 2009.

EXHIBIT 21.1

SUMMIT MIDSTREAM PARTNERS, LP

LIST OF SUBSIDIARIES

Name	State or other jurisdiction of incorporation or organization
Summit Midstream Holdings, LLC	Delaware
Grand River Gathering, LLC	Delaware
DFW Midstream Services LLC	Delaware
Bison Midstream, LLC	Delaware
Summit Midstream Finance Corp.	Delaware
Red Rock Gathering Company, LLC	Delaware
Ridgeline Gathering Company, LLC	Delaware

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-191493 on Form S-3 and Nos. 333-184214 and 333-189684 on Form S-8 of our report dated March 10, 2014 (July 3, 2014 as to Note 1), relating to the consolidated financial statements of Summit Midstream Partners, LP and subsidiaries (the “Partnership”) (which report expresses an unqualified opinion and includes explanatory paragraphs regarding the Partnership’s acquisition of Bison Midstream and Red Rock Gathering Company, LLC which were accounted for as combinations of entities under common control and the acquisitions of the Mountaineer Midstream gathering system on June 21, 2013 and Grand River Gathering Company, LLC on October 27, 2011) appearing in this Current Report on Form 8-K dated July 3, 2014, of Summit Midstream Partners, LP.

/s/ Deloitte & Touche LLP

Dallas, Texas
July 3, 2014

Item 1. Business.

Summit Midstream Partners, LP ("SMLP") is a Delaware limited partnership that completed its initial public offering ("IPO") in October 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 but after September 3, 2009, refer collectively to Summit Investments and its subsidiaries. References to the "Initial Predecessor" refer to the predecessor of Summit Investments and its affiliates and represent our operations from January 1, 2009 to September 3, 2009.

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. The historical financial statements contained in this Form 10-K reflect (i) the assets, liabilities and operations of SMLP for dates or periods beginning on or after October 3, 2012, (ii) 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 dates or periods ending before October 3, 2012 and after September 3, 2009 and (iii) the assets, liabilities and operations of our Initial Predecessor for dates or periods ending before September 3, 2009 and beginning on or after January 1, 2009.

In March 2013, Summit Investments contributed the ownership of its SMLP common and subordinated units along with its 2% equity interests in the general partner of SMLP (including the incentive distribution rights, or "IDRs" in respect of SMLP) to Summit Midstream Partners Holdings, LLC ("SMP Holdings") in exchange for a continuing 100% interest in SMP Holdings.

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 developing, 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, treating and processing services pursuant to long-term, primarily fee-based natural gas gathering and processing agreements with our customers and counterparties. We generally refer to all of the services provided as gathering services.

Our results are driven primarily by the volumes of natural gas that we gather, treat and process across our systems. During the year ended December 31, 2013, we generated approximately 94% of our revenue, net of pass-through items, from fee-based gathering services. We currently operate in four unconventional resource basins:

- the Appalachian Basin, which includes the Marcellus Shale formation in northern West Virginia;
- the Williston Basin, which includes the Bakken and Three Forks shale formations in northwestern North Dakota;
- the Fort Worth Basin, which includes the Barnett Shale formation in north-central Texas; and
- the Piceance Basin, which includes the Mesaverde formation and the Mancos and Niobrara shale formations in western Colorado and eastern Utah.

As of December 31, 2013, our systems and the basins they serve were as follows:

- the Mountaineer Midstream system, which serves the Appalachian Basin;
- the Bison Midstream system, which serves the Williston Basin;
- the DFW Midstream system, which serves the Fort Worth Basin; and
- the Grand River system, which serves the Piceance Basin.

As of December 31, 2013, our gathering systems had approximately 2,283 miles of pipeline and 233,380 horsepower of compression. During 2013, we gathered an average of 1,138 MMcf/d of natural gas, of which approximately 66% was delivered to natural gas processing facilities.

We generate a substantial majority of our revenue under long-term, primarily fee-based natural gas gathering agreements. The fee-based nature of these agreements enhances the stability of our cash flows by limiting our direct commodity price exposure. Our customers and counterparties include affiliates and/or subsidiaries of some of the largest crude oil and natural gas producers in North America. As of December 31, 2013, we had a diverse group of customers and counterparties, including our anchor customers: Antero Resources Corp. ("Antero"), Chesapeake Energy Corporation ("Chesapeake"), Encana Corporation ("Encana"), and EOG Resources, Inc. ("EOG"). A significant percentage of our revenue is attributable to these anchor customers. For the year ended December 31, 2013, customers that accounted for 10% or more of total revenues were Chesapeake and Encana. For additional information, see Note 9 to the audited consolidated financial statements.

Substantially all of our gas gathering and processing 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 or processed by our gathering systems. Our AMIs cover more than 1.4 million acres in the aggregate and have remaining terms up to 23 years.

Certain of our gas gathering and processing agreements include minimum volume commitments ("MVCs") or minimum revenue commitments. We generally refer to MVCs and minimum revenue commitments collectively, as MVCs. An MVC contractually obligates our customers to ship or process a minimum quantity of natural gas on our systems or make payments to cover the shortfall of natural gas not shipped or processed, either on a monthly, quarterly 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 or processing agreement, whether by collecting gathering or processing fees on actual throughput or from cash payments to cover any minimum volume commitment shortfall. As of December 31, 2013, we had remaining minimum volume commitments totaling 4.2 Tcf with remaining terms that range from two years to 13 years. Our minimum volume commitments have a weighted-average remaining life of 10.3 years (assuming minimum throughput volume for the remainder of the term) and average approximately 1,230 MMcf/d through 2018.

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

Our Midstream Assets

Our midstream assets currently consist of the following four natural gas gathering systems:

- ***Mountaineer Midstream System.*** The Mountaineer Midstream system is located in the Appalachian Basin and currently serves Antero, which is targeting liquids-rich natural gas production from the Marcellus Shale formation in Harrison and Doddridge counties in West Virginia. The Mountaineer Midstream system serves as a critical inlet to the Sherwood Processing Complex, a primary destination for liquids-rich natural gas in northern West Virginia. The Sherwood Processing Complex is owned and operated by MarkWest Energy Partners, L.P. (“MarkWest”). We are currently in the process of expanding throughput capacity on the Mountaineer Midstream system from 550 MMcf/d to 1,050 MMcf/d to support Antero's current and future anticipated drilling activities in this prolific region of the Marcellus Shale Play.
- ***Bison Midstream System.*** The Bison Midstream system is located in the Williston Basin and currently serves producers that are targeting the Bakken and Three Forks shale formations in Mountrail and Burke counties in northwestern North Dakota. These formations are primarily targeted for crude oil production and producer drilling decisions are based largely on the prevailing price of crude oil. The Bison Midstream system gathers and compresses associated natural gas that exists in the crude oil production stream. Natural gas gathered on the Bison Midstream system is delivered to Aux Sable Midstream LLC's ("Aux Sable") Palermo Conditioning Plant in Palermo, North Dakota. Once conditioned, the natural gas is delivered to Aux Sable pipelines serving its 2.1 Bcf/d natural gas processing plant in Channahon, Illinois. We believe that the pace of drilling activity and thus, natural gas volume throughput on the Bison Midstream system, will primarily depend on the price of crude oil, which provides diversity of commodity price exposure for us relative to our other natural gas midstream operations.
- ***DFW Midstream System.*** The DFW Midstream system is primarily located in southeastern Tarrant County, 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. 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. We believe that the AMIs underpinning our system are substantially undeveloped compared with other areas in the Barnett Shale due to the historical lack of gathering infrastructure. Our AMIs 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.

- ***Grand River System.*** The Grand River system is located in the Piceance Basin in western Colorado and eastern Utah and currently serves producers targeting the liquids-rich Mesaverde formation as well as the emerging Mancos and Niobrara shale formations. Natural gas gathered and/or processed on the Grand River system is compressed, dehydrated, processed and/or discharged to downstream pipelines serving (i) Enterprise Products Partners L.P.'s ("Enterprise") Meeker Natural Gas Processing Plant, a 1.7 Bcf/d processing facility located in Meeker, Colorado, (ii) Williams Partners L.P.'s Northwest Pipeline system, and (iii) Kinder Morgan Energy Partners L.P.'s TransColorado Pipeline system. Processed NGLs from the Grand River system are injected into Enterprise's Mid-America Pipeline system. The Grand River system also includes a new medium-pressure gathering system to handle future natural gas production from the emerging Mancos and Niobrara shale formations. We believe that the Grand River system is optimally located for expansion to gather production from these shale formations underlying the Mesaverde formation.

Organization and Results of Operations

SMLP was formed in May 2012 in anticipation of our IPO which closed on October 3, 2012. Since the IPO, we have issued additional common units and general partner interests in connection with two acquisitions. As of December 31, 2013, SMP Holdings held 14,691,397 SMLP common units, 24,409,850 SMLP subordinated units and 1,091,453 general partner units representing a 2% general partner interest in SMLP, along with all of the IDRs issued by SMLP. For additional information, see Notes 1, 6 and 13 to the audited consolidated financial statements.

Summit Investments, which owns SMP Holdings, 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 currently conduct our natural gas gathering, treating and processing operations in the midstream sector through our four natural gas gathering systems, each of which represents one of our four operating segments. Our operating segments reflect the way in which we internally report the financial information used to make decisions and allocate resources in connection with our operations. For disclosure purposes, we have aggregated these four operating segments into one reportable segment due to their similar characteristics and how we manage our business. The assets of each of our operating segments consist of natural gas gathering systems and related property, plant and equipment.

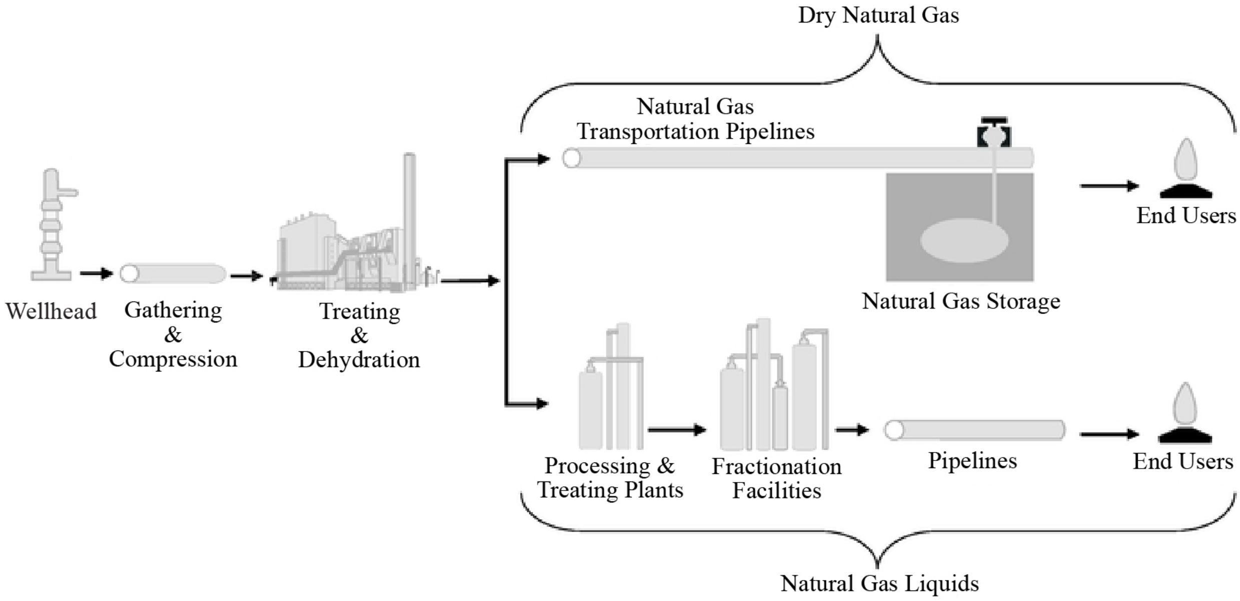
Our financial results are primarily driven by the volumes of natural gas that we gather, treat and process across our systems and our management of operation and maintenance expense. We use a variety of financial and operational metrics to analyze our performance, including among others, throughput volume, operation and maintenance expense, EBITDA, adjusted EBITDA and distributable cash flow.

For additional information on our results of operations, EBITDA, adjusted EBITDA and distributable cash flow, see Item 6. Selected Financial Data, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A"), and the audited consolidated financial statements and notes thereto included in this report.

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:



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. A substantial majority of our gas gathering agreements are fee based.

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 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 gathering, 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. The vast majority of our gas gathering agreements are firm.

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 continuing to execute 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 assets owned and operated by and under development at Summit Investments. In addition to its significant ownership interest in us, Summit Investments owns and operates, and seeks to acquire and develop, crude oil, natural gas and water-related midstream assets in service and under construction in geographic areas in which we currently operate as well as in geographic areas outside of our current areas of operations. For example, in January 2014, Summit Investments acquired an interest in two entities (collectively, “Ohio Gathering”) that own, operate and are developing significant midstream infrastructure in southeastern Ohio consisting of a liquids-rich natural gas gathering system, a dry natural gas gathering system and a condensate transportation, storage and stabilization facility in the core of the Utica shale. While Summit Investments has indicated that it intends to offer us the opportunity to acquire its interests in Ohio Gathering, it is not under any contractual obligation to do so and we are unable to predict whether or when such opportunities may arise. In its role as a midstream development vehicle for our Sponsors, we believe that Summit Investments’ development efforts mitigate potential development and cash flow timing risks associated with large-scale greenfield development projects that would otherwise be borne by us.

- ***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-based arrangements. Our midstream services are primarily provided under long-term, fee-based contracts with original terms ranging from five 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.
- ***Capitalizing on organic growth opportunities to maximize throughput on our existing systems.*** We intend to continue to leverage our management team's expertise in constructing, developing and optimizing our midstream infrastructure assets to grow our business through organic development projects. We believe that our broad and geographically diverse operating footprint provides us with a competitive advantage to pursue 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 hydrocarbon receipt points and maximize volume throughput.
- ***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, Bakken, and Marcellus shale plays currently represent our core business, we intend to diversify into other midstream services such as crude oil gathering, through both greenfield development projects and acquisitions from affiliated and non-affiliated parties. We also intend to diversify our operations into other geographic regions.
- ***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 anchor customers and commit to long-term MVCs 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 and/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 that is well-positioned for accelerated production but has limited existing midstream energy infrastructure to support such growth.

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 partnerships with large producers.*** Our assets are strategically positioned within the core areas of four established unconventional resource plays. The geologic formations in the basins served by our assets have either relatively low drilling and completion costs, highly economic production profiles, or a combination of both which incentivize producers to develop more actively than in more marginal areas.
- ***Fee-based revenues underpinned by long-term contracts with AMIs and MVCs.*** A substantial majority of our revenue for the year ended December 31, 2013 was generated under long-term, fee-based gas gathering and processing agreements. We believe that long-term, fee-based gas gathering and processing agreements enhance the stability of our cash flows by limiting our direct commodity price exposure.
- ***Capital structure and financial flexibility.*** At December 31, 2013, we had $586.0 million of total indebtedness and the unused portion of our $700.0 million amended and restated revolving credit facility totaled $414.0 million. Under the terms of the revolving credit facility, our total leverage ratio (total net indebtedness to consolidated trailing 12-month EBITDA, as defined in the credit agreement) was approximately 3.7 to 1.0 at December 31, 2013, which compares with a total leverage ratio upper limit of not more than 5.0 to 1.0, or not more than 5.5 to 1.0 for up to 270 days following certain acquisitions (as defined in the credit agreement).
- ***Experienced management team with a proven record of asset acquisition, construction, development, operation and integration expertise.*** Our senior leadership team has an average of 19

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.

- ***Relationships with large and committed financial sponsors.*** Our Sponsors, Energy Capital Partners and GE Energy Financial Services, 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 is 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 continue to benefit us as we seek to grow our business.

Our Midstream Assets

Our midstream assets currently consist of four natural gas gathering systems:

- the Mountaineer Midstream system in northern West Virginia;
- the Bison Midstream system in northwestern North Dakota;
- the DFW Midstream system in north-central Texas; and
- the Grand River system in western Colorado and eastern Utah.

We earn revenue primarily from long-term, primarily fee-based gas gathering and processing 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

A substantial majority of our gas gathering agreements contain AMIs. The AMIs generally have original terms up to 25 years and require that any production by our customers within the AMIs will be shipped on our gathering systems. Our customers do not have leases that currently cover our entire AMIs but, to the extent that our customers lease additional acreage in the future within our AMIs, natural gas produced by our customers from that leased acreage will be gathered and/or processed by our 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 AMI. 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 AMI.

Minimum Volume Commitments

Our gas gathering and processing agreements contain MVCs pursuant to which our customers guarantee to ship or process 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 five 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 or process on our 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 or processing rate multiplied by the actual throughput volumes shipped or processed.

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, quarter or year, as applicable. The amount of the shortfall payment is based on the difference between the actual throughput volume shipped or processed for the applicable period and the MVC for the applicable period, multiplied by the applicable gathering or processing 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 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 and satisfied the requirements of its aggregate MVC in 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.

Mountaineer Midstream System

In June 2013, we acquired certain natural gas gathering pipelines and compression assets located in the liquids-rich area of the Marcellus Shale Play from from an affiliate of MarkWest for $210.0 million. We refer to these assets as the Mountaineer Midstream system. The Mountaineer Midstream system benefits from its location in Doddridge and Harrison counties in West Virginia where it gathers natural gas under a long-term contract with Antero. As of December 31, 2013, the Mountaineer Midstream system had approximately 41 miles of newly constructed, high-pressure natural gas gathering pipeline and two compressor stations with 21,060 horsepower of compression. This rich-gas gathering and compression system serves as a critical inlet to MarkWest's Sherwood Processing Complex, which is currently being expanded to a capacity of 1,000 MMcf/d. As of December 31, 2013, the Mountaineer Midstream system was capable of delivering 550 MMcf/d to the Sherwood Processing Complex. The Mountaineer Midstream system includes gathering lines ranging from 12 inches to 16 inches in diameter.

The following table provides information regarding our Mountaineer Midstream system as of December 31, 2013, except as noted.

Gathering system	Approximate length (Miles)	Compression (Horsepower)	Throughput capacity (MMcf/d)	Average throughput (MMcf/d)(1)
Mountaineer Midstream	41	21,060	550	87

(1) For the year ended December 31, 2013. For the period of SMLP's ownership in 2013, average throughput was 164 MMcf/d.

In November 2013, we amended our fee-based natural gas gathering agreement with Antero whereby we will construct approximately nine miles of high-pressure, 20-inch pipeline on the Mountaineer Midstream system (the "Zinnia Loop") to accommodate higher expected volume throughput from Antero. The Zinnia Loop will increase Mountaineer Midstream system’s throughput capacity from 550 MMcf/d to 1,050 MMcf/d. The project is underpinned by a new, 12-year, minimum revenue commitment from Antero, which extends the original term of the contract through 2026. We have commenced work on the project and expect to commission it in 2014. With this expansion, the Mountaineer Midstream system will enhance its strategic position as a primary source of natural gas deliveries to the Sherwood Processing Complex.

Bison Midstream System

In June 2013, we acquired certain associated natural gas gathering pipeline, dehydration and compression assets in the Williston Basin in northwestern North Dakota from SMP Holdings for $248.9 million. We refer to these assets as the Bison Midstream system. The Bison Midstream system gathers natural gas produced from the Bakken and Three Forks shale formations under long-term, primarily fee-based, contracts ranging from five years to 15 years. Since its acquisition, we have expanded the Bison Midstream system by adding pipeline and installing incremental compression horsepower. This system, which is located in Mountrail and Burke counties, comprised approximately 343 miles of low- and high-pressure pipeline and six compressor stations with approximately 7,800 horsepower of compression as of December 31, 2013 and includes gathering lines ranging from 3 inches to 10 inches in diameter. Natural gas gathered on the Bison Midstream system is delivered to Aux Sable’s Palermo Conditioning Plant in Palermo, North Dakota. Once conditioned, the natural gas is delivered on Aux Sable pipelines to its 2.1 Bcf/d natural gas processing plant in Channahon, Illinois.

The Bison Midstream system benefits from its location in Mountrail and Burke counties in North Dakota. Total throughput capacity on the system is in the process of being expanded to 30 MMcf/d with the installation of new compression which is expected to be completed by the end of 2014. Volume throughput on the Bison Midstream system is underpinned by MVCs from its anchor customer, EOG.

The following table provides information regarding our Bison Midstream system as of December 31, 2013, except as noted.

Gathering system	Approximate length (Miles)	Compression (Horsepower)	Throughput capacity (MMcf/d)	Average throughput (MMcf/d)(1)	Approximate areas of mutual interest (Acres)	Remaining MVCs (Bcf)
Bison Midstream	343	7,800	24	14	676,500	29

(1) For the year ended December 31, 2013. For the period of SMLP's ownership in 2013, average throughput was 16 MMcf/d.

In addition to its gas gathering agreement with EOG, the Bison Midstream system is also supported by other fee-based and percent-of-proceeds gas gathering agreements with Cornerstone Natural Resources LLC, Hess Corporation, Hunt Oil Company, Statoil ASA and Oasis Petroleum Inc. As of December 31, 2013, these gas gathering agreements had remaining MVCs totaling approximately 29 Bcf and, through 2018, average approximately 14 MMcf/d. In addition, these gas gathering agreements have AMIs that cover approximately 676,500 net acres through 2027.

We continue to develop the Bison Midstream system to extend our gathering reach, diversify our customer base, increase our receipt points and maximize throughput. Since our acquisition, we have expanded and increased system reliability by adding pipeline, continuing to connect additional pad sites located within our areas of mutual interest, and installing additional compression. For the year ended December 31, 2013, the Bison Midstream system had average throughput of approximately 14 MMcf/d.

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 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, 2013, the DFW Midstream system had approximately 119 miles of pipeline and three compressor stations with approximately 56,100 horsepower of compression. 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 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.

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 December 2013, this area contains the most prolific wells in the Barnett Shale. For example, the two largest and four of the five largest wells drilled in the Barnett Shale (based on peak month average daily rates) 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.

The following table provides information regarding our DFW Midstream system as of December 31, 2013, except as noted.

Gathering system	Approximate length (Miles)	Compression (Horsepower)	Throughput capacity (MMcf/d)	Average throughput (MMcf/d)(1)	Approximate areas of mutual interest (Acres)	Remaining MVCs (Bcf)
DFW Midstream	119	56,100	450	391	107,300	263

(1) For the year ended December 31, 2013.

In September 2009, we entered into a long-term, fee-based 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. In addition to Chesapeake, the DFW Midstream system is underpinned by seven other long-term, fee-based gas gathering agreements with Atlas Energy L.P., Beacon E&P Company, LLC, EnerVest, Ltd., EOG, Exxon Mobil Corporation, TOTAL, S.A. and Vantage Energy, LLC. As of December 31, 2013, DFW Midstream's gas gathering agreements had remaining MVCs totaling approximately 263 Bcf and, through 2018, average approximately 141 MMcf/d. In addition, these gas gathering agreements have areas of mutual interest that cover approximately 107,300 acres through 2030.

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 gathering system and as such would not require significant additional capital expenditures. 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. We also recently constructed a 150 gallon per minute natural gas treating facility that will enable us to provide treating services that would otherwise be provided to our customers by third parties. The natural gas treating facility was commissioned in February 2014. 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. For the year ended December 31, 2013, the DFW Midstream system had average throughput of approximately 391 MMcf/d.

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 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.

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. These assets gather natural gas from the Mesaverde formation and the Mancos and Niobrara shale formations located within the Piceance Basin. They are primarily located in Garfield County, the largest natural gas producing county in Colorado and are 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.

In March 2014, we acquired 100% of Summit Investments' interests in Red Rock Gathering Company, LLC ("Red Rock Gathering") in exchange for total cash consideration of $305.0 million, subject to customary working capital adjustments. Summit Investments acquired the natural gas gathering pipeline, dehydration, compression and processing assets in the Piceance Basin in western Colorado and eastern Utah that comprise the Red Rock Gathering system from Energy Transfer Partners in September 2012 for $206.7 million. These assets gather and process natural gas from the Mesaverde formation and the Mancos and Niobrara shale formations located within the Piceance Basin. They are primarily located in Rio Blanco and Mesa counties in Colorado and Uintah and Grand counties in Utah.

We refer to the assets that we acquired in October 2011 and March 2014 collectively as the Grand River system. Natural gas gathered and/or processed on the Grand River system is compressed, dehydrated, processed and/or discharged to downstream pipelines serving (i) Enterprise's Meeker Natural Gas Processing Plant, a 1.7 Bcf/d processing facility located in Meeker, Colorado, (ii) Williams Partners L.P.'s Northwest Pipeline system, and (iii)

Kinder Morgan Energy Partners L.P.'s TransColorado Pipeline system. Processed NGLs from the Grand River system are injected into Enterprise's Mid-America Pipeline system. As of December 31, 2013, the Grand River system comprised approximately 1,780 miles of pipeline, 148,420 horsepower of compression and had aggregate throughput capacity of 1,125 MMcf/d.

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. 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 three 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 expect to continue to pursue additional volumes on the low-pressure system to more fully utilize the existing throughput capacity.

The following table provides information regarding our Grand River system as of December 31, 2013, except as noted.

Gathering system	Approximate length (Miles)	Compression (Horsepower)	Throughput capacity (MMcf/d)	Average throughput (MMcf/d) (1)	Approximate areas of mutual interest (Acres)	Remaining MVCs (Bcf)
Mamm Creek	208	60,180	600	386	174,000	978
South Parachute	43	12,168	75	71	17,000	—
Orchard	50	25,152	210	41	39,000	825
Rifle	126	25,000	171	99	180,480	490
Other	1,353	25,920	69	49	260,480	81
Total Grand River system	1,780	148,420	1,125	646	670,960	2,374

(1) For the year ended December 31, 2013.

In October 2011, we entered into a long-term, fee-based gas gathering agreement with Encana as our anchor customer that included a 25-year area of mutual interest covering approximately 187,000 acres and a 15-year MVC totaling approximately 1,558 Bcf. In conjunction with Summit Investments' acquisition of Red Rock Gathering, we assumed fee-based agreements with Black Hills Exploration and Production, Inc. ("Black Hills") and a subsidiary of WPX Energy, Inc ("WPX"). Both agreements include long-term acreage dedications and collectively provide more than 350 Bcf of MVCs. In connection with the Black Hills agreement, we agreed to construct a processing plant and related gas gathering infrastructure in the DeBeque, Colorado area to support Black Hills' future development of its liquids-rich Mancos and Niobrara acreage. In connection with the WPX agreement, we agreed to expand our existing gathering and compression services by constructing gas gathering infrastructure to gather new WPX production in the Rifle, Colorado area. The processing plant in DeBeque was commissioned in March 2014 and the WPX project will be developed and commissioned over the next few years. In addition to Encana, WPX and Black Hills, the Grand River system is underpinned by other long-term, fee-based gas gathering and compression agreements with Bill Barrett Corporation and Ursa Resources Group II LLC.

The Grand River system's gas gathering and processing agreements include MVCs with original terms ranging from five to 15 years and areas of mutual interest with original terms up to 25 years. We gather natural gas from these primary and other customers at the wellhead and receive natural gas at central receipt points along the Grand River system. As of December 31, 2013, Grand River's gas gathering and/or processing agreements had remaining MVCs totaling approximately 2,374 Bcf and areas of mutual interest that cover approximately 670,960 acres through 2036. Through 2018, the remaining MVCs are expected to average approximately 713 MMcf/d. For the year ended December 31, 2013, the Grand River system gathered an average of approximately 646 MMcf/d.

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. 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.

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 $13.0 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, 2013, Energy Capital Partners and its affiliated funds had 24 investment platforms with investments in the power generation, midstream oil and gas, electric transmission, energy equipment and services, environmental infrastructure and other energy related 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, 2013, GE Energy Financial Services held approximately $18 billion in energy assets worldwide. GE Energy Financial Services has invested over $2.0 billion in midstream-related assets.

Summit Investments, which owns and controls our general partner, has an inventory of midstream assets comprising more than $2.0 billion of previous acquisitions and current and future development projects. In addition to its midstream assets located in the Piceance Basin in Colorado, the Uinta Basin in Utah and the Williston Basin in North Dakota, Summit Investments has also acquired an interest in two entities that own, operate and are developing significant midstream infrastructure in southeastern Ohio consisting of a liquids-rich natural gas gathering system, a dry natural gas gathering system and a condensate transportation, storage and stabilization facility in the core of the Utica Shale. All of these midstream assets offer opportunities for customer and service offering diversification into crude oil and water gathering and liquids rich gas processing. Furthermore, we believe they present an opportunity for our further geographic diversification due to their presence in the Piceance and Uinta basins in Colorado and Utah, the Bakken Shale Play in North Dakota, the DJ Niobrara Basin in Colorado and the Utica Shale Play in Ohio. While these assets have not been contributed to SMLP and SMP Holdings is not obligated to sell these assets to SMLP, we believe they may represent a future opportunity for execution of our business strategy.

Competition

We compete with 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. 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 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, nor have we been required to file a tariff in West Virginia or North Dakota for our operations in those states, although regulatory authorities in North Dakota have recently issued new rules requiring the submission of shape files to identify the location of underground gathering pipelines. The states in which we operate 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 in Texas, Colorado, North Dakota, and West Virginia generally have not initiated investigations of the rates or practices of gathering systems or intrastate pipelines in the absence of a complaint. State regulation of intrastate pipelines continues to evolve and may become more stringent in the future.

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 (the "CFTC") 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 CFTC has adopted anti-market manipulation regulations that prohibit fraud and price manipulation in the commodity and futures markets. The CFTC 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 that are identical to or more restrictive than 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;
- 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. The notice also solicited comments on changes to the definition of gathering pipelines, which could subject many currently exempted pipelines to the PHMSA regulations. 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 stringent requirements, resulting in 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 and future regulations.

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

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 we believe that the previous operators 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 to obtain and maintain operating permits and approvals for air pollutant emitting sources.

In April 2012, the EPA finalized rules that establish new air emission reporting, monitoring, and control requirements for oil and natural gas production and natural gas processing operations. Specifically, the EPA's rule package included New Source Performance Standards ("NSPS") to address emissions of sulfur dioxide and volatile organic compounds ("VOCs") from a number of sources that were previously not regulated in the oil and gas industry. Additionally, the EPA revised several existing regulations in this rulemaking effort 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, pneumatic controllers, 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 VOC emitting tanks at initial startup. 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 will impact our upstream 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.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce emissions of GHGs in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs.

In November 2013, the Colorado Department of Public Health and Environmental (CDPHE) proposed a number of changes to existing statewide air emission regulations. This rulemaking was in response to the newly issued Federal regulations described above, and the State of Colorado’s obligation to either adopt the Federal Standards, or implement statewide standards which are as stringent or more stringent than the Federal standards. Colorado has proposed changes to its statewide regulations in an effort to reduce emissions of VOCs and other hazardous air pollutants from the production and processing sectors, as well as to comply with the newly issued NSPS. The proposed regulatory language will have significant impacts on both upstream and midstream operators throughout the state of Colorado. Notably, the rule, if adopted, will require all operators to implement a leak detection and repair program at all of their oil and gas facilities. Historically these leak detection and repair requirements have only applied to the natural gas processing sector and not upstream and/or gathering system operations. Summit expects to incur additional operating costs to comply with the revised regulations in Colorado.

The adoption of any legislation or regulations that requires reporting of greenhouse gases (“GHGs”) or otherwise restricts emissions of GHGs from our equipment and operations could require us to incur significant added costs to reduce emissions of GHGs or could adversely affect demand for the natural gas and NGLs we gather and process or fractionate. Moreover, if Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on operations and reduce demand for refined products, which could adversely affect the services we provide. Finally, some scientists have concluded that increasing concentrations of GHGs in the Earth’s atmosphere may produce climate change that could have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events; if such effects were to occur, they could have an adverse effect on our operations.

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 our compression and processing facilities, as required. These permits require us to control 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 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.

The federal government is currently undertaking several studies of hydraulic fracturing's potential impacts. The EPA released 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 final rule has not yet been published, but is expected sometime in 2014. 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 Texas, Colorado, North Dakota, and West Virginia, 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, including 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. In December 2009, the EPA published its findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA has adopted regulations under the Clean Air Act that, among other things, establish GHG emission limits from motor vehicles as well as establish Prevention of Significant Deterioration ("PSD") construction and Title V operating permit reviews for certain large stationary sources that are potential major sources of GHG emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards that will be established by the states or, in some cases, by the EPA on a case-by-case basis. In October 2013, the U.S. Supreme Court agreed to hear a lawsuit challenging whether the EPA permissibly determined that the regulation of GHG emissions from new motor vehicles triggered permitting requirements under the Clean Air Act for stationary sources that emit GHGs, with a decision expected in 2014.

In addition, in September 2009, the EPA issued a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emitting 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 our assets that have greenhouse gas emissions above the reporting thresholds. The EPA continues to consider additional climate change requirements for the energy industry. 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 our operations.

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, but these individuals are sometimes referred to as our employees. The officers of our general partner manage our operations and activities. As of December 31, 2013, Summit Investments employed 242 people who provide direct, full-time support to our operations. None of our employees are covered by collective bargaining agreements, 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, NE, Washington, D.C. 20549 or by calling 1-800-SEC-0330. These filings are also available through the SEC's website, *www.sec.gov*. SMLP's press releases and recent investor presentations are also available on SMLP's website.

Item 1A. Risk Factors.

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 $21.9 million per quarter, or $87.8 million per year (based on units outstanding, as of December 31, 2013, including nonvested LTIP awards). We may not have 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, treat and process;
- 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, crude oil, 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;
- weather conditions and seasonal trends;
- 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, crude oil, natural gas and NGLs, 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.

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, treating and processing services in four unconventional resource basins: (i) the Appalachian Basin, which includes the Marcellus Shale formation in northern West Virginia; (ii) the Williston Basin, which includes the Bakken and Three Forks shale formations in northwestern North Dakota; (iii) the Fort Worth Basin, which includes the Barnett Shale formation in north-central Texas; and (iv) the Piceance Basin, which includes the Mesaverde formation and the Mancos and Niobrara shale formations in western Colorado and eastern Utah. 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 industry 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.

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 weaknesses 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. The price of natural gas has been at historically low levels for an extended period of time. 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 generally 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. Until the supply overhang has been reduced and the economy sees more robust growth, we believe that 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 certain of our areas of operation, including the Fort Worth and Piceance basins. Due to the extended period of historically low natural gas prices, certain of our customers in those basins have announced their intent to reduce capital expenditures for dry gas drilling activities. For instance, in December 2013, Encana, one of our largest producers in the Piceance Basin, announced that they would cease drilling any additional natural gas wells in the Piceance Basin in 2014 in connection with their stated strategy to deploy additional capital resources to oil and liquids-rich basins.

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 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 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 and process 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 ability to obtain new 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 crude oil, natural gas and NGLs;
- demand for crude 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 crude oil and natural gas reserves. Drilling and production activity generally decreases as commodity prices decrease. In general terms, the prices of crude oil, natural gas, 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 crude oil, natural gas, LNG and other commodities.

Because of these factors, even if new crude oil or 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.

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, treating and processing 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.

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 and processing 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 and processing agreements contain provisions that can reduce the cash flow stability that the agreements were designed to achieve.

Our gas gathering and processing 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 to our processing plants 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 and processing agreements also include an aggregate minimum volume commitment, which is a total amount of natural gas that the customer must flow on our gathering system or send to our processing plants (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, quarter or year, as applicable. The amount of the shortfall payment is based on the difference between the actual throughput volume shipped or processed for the applicable period and the minimum volume commitment for the applicable period, multiplied by the applicable 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).
- 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 had 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 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

would receive lower gathering fees in a particular contract period 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 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. Crude oil and natural gas reserve engineering requires subjective estimates of underground accumulations of crude oil and natural gas and assumptions concerning future crude 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 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 natural 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 natural gas 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 and process 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, treat and process 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 and/or processing services to our markets;
- the macroeconomic factors affecting natural gas gathering and processing 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. For example, in the third quarter of 2013, volume throughput for the Mountaineer Midstream system was impacted by temporary processing capacity curtailments resulting from a line break on one of MarkWest’s NGL pipelines which forced the Mountaineer Midstream system to curtail its natural gas deliveries to MarkWest's Sherwood Processing Plant. 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 and process, 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, and we have owned Bison Midstream and Mountaineer Midstream for less than a full year. 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 all of our assets in the last five years, and we have owned Bison Midstream and Mountaineer for less than one year. As a result, our executive management team has a relatively limited history of operating our assets. There may be historical occurrences or latent issues regarding our pipeline systems of which our executive management team may be unaware 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 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, treating and processing 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.

Crude oil and natural gas activities in certain areas of our gathering systems may be adversely affected by seasonal weather conditions which in turn could negatively impact the operations of our gathering, treating and processing facilities and our construction of additional facilities.

Extended periods of below freezing weather and unseasonably wet weather conditions across our systems, especially in North Dakota and West Virginia, can be severe and can adversely affect oil and gas operations due to the potential shut-in of producing wells or decreased drilling activities. The result of these types of interruptions could result in a decrease in the volumes of natural gas supplied to our gathering systems. Further, delays and shutdowns caused by severe weather during the winter months may have a material negative impact on the continuous operations of our gathering systems, including interruptions in service. These types of interruptions could negatively impact our ability to meet contractual obligations to our customers and thereby give rise to certain termination rights and releases of dedicated acreage. Any resulting terminations or releases could materially affect our business and results of operations.

Interruptions in operations at any of our facilities may adversely affect our operations and cash flows available for distribution to our unitholders.

Our operations depend upon the infrastructure that we have developed and constructed. Any significant interruption at any of our gathering, treating or processing facilities, or in our ability to gather, treat or process natural gas or NGLs, would adversely affect our operations and cash flows available for distribution to our unitholders.

Operations at our facilities could be partially or completely shut down, temporarily or permanently, as the result of circumstances not within our control, such as:

- unscheduled turnarounds or catastrophic events at our physical plants or pipeline facilities;
- restrictions imposed by governmental authorities or court proceedings;
- labor difficulties that result in a work stoppage or slowdown;
- a disruption in the supply of resources necessary to operate our midstream facilities;
- damage to our facilities resulting from natural gas or NGLs that do not comply with applicable specifications; and
- inadequate transportation or market access to support production volumes, including lack of availability of pipeline capacity.

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, treating and processing 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 our 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.

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 SMP Holdings 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 SMP Holdings 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) 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, including the acquisitions of Red Rock Gathering, Bison Midstream and Mountaineer Midstream, 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;
- customer or key employee losses at the acquired businesses; and
- production declines higher than anticipated and facilities being properly constructed.

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.

We may fail to successfully integrate Red Rock Gathering, Bison Midstream and Mountaineer Midstream into our existing business in a timely manner, which could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders, or fail to realize all of the expected benefits of the acquisitions, which could negatively impact our future results of operations.

Integration of the assets acquired in the Red Rock Gathering, Bison Midstream and Mountaineer Midstream acquisitions with our existing business has been, and will be, a complex, time-consuming and costly process, particularly given that the acquired assets significantly increased our size and diversified the geographic areas in which we operate. A failure to successfully integrate the acquired assets with our existing business in a timely manner may have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

If any of the risks described in the risk factor immediately above or unanticipated liabilities or costs were to materialize with respect to the Bison Midstream or Mountaineer Midstream acquisitions, or if the acquired assets were to perform at levels below the forecasts we used to evaluate them, then the anticipated benefits from the acquisition may not be fully realized, if at all, and our future results of operations could be negatively impacted.

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. For example, in November 2013, we announced an amendment of our natural gas gathering agreement with Antero Resources Corporation (“Antero”) related to the development of a new high-pressure pipeline looping project designed to expand throughput capacity at Mountaineer Midstream to 1,050 MMcf/d (the “Zinnia Loop”). The Zinnia Loop is being constructed to support an anticipated increase in throughput related to Antero’s drilling program in the Marcellus Shale formation. 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 the Zinnia Loop project to support Antero’s drilling program in the Marcellus Shale formation, 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 or modifications to our existing gathering, treating and processing assets and the construction of new midstream assets may require us to obtain new rights-of-way or federal and state environmental or other authorizations. The approval process for gathering, treating and processing activities has become increasingly challenging, due in part to state and local concerns related to unregulated exploration and production and gathering, treating and processing 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 and processing 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 and processing 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. 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 revolving credit facility.

We plan 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, treat and process new natural gas production from 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 to our unitholders.

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 a 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.

Debt we incur in the future may limit our flexibility to obtain financing and to pursue other business opportunities.

At December 31, 2013, we had $586.0 million of total indebtedness and the unused portion of our $700.0 million amended and restated revolving credit facility totaled $414.0 million. 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 and senior notes indenture could materially adversely affect our business, financial condition, results of operations, ability to make cash distributions to unitholders and value of our common units.

We are dependent upon the earnings and cash flow generated by our operations in order to meet our debt service obligations and to make cash distributions to our unitholders. The operating and financial restrictions and covenants in our amended and restated revolving credit facility, our indenture and any future financing agreements could restrict our ability to finance future operations or capital needs or to expand or pursue our business activities, which may, in turn, limit our ability to make cash distributions to our unitholders. For example, our amended and restated revolving credit facility and indenture restrict 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 and indenture also contain 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.

The provisions of our amended and restated revolving credit facility and indenture 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 or indenture could result in a default or an event of default that could enable our lenders or noteholders to declare the outstanding principal of that debt, together with accrued and unpaid interest, to be immediately due and payable. If we were unable to repay the accelerated amounts, the lenders under our amended and restated revolving credit facility could proceed against the collateral granted to them to secure such debt. 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. The amended and restated revolving credit facility also has cross default provisions that apply to any other indebtedness we may have and the indentures have cross default provisions that apply to certain other indebtedness.

A portion of our revenues are exposed to changes in crude 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, primarily fee-based gas gathering and processing agreements under which we are paid based on the volumes of natural gas that we gather and/or process 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 will seek to enter into similar fee-based contracts with new customers in the future, our efforts to obtain such contractual terms may not be successful or the local market for our services may not support fee-based gas gathering and processing agreements. For example, in connection with our acquisition of Red Rock Gathering and Bison Midstream, we have percent-of-proceeds and keep-whole contracts with certain customers and we may, in the future, enter into additional percent-of-proceeds and keep-whole 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. Under these keep-whole arrangements, our principal cost is delivering dry gas of an equivalent BTU content to replace BTUs extracted from the gas stream in the form of NGLs or consumed as fuel during processing. Generally, the spreads between the NGL product sales price and the purchase price of natural gas with an equivalent BTU content are positive under these arrangements. However, in the event natural gas becomes more expensive on a BTU equivalent basis than NGL products, the cost of keeping the producer “whole” could result in lower, and in some cases, negative, net operating margins.

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 retain 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 crude 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 crude 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 regulation. Numerous federal, state and local departments and agencies are authorized by statute to issue, and have issued, rules, regulations and interpretations binding upon participants in the natural gas industry. The regulation of our activities and the natural gas industry generally frequently changes as the activities of the industry often are reviewed by legislators and regulators. In 2014, the North Dakota Industrial Commission will begin to oversee the integrity and location of underground gathering pipelines that are not monitored by other state or federal agencies. The U.S. Department of Transportation (DOT) is considering rule changes that would extend pipeline safety regulation to previously unregulated rural gathering systems and increase safety requirements for other pipelines as well. Penalties for violating federal safety standards have recently increased. In addition, the adoption of proposals for more stringent legislation, 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. Regulatory 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. 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' crude oil and 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 crude oil and natural 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 Bureau of Land Management issued a proposed rule to regulate hydraulic fracturing on public and Indian lands. The proposed rule would require public disclosure of chemicals used in hydraulic fracturing on federal and Indian lands, confirmation that wells used in fracturing operations meet appropriate construction standards, and development of appropriate plans for managing flowback water that returns to the surface. The final rule has not yet been published, but is expected sometime in 2014. In addition, the EPA has commenced a multi-year study of the potential environmental impacts of hydraulic fracturing, and a draft report of the findings is 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.

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, Colorado, North Dakota, Utah and West Virginia, 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. 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 crude 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 crude 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 (the "CFTC") is directed under the Commodity Exchange Act, to prevent price manipulation in the commodity, futures and swaps markets, including the energy 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 CFTC has adopted additional anti-market manipulation regulations that prohibit fraud and price manipulation in the commodity, futures and swaps markets. The CFTC also has statutory authority to seek civil penalties of up to the greater of $1,000,000 per violation or triple the monetary gain to the violator for each violation of the anti-market manipulation provisions 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 is 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, Congress or the courts. If our gas gathering operations become subject to FERC jurisdiction over interstate service under the NGA or the Natural Gas Policy Act of 1978, or NGPA, 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. In addition, if any of our facilities were found to have provided services or otherwise operated in violation of the NGA or NGPA, this could result in the imposition of civil penalties, as well as a requirement to disgorge charges collected for such services in excess of the rate established by the FERC.

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, treat and process. 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, treat and process. Many states have adopted complaint-based regulation of gathering, treating and processing 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, treating and processing, including state regulation of production rates, maximum daily production allowable from natural 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 environmental laws and regulations that may expose us to significant costs and liabilities.

Our natural gas gathering, treating and processing 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 on which certain of our facilities are located, 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 that are identical to or more restrictive than existing U.S. DOT 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 Midstream system is located. While the majority of our pipelines meet the U.S. DOT definition of gathering lines and are thus exempt from the PHMSA's integrity management requirements, we also operate a limited number of pipelines 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.

The PHMSA is considering changes to its safety regulations, including whether to revise the integrity management requirements and whether to change the definition of gathering pipelines, which could subject many currently exempted pipelines to PHMSA regulations and could have a material adverse effect on our operations and costs of transportation services. The PHMSA has also 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.

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 emitting sources in the United States beginning in 2011 for emissions occurring in 2010. In May 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 November 2010, the EPA issued a final rule expanding its existing greenhouse gas emissions reporting rule to include onshore and offshore oil and natural gas systems. These rules require data collection beginning in 2011 and reporting beginning in September 2012 and require that we report our greenhouse gas emissions for our assets that have greenhouse gas emissions above the reporting thresholds. As a result of this continued regulatory focus, further greenhouse gas regulation of the oil and gas industry remains a possibility.

On May 21, 2013, the Texas Legislature passed H.B. 788 which is intended to streamline GHG permitting in Texas by directing the Texas Commission on Environmental Quality ("TCEQ") to promulgate rules to be approved by the EPA that would replace EPA permitting of GHGs in Texas with TCEQ permitting. The bill was signed by the Governor on June 14, 2013 and is effective. TCEQ proposed regulations to implement H.B. 788 on October 23, 2013, a public hearing on these proposed regulations was held on December 5, 2013, and comments on the proposal were due on December 9, 2013. Depending on how and when TCEQ finalizes its proposed regulations implementing H.B. 788, TCEQ could impose additional requirements on our operations that could increase our operating costs.

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, treat or process 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 CFTC and the SEC and other regulatory authorities to promulgate certain rules and regulations, including rules and regulations relating to the regulation of certain swaps entities, the clearing of certain swaps through central counterparties, the execution of certain swaps on designated contract markets or swap execution facilities, and the reporting and recordkeeping of swaps. While certain regulations have been promulgated and are already in effect, the rulemaking and implementation process is still ongoing, and we cannot yet predict the ultimate effect of the rules and regulations on our business.

The CFTC has previously established position limits on certain core futures and equivalent swaps contracts in the major energy, including natural gas, and other markets, with exceptions for certain bona fide hedging transactions. The CFTC's original position limits rules were vacated by a federal district court on September 28, 2012. On November 5, 2013, the CFTC proposed a new rulemaking on position limits and aggregation; however, it is uncertain at this time whether, when, and to what extent the CFTC's position limits rules will become final and effective.

In December 2012, the CFTC published final rules regarding mandatory clearing of certain classes of interest rate swaps and certain classes of index credit default swaps and setting compliance dates of March 11, 2013, June 10, 2013, and, for commercial end users of swaps, September 9, 2013. At this time, the CFTC has not proposed any rules designating other classes of swaps, including physical commodity swaps, for mandatory clearing. Although we may qualify for the end-user exception from the mandatory clearing and trade execution requirements for our swaps entered into to hedge commercial risks, mandatory clearing and trade execution requirements applicable to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. In addition, for uncleared swaps, the CFTC or federal banking regulatory authorities may require our counterparties to require that we enter into credit support documentation and/or post margin as collateral; however, the proposed margin rules are not yet final and therefore the application of those rules to us is uncertain at this time.

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.

Terrorist attacks and threats, escalation of military activity in response to these attacks or acts of war could have a material adverse effect on our business, financial condition or results of operations.

Terrorist attacks and threats, escalation of military activity or acts of war may have significant effects on general economic conditions, fluctuations in consumer confidence and spending and market liquidity, each of which could materially and adversely affect our business. Future terrorist attacks, rumors or threats of war, actual conflicts involving the United States or its allies, or military or trade disruptions may significantly affect our operations and those of our customers. Strategic targets, such as energy-related assets, may be at greater risk of future attacks than other targets in the United States. Disruption or significant increases in energy prices could result in government-imposed price controls. It is possible that any of these occurrences, or a combination of them, could have a material adverse effect on our business, financial condition and results of operations.

Our operations depend on the use of information technology ("IT") systems that could be the target of a cyber-attack.

Our operations depend on the use of sophisticated IT systems. Our IT systems and networks, as well as those of our customers, vendors and counterparties, may become the target of cyber-attacks or information security breaches, which in turn could result in the unauthorized release and misuse of confidential or proprietary information as well as disrupt our operations or damage our facilities or those of third parties, which could have a material adverse effect on our revenues and increase our operating and capital costs, which could reduce the amount of cash otherwise available for distribution. We may be required to incur additional costs to modify or enhance our systems or in order to try to prevent or remediate any such attacks.

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 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 management is required to assess our internal control over financial reporting pursuant to Section 404 of the Sarbanes-Oxley Act of 2002, our independent registered public accounting firm will not be required to formally attest to the effectiveness of our internal control over financial reporting until 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, through its ownership of SMP Holdings, indirectly 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. Our general partner and its affiliates, including Summit Investments and SMP Holdings, have conflicts of interest with us and they may favor their own interests to the detriment of us and our unitholders.

SMP Holdings, which is owned and controlled by 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, SMP Holdings. Conflicts of interest will arise between SMP Holdings, Summit Investments, and 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 SMP Holdings and 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 SMP Holdings or 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. SMP Holdings or Summit Investments may choose to shift the focus of their investment and growth to areas not served by our assets.
- SMP Holdings and Summit Investments are not limited in their 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 SMP Holdings and Summit Investments and their 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.
- 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 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. In January 2014, Summit Investments acquired an interest in two entities (collectively, “Ohio Gathering”), that own, operate and are developing significant midstream infrastructure in southeastern Ohio consisting of a liquids-rich natural gas gathering system, a dry natural gas gathering system and a condensate transportation, storage and stabilization facility in the core of the Utica Shale.

While Summit Investments has indicated that it intends to offer us the opportunity to acquire its interests in Ohio Gathering, 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.

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 14,388,469 publicly traded common units at December 31, 2013. In addition, SMP Holdings, which controls our general partner, owned 14,691,397 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:

- 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 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, 2013, SMP Holdings, which owns and controls our general partner, owned 14,691,397 common units and 24,409,850 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 SMP Holdings and 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.

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, holders of our common units 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, in its capacity as sole member of SMP Holdings. 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 $66\frac{2}{3}$% of all outstanding limited partner units voting together as a single class is required to remove our general partner. As of December 31, 2013, SMP Holdings, which controls our general partner, owned 14,691,397 common units out of 29,079,866 outstanding common units and all of our 24,409,850 subordinated 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 SMP Holdings 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 SMP Holdings or Summit Investments selling or contributing additional midstream assets to us, as SMP Holdings and 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.

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.

SMP Holdings 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, 2013, SMP Holdings held an aggregate of 14,691,397 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 SMP Holdings 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, 2013, SMP Holdings owned 14,691,397 common units and 24,409,850 subordinated units. At the end of the subordination period, assuming no acquisitions, dispositions, retirement or additional issuance of common units (other than upon the conversion of the subordinated units), SMP Holdings will own 39,101,247 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.

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 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.

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.

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 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 the positions we take and such positions may not ultimately be sustained. 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 a unitholder sells its common units, a gain or loss will be recognized for federal income tax purposes equal to the difference between the amount realized and the unitholder's tax basis in those common units. Because distributions in excess of a unitholder's allocable share of its net taxable income decrease its tax basis in its common units, the amount, if any, of such prior excess distributions with respect to the common units the it sells will, in effect, become taxable income to the unitholder if it sells such common units at a price greater than the its tax basis in those common units, even if the price it receives is less than its original cost. Furthermore, a substantial portion of the amount realized on any sale of a unitholder's 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 a unitholder sells its common units, it 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. 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 our unitholders. It also could affect the timing of these tax benefits or the amount of gain from our unitholders' sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to our unitholders' 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 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, our unitholders 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 currently conduct business in West Virginia, North Dakota, Texas and Colorado. Some of these states currently impose 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 2. Properties.

We currently have four natural gas gathering systems which provide our gathering, treating and processing services. They are (i) the Mountaineer Midstream system located in Doddridge and Harrison counties, West Virginia, (ii) the Bison Midstream system located in Mountrail and Burke counties, North Dakota, (iii) the DFW Midstream system located primarily in Tarrant County, Texas and (iv) the Grand River system located primarily in Garfield, Mesa and Rio Blanco counties, Colorado and Uintah and Grand counties, Utah. 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 valid title to these lands. The remainder of the land on which our major facilities are located are held by us pursuant to long-term leases or 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 valid 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 corporate offices in Houston, Texas, Denver, Colorado and Atlanta, Georgia.

Item 6. Selected Financial Data.

The selected consolidated financial data presented as of December 31, 2013, 2012, 2011, 2010 and 2009 and for the years ended December 31, 2013, 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.

These financial statements reflect the results of operations of (i) Bison Midstream since February 16, 2013, (ii) Mountaineer Midstream since June 22, 2013, and (iii) Red Rock Gathering since October 23, 2012. SMLP recognized its acquisitions of Bison Midstream (the "Bison Drop Down") and Red Rock Gathering (the "Red Rock Drop Down") at Summit Investments' historical cost because the acquisitions were executed by entities under common control. The excess of Summit Investments' net investment in Bison Midstream over the purchase price paid by SMLP was recognized as an addition to partners' capital. The excess of the purchase price paid by SMLP over Summit Investments' net investment in Red Rock Gathering was recognized as a reduction to partners' capital. Due to the common control aspect, the Bison Drop Down and the Red Rock Drop Down were accounted for by the Partnership on an “as if pooled” basis for the periods during which common control existed.

SMLP completed its IPO on October 3, 2012. For the year ended December 31, 2012, these financial statements include the Predecessor's results of operations through the date of SMLP's 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.

The selected consolidated 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 Corp. 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 Corp. 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 Corp. 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 and other data as of the date indicated.

	December 31, 2013	December 31, 2012	December 31, 2011	December 31, 2010	December 31, 2009
	(In thousands, except per-unit amounts)				
Balance sheet data:					
Total assets	$ 1,883,739	$ 1,280,939	$ 1,030,264	$ 340,095	$ 215,982
Total long-term debt	586,000	199,230	349,893	—	—
Partners' capital	1,201,737	1,030,248	n/a	n/a	n/a
Membership interests	n/a	n/a	640,818	307,370	185,066
Other data:					
Market price per common unit	$ 36.65	$ 19.83	n/a	n/a	n/a

n/a - Not applicable

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
	2013	2012	2011	2010		
	(In thousands, except per-unit amounts)					
Statement of operations data:						
Total revenues	$ 292,920	$ 174,423	$ 103,552	$ 31,676	$ 1,733	$ 1,910
Total costs and expenses	219,606	117,987	61,864	23,412	8,350	2,492
Interest expense	19,173	7,340	1,029	—	—	247
Affiliated interest expense	—	5,426	2,025	—	—	—
Net income (loss)	53,304	42,997	37,951	8,172	(6,606)	(837)
Earnings per limited partner unit:						
Common unit – basic	$ 0.86	$ 0.35	n/a	n/a	n/a	n/a
Common unit – diluted	$ 0.86	$ 0.35	n/a	n/a	n/a	n/a
Subordinated unit – basic and diluted	$ 0.79	$ 0.35	n/a	n/a	n/a	n/a
Other financial data:						
EBITDA	$ 144,195	$ 93,302	$ 53,363	$ 12,353	$ (6,293)	$ 300
Adjusted EBITDA	164,839	105,946	56,803	12,353	(6,293)	300
Capital expenditures	109,376	77,296	78,248	153,719	19,519	40,777
Acquisition capital expenditures (1)	458,914	—	589,462	—	44,896	—
Distributable cash flow	128,141	90,947	50,980	11,726	(6,275)	300
Distributions declared per unit (2)	1.795	0.410	n/a	n/a	n/a	n/a

n/a - Not applicable
(1) Reflects cash paid and value of units issued, if any, to fund the acquisitions of the Bison Midstream and Mountaineer Midstream systems in 2013, Red Rock Gathering, LLC ("Red Rock") in 2012, the Grand River system in 2011 and the DFW Midstream system in 2009.
(2) For 2013, represents the distributions declared in April 2013 for the first quarter of 2013, July 2013 for the second quarter of 2013, October 2013 for the third quarter of 2013 and January 2014 for the fourth quarter of 2013. For 2012, represents the

distribution declared in January 2013 for the fourth quarter of 2012.

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.

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, 2013, follows.

	Quarter ended December 31, 2013	Quarter ended September 30, 2013	Quarter ended June 30, 2013	Quarter ended March 31, 2013
	(In thousands, except per-unit amounts)			
Total revenues	$ 83,455	$ 76,019	$ 71,461	$ 61,984
Net income attributable to partners	$ 16,345	$ 6,691	$ 8,068	$ 12,480
Less: net income attributable to general partner, including IDRs	490	134	161	250
Net income attributable to limited partners	$ 15,855	$ 6,557	$ 7,907	$ 12,230
Earnings per limited partner unit:				
Common unit – basic	$ 0.30	$ 0.12	$ 0.16	$ 0.25
Common unit – diluted	$ 0.29	$ 0.12	$ 0.16	$ 0.25
Subordinated unit – basic and diluted	$ 0.30	$ 0.12	$ 0.16	$ 0.25

	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	$ 57,558	$ 40,975	$ 40,107	$ 35,783
Net income attributable to partners and 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 limited partner unit:				
Common unit – basic	$ 0.35			
Common unit – diluted	$ 0.35			
Subordinated unit – basic and diluted	$ 0.35			

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

This MD&A is intended to inform the reader about matters affecting the financial condition and results of operations of SMLP and its subsidiaries. As a result, the following discussion should be read in conjunction with the audited consolidated financial statements and notes thereto included in this report. 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 Forward-Looking Statements included in our Current Report on Form 8-K as filed with the SEC on July 3, 2014. Actual results may differ materially from those contained in any forward-looking statements.

Overview

We are a growth-oriented limited partnership focused on developing, 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 gather, treat and process natural gas from both dry gas and liquids-rich regions. 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, or NGLs, in addition to methane. We currently operate natural gas gathering systems in four unconventional resource basins: (i) the Appalachian Basin, which includes the Marcellus Shale formation in northern West Virginia; (ii) the Williston Basin, which includes the Bakken and Three Forks shale formations in northwestern North Dakota; (iii) the Fort Worth Basin, which includes the Barnett Shale formation in north-central Texas; and (iv) the Piceance Basin, which includes the Mesaverde formation and the Mancos and Niobrara shale formations in western Colorado and eastern Utah. We believe that our gathering systems are well positioned to capture additional volumes from increased producer activity in these regions in the future.

Our results are driven primarily by the volumes of natural gas that we gather, treat and process across our systems. We contract with producers to gather natural gas from pad sites and central receipt points connected to our systems, which we then compress, dehydrate, treat and/or process for delivery to downstream pipelines for ultimate delivery to third-party processing plants and/or end users.

We generate the majority of our revenue from the natural gas gathering, treating and processing services that we provide to our natural gas producer customers under long-term, primarily fee-based natural gas gathering and processing agreements. Under these agreements, we are paid a fixed fee based on the volume and thermal content of the natural gas we gather, treat and process. These agreements enhance the stability of our cash flows by providing 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 earn revenue from our marketing of natural gas and natural gas liquids and from the sale of physical natural gas purchased from our customers under percent-of-proceeds and keep-whole arrangements, which can expose us to commodity price risk. We sell condensate retained from our gathering services at Grand River Gathering.

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, treat and process. If our customers delay drilling or temporarily shut-in production, our minimum volume commitments assure us that we will receive a certain amount of revenue from our customers.

Most of our gas gathering and processing agreements are underpinned by areas of mutual interest and MVCs. Our areas of mutual interest cover over 1.4 million acres in the aggregate, have original terms up to 25 years, and provide that any natural gas producing wells drilled by our customers within the areas of mutual interest will be shipped and/or processed on our gathering systems. The MVCs, which totaled 4.2 Tcf at December 31, 2013 and average approximately 1,230 MMcf/d through 2018, are designed to ensure that we will generate a certain amount of revenue from each customer over the life of the respective gas gathering and/or processing 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 from two to 13 years and, as of December 31, 2013, had a weighted-average remaining life of 10.3 years, assuming minimum throughput volumes for the remainder of the term.

For additional information on our gathering systems, see the "Business" section included in this Annual Report and "Results of Operations—Combined Overview" below.

Trends and Outlook

Our business has been, and we expect our future business to continue to be, affected by the following key trends:

- Natural gas supply and demand dynamics;
- Growth in production from U.S. shale plays;
- Interest rate environment; and
- Rising operating costs and inflation.

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 and crude oil 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 seen an increase with NYMEX natural gas futures price at $4.23 per MMBtu as of December 31, 2013 compared with $3.35 per MMBtu as of December 31, 2012. These marks compare with a high of $13.58 per MMBtu in July 2008. The increase in natural gas prices from 2012 to 2013 was primarily attributable to an unseasonably cold winter in 2013, which resulted in higher than normal residential consumption of natural gas. As a result, the amount of natural gas in storage in the continental United States decreased to approximately 3.0 Tcf as of December 27, 2013 from approximately 3.5 Tcf as of December 28, 2012, compared with a ten-year historical December average of 3.3 Tcf.

Current natural gas prices continue to be lower than historical prices due in part to increased production, especially from unconventional sources, such as natural gas shale plays 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 19.2% to 65.7 Bcf/d in 2012 from from 55.1 Bcf/d in 2008. Over the same time period, natural gas consumption increased only 9.7% to 69.8 Bcf/d. In response to lower natural gas prices, the number of natural gas drilling rigs has declined from approximately 1,347 as of December 26, 2008 to approximately 374 as of December 27, 2013, according to Baker Hughes, as a number of producers have reallocated capital from natural gas exploration and production activities to higher yielding crude oil 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, coal-fired power plants generated 37% of the electricity in the United States in 2012, compared with 48% in 2008. In January 2013, the EIA projected total annual domestic consumption of natural gas to increase from approximately 62.7 Bcf/d in 2009 to approximately 80.7 Bcf/d in 2040. Consistent with the rise in consumption, the EIA projects that total domestic natural gas production will continue to grow through 2040 to 90.7 Bcf/d. The EIA also projects the United States to be a net exporter of liquefied natural gas, or LNG, by 2016, with U.S. exports of LNG projected to rise to 4.4 Bcf/d in 2027. 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.

In addition, in connection with the Bison Drop Down, we are now affected by crude oil supply and demand dynamics. Crude oil has been the focus of recent upstream activity in the United States and continues to play a significant role in the energy market. United States domestic crude oil production has increased by 49% from 5.0 MMBbl/d in 2008 to 7.5 MMBbl/d in 2013 according to the EIA. Over the long term, the domestic production of crude oil will continue to increase according to the EIA. The growth will continue to come from increases in shale and tight crude oil production, which will be spurred by additional technological advances and elevated oil prices. According to the EIA, about 25.3 billion barrels of tight oil will be produced in the U.S. cumulatively from 2012 through 2040 and the Bakken Shale is expected to contribute 32% of this production.

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 20.7 Tcf in 2009 to 33.2 Tcf in 2040, it expects shale gas production to grow to 16.7 Tcf in 2040, representing 50% 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 when compared to most conventional plays.

In recent years, well-capitalized producers have leased large acreage positions in the Piceance Basin and the Barnett, Bakken and Marcellus shale plays and other unconventional resource plays. To help fund their drilling program in many of these areas, 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 and the Barnett, Bakken and Marcellus shale plays 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 and production 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 have continued to experience 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 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 conduct our operations in the midstream sector with four operating segments. However, due to their similar characteristics and how we manage our business, we have aggregated these segments into a single reporting segment for disclosure purposes. 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;
- operation and maintenance expenses;
- EBITDA and adjusted EBITDA; and
- distributable cash flow.

Throughput Volume

The volume of natural gas that we gather, treat and process depends on the level of production from natural gas or crude oil wells connected to our gathering 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 crude oil and natural gas wells decline 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, treat and process natural gas that has been released from commitments with our competitors.

Operation 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 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 operation 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 natural gas to third-party pipelines. With respect to the Mountaineer Midstream, Bison Midstream and Grand River systems, 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 unit-based compensation, adjustments related to MVC shortfall payments and loss on asset sales, less gain on asset sales. We define distributable cash flow as adjusted EBITDA plus cash interest income, less cash paid for interest expense and income taxes, senior notes interest expense 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, the impact of unit-based compensation or the timing of gain or loss on asset sales.

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 historical results of operations may not be comparable to its future 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 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;
- Our historical results of operations may not be comparable to our future results of operations due in part to:

  (i) Our June 2013 acquisitions. The audited consolidated financial statements reflect the results of operations of: (i) Bison Midstream since February 16, 2013 and (ii) Mountaineer Midstream since June 22, 2013. Due to the common control aspect, the Bison Drop Down was accounted for by the Partnership on an "as if pooled" basis for the periods during which common control existed. Common control began on February 16, 2013 concurrent with Summit Investments' acquisition of the assets that comprise the Bison Midstream system. For additional information, see Notes 1, 5, 6 and 13 to the audited consolidated financial statements;

  (ii) Grand River Gathering's March 2014 acquisition of Red Rock Gathering. The audited consolidated financial statements reflect the results of operations of Red Rock Gathering since October 23, 2012. Due to the common control aspect, the Red Rock Drop Down was accounted for by the Partnership on an "as if pooled" basis for the periods during which common control existed. Common control began on October 23, 2012 concurrent with Summit Investments' acquisition of Red Rock Gathering. For additional information, see Notes 1 and 13 to the audited consolidated financial statements;

  (iii) Our IPO, which was completed on October 3, 2012. Incremental public entity costs include:

    - expenses associated with annual and quarterly reporting;
    - tax return and Schedule K-1 preparation and distribution expenses;
    - Sarbanes-Oxley compliance expenses;
    - expenses associated with listing on the NYSE;
    - independent auditor fees;
    - legal fees;
    - investor relations expenses;
    - registrar and transfer agent fees;
    - director and officer liability insurance costs; and
    - director compensation.

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

  (iv) Our October 2011 acquisition of Grand River Gathering. The audited consolidated financial statements reflect the results of operations of Grand River Gathering since November 1, 2011. For additional information, see Notes 1 and 13 to the audited consolidated financial statements.

Overview of the Years Ended December 31, 2013, 2012 and 2011

Revenues. For the year ended December 31, 2013, total revenues increased $118.5 million to $292.9 million from $174.4 million largely as a result of the Red Rock Drop Down, Bison Midstream's contribution to natural gas, NGLs and condensate sales and other, Mountaineer Midstream's contribution to gathering services and other fees and an increase in revenues for the DFW Midstream system. Total revenues for the year ended December 31, 2013 included a $50.1 million contribution as a result of the Red Rock Drop Down, a $50.7 million contribution from Bison

Midstream and a $9.6 million contribution from Mountaineer Midstream.

For the year ended December 31, 2012, total revenues increased $70.9 million to $174.4 million from $103.6 million primarily as a result of the October 2011 acquisition of the Grand River system, increased throughput volumes on the DFW Midstream system due to its continued build out and the fourth quarter 2012 impact of the Red Rock Drop Down. Total revenues for the year ended December 31, 2012 included a $80.9 million contribution from Grand River Gathering (including an $8.9 million contribution from the Red Rock Drop Down), compared with a $12.8 million contribution in 2011.

Costs and Expenses. For the year ended December 31, 2013, total costs and expenses increased $101.6 million, or 86%, primarily as a result of the Red Rock Drop Down, the acquisitions of Bison Midstream and Mountaineer Midstream and an increase in expenses at DFW Midstream. Total costs and expenses for the year ended December 31, 2013 included a $40.4 million contribution as a result of the Red Rock Drop Down, a $53.5 million contribution from Bison Midstream and a $7.3 million contribution from Mountaineer Midstream.

During the year ended December 31, 2012, total costs and expenses increased $56.1 million, or 91%, largely driven by the Red Rock Drop Down and Grand River Gathering's contribution to operation and maintenance expense and depreciation and amortization expense. Total costs and expenses for the year ended December 31, 2012 included a $62.3 million contribution from Grand River (including a $7.7 million contribution from the Red Rock Drop Down), compared with a $8.7 million contribution in 2011.

Volumes. Our revenues are primarily attributable to the volume of natural gas that we gather, treat and process and the rates we charge for those services. For the year ended December 31, 2013, our aggregate throughput volumes increased to an average of 1,138 MMcf/d compared with an average of 952 MMcf/d for the year ended December 31, 2012. The 2013 increase in volume throughput largely reflects the combined effect of contributions from Bison Midstream and Mountaineer Midstream, an increase in volume throughput on the Grand River system and a temporary production curtailment by one of our largest producer customers on the DFW Midstream system during the first and second quarters of 2012.

For the year ended December 31, 2012, our combined throughput volumes increased to an average of 952 MMcf/d compared with an average of 431 MMcf/d for the year ended December 31, 2011. The 2012 increase in volume throughput largely reflects the contribution from the Grand River system and the continued development of the DFW Midstream system as well as the 2012 impact of the temporary production curtailment noted above.

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

	Year ended December 31,			Percentage Change	
	2013	2012	2011	2013 v. 2012	2012 v. 2011
		(Dollars in thousands)			
Revenues:					
Gathering services and other fees	$ 205,346	$ 154,139	$ 91,421	33%	69 %
Natural gas, NGLs and condensate sales and other	88,606	20,476	12,439	*	65 %
Amortization of favorable and unfavorable contracts (1)	(1,032)	(192)	(308)	*	*
Total revenues	292,920	174,423	103,552	68%	68 %
Costs and expenses:					
Operation and maintenance	72,465	53,882	29,855	34%	80 %
Cost of natural gas and NGLs	44,233	3,224	—	*	*
General and administrative	30,105	22,182	17,476	36%	27 %
Transaction costs	2,841	2,025	3,166	40%	(36)%
Depreciation and amortization	69,962	36,674	11,367	91%	*
Total costs and expenses	219,606	117,987	61,864	86%	91 %
Other (expense) income	(108)	9	12	*	(25)%
Interest expense	(19,173)	(7,340)	(1,029)	*	*
Affiliated interest expense	—	(5,426)	(2,025)	*	*
Income before income taxes	54,033	43,679	38,646	24%	13 %
Income tax expense	(729)	(682)	(695)	7%	(2)%
Net income	$ 53,304	$ 42,997	$ 37,951	24%	13 %
Other Financial Data:					
EBITDA (2)	$ 144,195	$ 93,302	$ 53,363	55%	75 %
Adjusted EBITDA (2)	164,839	105,946	56,803	56%	87 %
Capital expenditures (3)	109,376	77,296	78,248	42%	(1)%
Acquisition capital expenditures (4)	458,914	—	589,462	*	*
Distributable cash flow (2)(3)	128,141	90,947	50,980	41%	78 %
Operating Data:					
Miles of pipeline (end of period)	2,283	1,874	372	22%	*
Aggregate average throughput (MMcf/d)	1,138	952	431	20%	121 %

* Not considered meaningful

(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) Includes transaction costs. These unusual and non-recurring expenses are settled in cash. 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.

(3) 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. For the year ended December 31, 2012, distributable cash flow includes an estimate for the portion of total capital expenditures that were maintenance capital expenditures for nine months ended September 30, 2012. For the year ended December 31, 2011, distributable cash flow includes an estimate for the portion of total capital expenditures that were maintenance capital expenditures.

(4) Reflects cash paid and value of units issued, if any, to fund the acquisitions of the Bison Midstream and Mountaineer Midstream systems in 2013 and the Grand River system in 2011.

System Overview. Operating data by system as of or for the year ended December 31 follows.

	Mountaineer Midstream (1)	Bison Midstream (1)	DFW Midstream			Grand River		
	2013	2013	2013	2012	2011	2013	2012	2011
Miles of pipeline (end of year)	41	343	119	110	104	1,780	1,764	268
Aggregate average annual throughput (MMcf/d)	87 (2)	14 (3)	391	354	333	646	598 (4)	98 (5)
Average fee per Mcf	n/a	$ 3.86	$ 0.59	$ 0.58	$ 0.59	$ 0.40	$ 0.31	$ 0.31
Total Remaining MVC Commitment (Bcf)	n/a	29	263	372	488	2,374	2,597	2,144
Average daily MVCs through 2018 (MMcf/d) (end of year)	n/a	14	141	163	175	713	696	502
Weighted-average remaining contract life (end of year) (6)	n/a	6.5	6.2	7.2	8.2	11.2	12.0	13.6

(1) Gathering system was not an asset of SMLP during 2012 and 2011.
(2) For the year ended December 31, 2013. For the period of SMLP's ownership in 2013, average throughput was 164 MMcf/d.
(3) For the year ended December 31, 2013. For the period of SMLP's ownership in 2013, average throughput was 16 MMcf/d.
(4) For the year ended December 31, 2012. For the period of SMLP's ownership of Red Rock Gathering in 2012, average throughput was 715 MMcf/d.
(5) For the year ended December 31, 2011. For the period of SMLP's ownership of Grand River Gathering in 2011, average throughput was 586 MMcf/d.
n/a - Contract terms excluded for confidentiality purposes.
(6) Weighted average based on total remaining MVC (total remaining MVCs multiplied by average rate).

<u>Mountaineer Midstream.</u> For the year ended December 31, 2013, volume throughput for the Mountaineer Midstream system, which was acquired in late June 2013, was impacted by temporary processing capacity curtailments resulting from a line break on one of MarkWest’s NGL pipelines which forced the Mountaineer Midstream system to curtail its natural gas deliveries to MarkWest's Sherwood Processing Complex beginning in August 2013. The affected NGL pipeline was returned to service mid-October 2013 and returned to pre-curtailment levels by November 2013. Despite the curtailment, Mountaineer Midstream experienced sequential quarterly volume throughput increases from Antero, its sole customer, consistent with Antero’s development activities upstream of Mountaineer Midstream’s gathering infrastructure and in line with MarkWest’s processing capacity expansions at its Sherwood Processing Complex.

<u>Bison Midstream.</u> Bison Midstream system volume throughput during the year ended December 31, 2013, was impacted by temporary operational interruptions across the system due to water hydrate issues during the third and fourth quarters of 2013. These operational issues were resolved during the first quarter of 2014. Volume throughput in 2013 was also impacted by temporary interruptions, which occurred throughout the second, third and fourth quarters of 2013 as we continued to install new compression assets designed to increase the system's throughput capacity. Lower volume throughput at Bison Midstream was partially offset by a new natural gas purchase agreement with Aux Sable Midstream, LLC which became effective in August 2013 and provides for long-term access to natural gas processing capacity and improved processing economics for Bison Midstream and its customers.

<u>DFW Midstream.</u> The increase in DFW Midstream system volume throughput during the year ended December 31, 2013 was primarily due to the prior-year impact of a temporary production curtailment by one of our largest producer customers in the first and second quarters of 2012. Volume throughput for the DFW Midstream system in 2013 was also impacted by multiple customers temporarily shutting-in several large pad sites during the third and fourth quarters to drill and/or complete new wells. While this activity is beneficial over the long term, it can create

volume and cash flow volatility. Volume throughput in 2013 also reflects higher volumes in the first quarter of 2013, which benefited from the January 2013 commissioning of a compressor which increased system throughput capacity from 410 MMcf/d to 450 MMcf/d.

During the year ended December 31, 2012, volume throughput on the DFW Midstream system increased largely as a result of the system's continued build-out and an increase in well connections, partially offset by the impact of the production curtailment noted above.

Grand River. Grand River system volume throughput increased during the year ended December 31, 2013 largely as a result of the Red Rock Drop Down, partially offset by lower drilling activity and the natural decline of previously drilled Mancos/Niobrara wells in the Orchard Field. For the year ended December 31, 2012, excluding the fourth quarter 2012 contribution from the Red Rock Drop Down, volume throughput declined relative to our period of ownership in 2011 primarily due to lower drilling activity and the natural decline of previously drilled wells mentioned above. Certain of our gas gathering agreements for the Grand River system include MVCs that, in the aggregate, increase over the near term. The majority of the volume declines came from producers that are subject to MVCs. As a result, the lower volume throughput from these producers in 2013 primarily translated into larger MVC shortfall payments.

Gathering services and other fees. Gathering services and other fees increased during the year ended December 31, 2013, largely as a result of the Red Rock Drop Down and our acquisitions of the Bison Midstream and Mountaineer Midstream systems and throughput volumes on the DFW Midstream system. Gathering services and other fees in 2013 included a $12.6 million contribution from the Bison Midstream system and a $9.6 million contribution from the Mountaineer Midstream system. The aggregate average throughput rate for the year ended December 31, 2013 was approximately $0.50 per Mcf, compared with approximately $0.41 per Mcf for the year ended December 31, 2012. The year-over-year increase was largely driven by the proportionate contribution of throughput volumes from our DFW Midstream and Bison Midstream systems, which have higher average gathering fees per Mcf. Additionally, the year-over-year increase in aggregate average throughput rate benefited from gas gathering agreement provisions which increased the average gas gathering fee per Mcf on our Grand River system beginning in January 2013. These contractual provisions helped offset the financial impact of the volume declines on the Grand River system. The impact of higher average gathering rates for the DFW Midstream system and the Bison Midstream system and the MVC contractual provisions for the Grand River system was partially offset by the lower average gathering fee per Mcf received on the Mountaineer Midstream system. For the year ended December 31, 2013, gathering services and other fees included a $30.8 million contribution as a result of the Red Rock Drop Down, compared with a $4.8 million contribution in 2012.

Gathering services and other fees increased during the year ended December 31, 2012, largely due to the contribution from the Grand River system, including the fourth quarter 2012 impact of the Red Rock Drop Down. 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 $67.9 million in 2012 (including the $4.8 million contribution as a result of the Red Rock Drop Down), compared with $11.0 million in 2011.

Natural gas, NGLs and condensate sales and other. The increase in natural gas, NGLs and condensate sales and other for the year ended December 31, 2013, was primarily a result of the Red Rock Drop Down and the contribution from the Bison Midstream system, higher throughput volumes and the associated retainage on our DFW Midstream system, and an increase in the prices we were able to obtain for natural gas sales. Bison Midstream accounted for $38.2 million of the total increase in natural gas, NGLs and condensate sales and other for the year ended December 31, 2013. For the year ended December 31, 2013, natural gas, NGLs and condensate sales and other included a $19.3 million contribution as a result of the Red Rock Drop Down, compared with a $4.2 million contribution in 2012.

Natural gas and condensate sales increased during the year ended December 31, 2012, primarily reflecting the contribution of the Grand River system, including the fourth quarter 2012 impact of the Red Rock Drop Down. Revenue associated with condensate sales for the Grand River system was approximately $7.7 million in 2012 (including the $4.2 million contribution as a result of the Red Rock Drop Down), compared with $0.6 million in 2011.

Operation and Maintenance Expense. Operation and maintenance expense increased during the year ended December 31, 2013, largely as a result of the Red Rock Drop Down and expenses associated with the Bison Midstream and Mountaineer Midstream systems, a $6.8 million increase in field employee costs, primarily for the Grand River system as a result of the Red Rock Drop Down, a $4.3 million increase in power-related costs primarily for the DFW Midstream system, a $2.9 million increase in property tax expense largely due to the Red Rock Drop Down, and a $1.6 million increase in carbon dioxide expenses primarily for the DFW Midstream system. The increase in operation and maintenance expense was partially offset by a $2.8 million decline in compressor lease and contract maintenance expenses primarily as a result of our purchase of previously leased compression assets in the first quarter of 2013. For the year ended December 31, 2013, operation and maintenance expense was $4.2 million for the Bison Midstream system and $2.4 million for the Mountaineer Midstream system. Operation and maintenance expense also included a $12.5 million contribution as a result of the Red Rock Drop Down in 2013, compared with a $2.2 million contribution in 2012.

During the year ended December 31, 2012, operation and maintenance expense increased largely as a result of Grand River system expenses incurred in 2012, including the fourth quarter 2012 impact of the Red Rock Drop Down, partially offset by a decline in expenses for the DFW Midstream system. The decrease in operation 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. Operation and maintenance expense for the Grand River system was $28.7 million for the year ended December 31, 2012 (including the $2.2 million contribution as a result of the Red Rock Drop Down), compared with $3.9 million for the year ended December 31, 2011.

Cost of Natural Gas and NGLs. Cost of natural gas and NGLs represents the expenses associated with the percent-of-proceeds arrangements under which the Grand River and Bison Midstream systems sell natural gas purchased from our customers. For the year ended December 31, 2013, cost of natural gas and NGLs included a $13.2 million contribution as a result of the Red Rock Drop Down, compared with a $3.2 million contribution in 2012.

General and Administrative Expense. General and administrative expense increased during the year ended December 31, 2013, largely as a result of an increase in salaries, benefits and incentive compensation primarily due to the Red Rock Drop Down, increased head count and an increase in professional services expense. The Bison Midstream system accounted for $2.2 million and the Mountaineer Midstream system accounted for $0.8 million of general and administrative expense for the year ended December 31, 2013. For the year ended December 31, 2013, general and administrative expense included a $5.5 million contribution as a result of the Red Rock Drop Down, compared with a $0.8 million contribution in 2012.

During the year ended December 31, 2012, general and administrative expense increased largely as a result of an increase of expenses due to the acquisition of the Grand River system in October 2011, including the fourth quarter 2012 impact of the Red Rock Drop Down. 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 from 2011 which included the initial recognition of expense associated with awards granted in 2010 and 2009 as well as an award modification in 2011 to remove a rate of return payout hurdle which also increased non-cash unit-based compensation expense.

Transaction Costs. Transaction costs were $2.8 million for the year ended December 31, 2013, of which $2.0 million related to the acquisition of the Mountaineer Midstream system and $0.8 million related to the acquisition of the Bison Midstream system. Transaction costs of $2.0 million in 2012 largely reflect costs associated with Summit Investments' acquisition of the Red Rock Gathering in October 2012. For the year ended December 31, 2011, transaction costs of $3.2 million were primarily related to the acquisition of the Grand River system.

Depreciation and Amortization Expense. Depreciation and amortization expense increased during the year ended December 31, 2013 largely due to the Red Rock Drop Down and recognizing depreciation and amortization from the Bison Midstream and Mountaineer Midstream systems. An increase in contract amortization for the Grand River system and assets placed into service in connection with the development of the DFW Midstream and Grand River systems also contributed to the increase. The Bison Midstream system accounted for $16.1 million of depreciation and amortization expense for the year ended December 31, 2013. The Mountaineer Midstream system also contributed $4.0 million to the increase in depreciation and amortization expense for the year ended December 31, 2013. Depreciation and amortization expense also included a $9.1 million contribution as a result of the Red Rock Drop Down in 2013, compared with a $1.4 million contribution in 2012.

During the year ended December 31, 2012, depreciation and amortization expense increased largely due to the acquisition of the Grand River system in October 2011, including the fourth quarter 2012 impact of the Red Rock Drop Down 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 $24.5 million in 2012 (including the $1.4 million contribution as a result of the Red Rock Drop Down), compared with $3.2 million in 2011.

Interest Expense and Affiliated Interest Expense. The increase in interest expense during the year ended December 31, 2013, primarily reflects our issuance of $300.0 million of 7.50% senior notes in June 2013. Additionally, higher balances on our revolving credit facility beginning in May 2012 as well as an increase in commitment fees as a result of the May 2012 amendment and restatement of the revolving credit facility, which increased our borrowing capacity by $265.0 million and the June 2013 amendment and restatement, which increased our borrowing capacity by $50.0 million also contributed to the increase in interest expense.

The increase in interest expense during the year ended December 31, 2012, was primarily a result of the higher 2012 balances on the revolving credit facility that we obtained in May 2011. Affiliated interest expense for the year ended December 31, 2012 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 repaid in July 2012.

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 provided by 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.

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,		
	2013	2012	2011
	(In thousands)		
Reconciliation of Net Income to EBITDA, Adjusted EBITDA and Distributable Cash Flow:			
Net income (1)	$ 53,304	$ 42,997	$ 37,951
Add:			
Interest expense	19,173	12,766	3,054
Income tax expense	729	682	695
Depreciation and amortization expense	69,962	36,674	11,367
Amortization of favorable and unfavorable contracts	1,032	192	308
Less:			
Interest income	5	9	12
EBITDA (1)	$ 144,195	$ 93,302	$ 53,363
Add:			
Unit-based compensation	3,506	1,876	3,440
Adjustments related to MVC shortfall payments (2)	17,025	10,768	—
Loss on asset sales	113	—	—
Adjusted EBITDA (1)	$ 164,839	$ 105,946	$ 56,803
Add:			
Interest income	5	9	12
Less:			
Cash interest paid	9,016	8,283	2,463
Senior notes interest expense (3)	12,125	—	—
Cash taxes paid	660	650	223
Maintenance capital expenditures (4)	14,902	6,075	3,149
Distributable cash flow	$ 128,141	$ 90,947	$ 50,980

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(1) Includes transaction costs. These unusual and non-recurring expenses are 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) Senior notes interest expense represents interest expense recognized and accrued during the period. Interest of 7.50% on the $300.0 million senior notes is paid in cash semi-annually in arrears on January 1 and July 1 until maturity in July 2021.

(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. For the years ended December 31, 2012 and 2011, the calculation of distributable cash flow and adjusted distributable cash flow includes an estimate for the portion of total capital expenditures that were maintenance capital expenditures.

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

	Year ended December 31,		
	2013	2012	2011
	(In thousands)		
Reconciliation of Net Cash Provided by Operating Activities to EBITDA, Adjusted EBITDA and Distributable Cash Flow:			
Net cash provided by operating activities (1)	$ 140,689	$ 89,392	$ 39,942
Add:			
Interest expense (2)	16,927	5,882	469
Income tax expense	729	682	695
Changes in operating assets and liabilities	(10,526)	(769)	15,709
Less:			
Unit-based compensation	3,506	1,876	3,440
Interest income	5	9	12
Loss on asset sales	113	—	—
EBITDA (1)	$ 144,195	$ 93,302	$ 53,363
Add:			
Unit-based compensation	3,506	1,876	3,440
Adjustments related to MVC shortfall payments (3)	17,025	10,768	—
Loss on asset sales	113	—	—
Adjusted EBITDA (1)	$ 164,839	$ 105,946	$ 56,803
Add:			
Interest income	5	9	12
Less:			
Cash interest paid	9,016	8,283	2,463
Senior notes interest expense (4)	12,125	—	—
Cash taxes paid	660	650	223
Maintenance capital expenditures (5)	14,902	6,075	3,149
Distributable cash flow	$ 128,141	$ 90,947	$ 50,980

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(1) Includes transaction costs. These unusual and non-recurring expenses are settled in cash. For additional information, see "Results of Operations" above.

(2) 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 pay-in-kind interest on the promissory notes payable to our Sponsors. For the year ended December 31, 2013, interest expense excluded $2.2 million of amortization of deferred loan costs. For the year ended December 31, 2012, interest expense excluded $1.5 million of amortization of deferred loan costs and $5.4 million of pay-in-kind interest. For the year ended December 31, 2011, interest expense excluded $0.6 million of amortization of deferred loan costs and $2.0 million of pay-in-kind interest.

(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) Senior notes interest expense represents interest expense recognized and accrued during the period. Interest of 7.50% on the $300.0 million senior notes is paid in cash semi-annually in arrears on January 1 and July 1 until maturity in July 2021.

(5) 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. For the years ended December 31, 2012 and 2011, the calculation of distributable cash flow and adjusted distributable cash flow includes an estimate for the portion of total capital expenditures that were maintenance capital expenditures.

Liquidity and Capital Resources

In October 2012, we completed an IPO of our common units. In June 2013, we completed an offering of senior notes and issued common limited partner units and general partner interests in connection with the Bison Drop Down and the Mountaineer Acquisition.

In October 2013, SMLP filed a shelf registration statement on Form S-3 with the SEC to register up to $1.2 billion of equity and debt securities in primary offerings as well as all of the 14,691,397 common units held by SMP Holdings in accordance with our obligations under a registration rights agreement that was executed in connection with our IPO.

In November 2013, we closed on an amendment and restatement of the revolving credit facility which: (i) increased our borrowing capacity to $700.0 million, (ii) extended the maturity to November 2018, (iii) included a $200.0 million accordion feature, (iv) reduced the leverage-based pricing grid by 0.75% to a new range of 1.75% to 2.75% for LIBOR borrrowings, (v) changed the commitment fee to a leverage-based range of 0.30% to 0.50%, and (vi) added Finance Corp. as a subsidiary guarantor.

In January 2014, we filed a registration statement on Form S-4 with the SEC to offer to exchange all of the unregistered senior notes and guarantees for registered senior notes and guarantees with substantially identical terms. On March 7, 2014, the SEC declared our registration statement effective and we began the notice process to properly effect the exchange. The period during which exchanges can occur will end on April 7, 2014.

In future periods, 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.

For additional information, see Notes 1, 5 and 6 to the audited consolidated financial statements.

Long-Term Debt

Revolving Credit Facility. We have a $700.0 million senior secured revolving credit facility. The revolving credit facility is secured by the membership interests of Summit Holdings and those of its subsidiaries. Substantially all of Summit Holdings' and its subsidiaries' assets are pledged as collateral under the revolving credit facility. The facility, and Summit Holdings' obligations, are guaranteed by SMLP and each of its subsidiaries. At our option, borrowings under the revolving credit facility bear interest at a variable rate per annum equal to either (i) the London InterBank Offered Rate plus the applicable margins ranging from 1.75% to 2.75% or (ii) a base rate plus the applicable margins ranging from 0.75% to 1.75%. As of December 31, 2013, the outstanding balance of the revolving credit facility was $286.0 million and the unused portion totaled $414.0 million.

As of December 31, 2013, we were in compliance with the covenants in the revolving credit facility. There were no defaults or events of default during the year ended December 31, 2013. See Notes 1, 5, 6 and 13 to the audited consolidated financial statements for additional information.

Senior Notes. In June 2013, Summit Holdings and its 100% owned finance subsidiary, Finance Corp. (together with Summit Holdings, the "Co-Issuers"), issued $300.0 million of 7.50% senior unsecured notes maturing July 1, 2021 (the "senior notes"). The senior notes were sold within the United States only to qualified institutional buyers in reliance on Rule 144A under the Securities Act, and outside the United States only to non-U.S. persons in reliance on Regulation S under the Securities Act.

The senior notes are senior, unsecured obligations, rank equally in right of payment with all of our existing and future senior obligations and are effectively subordinated in right of payment to all of our secured indebtedness, to the extent of the collateral securing such indebtedness. SMLP and all of its subsidiaries other than the Co-Issuers (the "Guarantors") have fully and unconditionally and jointly and severally guaranteed the senior notes. SMLP has no independent assets or operations. Summit Holdings has no assets or operations other than its ownership of its wholly owned subsidiaries and activities associated with its borrowings under the revolving credit facility and the senior notes. Finance Corp. has no independent assets or operations and was formed for the sole purpose of being a co-issuer of certain of Summit Holdings' indebtedness, including the senior notes. There are no significant restrictions on the ability of SMLP or Summit Holdings to obtain funds from its subsidiaries by dividend or loan.

Under a registration rights agreement, the Co-Issuers and the Guarantors agreed to file a registration statement with the SEC pursuant to which the Co-Issuers will either offer to exchange the senior notes and the guarantees for registered notes and guarantees with substantially identical terms or, in certain circumstances, register the resale of the senior notes and their guarantees. Our registration statement for the exchange offer was declared effective by the SEC on March 7, 2014.

There were no defaults or events of default during the period from issuance through December 31, 2013. For additional information, see Note 5 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 10 to the audited consolidated financial statements.

Cash Flows

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

	Year ended December 31,		
	2013	2012	2011
	(In thousands)		
Net cash provided by operating activities	$ 140,689	$ 89,392	$ 39,942
Net cash used in investing activities	(518,791)	(77,296)	(667,710)
Net cash provided by (used in) financing activities	387,125	(16,224)	633,809
Change in cash and cash equivalents	$ 9,023	$ (4,128)	$ 6,041

Operating activities. Cash flows from operating activities increased by $51.3 million for the year ended December 31, 2013 largely as result of the Red Rock Drop Down, an increase in volumes on the DFW Midstream system and the contribution from the Bison Midstream and Mountaineer Midstream systems, partially offset by a decline in volumes on the Grand River system.

Cash flows from operating activities increased by $49.5 million during the year ended December 31, 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.

Investing activities. Cash flows used in investing activities for the year ended December 31, 2013 were largely due to the Red Rock Drop Down and the acquisitions of the Bison Midstream and Mountaineer Midstream systems. Additional expenditures in 2013 reflect the construction of new gathering pipeline across the DFW Midstream system and the acquisition of previously leased compression assets on the Grand River system. We also commissioned a new compressor unit on the DFW Midstream system in January 2013. Development activities also included construction projects to connect new receipt points on the Bison Midstream and DFW Midstream systems and to expand compression capacity on the Bison Midstream system. We also constructed a new natural gas treating facility on the DFW Midstream system, which was commissioned in February 2014.

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 acquisition of the Grand River system and reflect construction of new pipeline infrastructure to connect new pad sites on our DFW Midstream system.

Financing activities. Details of cash flows provided by (used in) financing activities for the three-year period ended December 31, 2013, were as follows:

	Year ended December 31,		
	2013	2012	2011
	(In thousands)		
Cash flows from financing activities:			
Distributions to unitholders	$ (90,196)	$ —	$ —
Borrowings under revolving credit facility	380,950	213,000	147,000
Repayments under revolving credit facility	(294,180)	(160,770)	—
Issuance of senior notes	300,000	—	—
Contribution from SMP Holdings to Bison Midstream	2,229	—	—
Issuance of units in connection with the Mountaineer Acquisition	100,000	—	—
Repurchase of DFW Net Profits Interests	(11,957)	—	—
Deferred loan costs and initial public offering costs	(10,608)	(3,344)	(5,248)
Cash advance from Summit Investments to contributed subsidiaries, net	738	500	—
Expenses paid by Summit Investments on behalf of Red Rock Gathering	10,149	2,536	—
RRG cash contributed by Summit Investments	—	1,097	—
Proceeds from issuance of common units, net	—	263,125	—
(Repayment of) proceeds from promissory notes payable to Sponsors	—	(209,230)	200,000
Distributions to Sponsors	—	(123,138)	(132,943)
Contributions from Sponsors	—	—	425,000
Net cash provided by (used in) financing activities	$ 387,125	$ (16,224)	$ 633,809

Net cash used in financing activities for the year ended December 31, 2013 was primarily composed of the following:

- Distributions declared in respect of the fourth quarter of 2012 (paid in the first quarter of 2013) and the first, second, and third quarters of 2013 (see Note 6 to the audited consolidated financial statements);
- Borrowings of $381.0 million under our revolving credit facility, of which $200.0 million was used to partially fund the Bison Drop Down and $110.0 million was used to partially fund the Mountaineer Acquisition (see Notes 5, 6 and 13 to the audited consolidated financial statements);
- Net proceeds of $294.2 million from our issuance of $300.0 million senior notes, all of which was used to pay down our revolving credit facility. In addition, we incurred loan costs in connection with the senior notes issued in June 2013 and in connection with the amendment and restatement of our revolving credit facility in November 2013 (see Notes 2 and 5 to the audited consolidated financial statements);
- Issuance of $98.0 million of common units and $2.0 million of general partner interests to affiliates for cash to partially fund the Mountaineer Acquisition (see Notes 6 and 13 to the audited consolidated financial statements); and
- Our repurchase of the remaining vested DFW Net Profits Interests (see Notes 8 and 11 to the audited consolidated financial statements).

Net cash used in financing activities for the year ended December 31, 2012 was primarily composed of the following:

- Borrowings of $163.0 million under the revolving credit facility in May 2012, of which we used $160.0 million to prepay principal amounts outstanding under certain unsecured promissory notes payable to the Sponsors and borrowings of $50.0 million in July 2012, of which we used $49.2 million to repay the balance of the unsecured promissory notes payable to the Sponsors (see Notes 5 and 10 to the audited consolidated financial statements); and
- 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 (see Note 1 to the audited consolidated financial statements); and

Net cash used in financing activities for the year ended December 31, 2011 was primarily composed of the following:

- Proceeds of $200.0 million from the execution of promissory notes payable to the Sponsors to fund a portion of the purchase of the Grand River system (see Note 10 to the audited consolidated financial statements);
- Contributions of $410.0 million 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 (see Note 13 to the audited consolidated financial statements); and
- Distributions to Energy Capital Partners of $132.9 million out of the $147.0 million drawn on the revolving credit facility (see Note 5 to the audited consolidated financial statements).

Contractual Obligations

The table below summarizes our contractual obligations and other commitments as of December 31, 2013:

	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
			(In thousands)		
Long-term debt and interest payments (1)	$ 807,663	$ 30,974	$ 61,947	$ 347,242	$ 367,500
Operating leases (2)	5,618	1,365	2,628	1,625	—
Purchase obligations (3)	17,334	17,334	—	—	—
Total contractual obligations	$ 830,615	$ 49,673	$ 64,575	$ 348,867	$ 367,500

(1) For the purpose of calculating future interest on the revolving credit facility, assumes no change in balance or rate from December 31, 2013. Includes a 0.375% commitment fee on the unused portion of the revolving credit facility. See Note 5 to the audited consolidated financial statements for additional information.
(2) See Note 12 to the audited consolidated financial statements for additional information.
(3) Represents agreements to purchase goods or services that are enforceable and legally binding.

Capital Requirements

Our 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,		
	2013	2012	2011
		(In thousands)	
Capital expenditures	$ 109,376	$ 77,296	$ 78,248
Acquisitions of gathering systems (1)	458,914	—	589,462

(1) Reflects cash paid and value of units issued to fund acquisitions.

For the year ended December 31, 2013, development activities were primarily related to pipeline construction projects to connect new natural gas receipt points and to expand compression capacity across the our gas gathering systems. Capital expenditures also reflect the acquisition of previously leased compression assets for our Grand River system in the first quarter of 2013.

For the year ended December 31, 2012, 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.

For the year ended December 31, 2011, capital expenditures largely reflect the construction of new pipeline infrastructure to connect new pad sites on our 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. As a result, our calculation of distributable cash flow reflects an estimate for the portion of these expenditures that were maintenance capital expenditures in 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 our partnership agreement, we expect to distribute to 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, non-distributed cash flow generated from operations, borrowings under the 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 Energy Capital Partners and GE Energy Financial Services to satisfy our capital expenditure requirements.

Details of cash distributions declared follow.

Attributable to the quarter ended	Payment date	Per-unit distribution	Cash paid (or payable) to common unitholders	Cash paid (or payable) to subordinated unitholders	Cash paid (or payable) to general partner [1]	Total distribution
			(Dollars in thousands, except per-unit amounts)			
December 31, 2012	February 14, 2013	$ 0.410	$ 10,009	$ 10,008	$ 408	$ 20,425
March 31, 2013	May 15, 2013	0.420	10,253	10,252	418	20,923
June 30, 2013	August 14, 2013	0.435	12,647	10,618	475	23,740
September 30, 2013	November 14, 2013	0.460	13,377	11,229	502	25,108
December 31, 2013	February 14, 2014	0.480	13,958	11,717	691	26,366

(1) Distributions attributable to the quarter ended December 31, 2013 include payments associated with the general partner's IDRs, which totaled $163,000. Our general partner was not entitled to receive incentive distributions for periods prior to the fourth quarter of 2013.

See Note 6 to the audited consolidated financial statements for additional information.

Credit Risk and Customer Concentration

We examine the creditworthiness of counterparties 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 two producer customers. For additional information, see Note 9 to the audited consolidated financial statements.

Off-Balance Sheet Arrangements

We had no off-balance sheet arrangements as of or during the year ended December 31, 2013.

Critical Accounting Policies and Estimates

We prepare our financial statements in accordance with GAAP. These principles are established 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 revenue. 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, 2013, we had net property, plant and equipment with a carrying value of approximately $1.2 billion and net intangible assets with a carrying value of approximately $502.2 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 flows. During the three-year period ended December 31, 2013, we concluded that none of our long-lived assets had been impaired.

For additional information, see Notes 2, 3 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, 2013, goodwill totaled $115.9 million.

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, 2013. Our impairment assessment involved significant estimates and judgments in developing enterprise values for: (i) the Grand River Gathering reporting unit (acquired in October 2011), (ii) the Bison Midstream reporting unit (acquired in June 2013 from SMP Holdings which acquired the underlying gas gathering system in February 2013) and (iii) the Mountaineer Midstream reporting unit (acquired in June 2013) to complete step one of the goodwill impairment assessment. Furthermore, because Bison Midstream was acquired from SMP Holdings and as such a transaction among entities under common control, we recognized the acquisition of the Bison Midstream gathering system at historical cost which reflected the fair value accounting recognized in connection with its February 2013 acquisition. To estimate the enterprise values of Grand River and Bison Midstream, we utilized two valuation methodologies: the market approach and the income approach. The most significant estimates and judgments inherent within these two valuation methodologies were: (i) selection of the discount rate, (ii) guideline public companies, (iii) market multiples, (iv) control premium, (v) growth rates, and (vi) the expected levels of throughput volume gathered on the Grand River and Bison Midstream systems. In estimating the fair value of Mountaineer Midstream, we evaluated changes in internal and external market evidence during the period from the June 21, 2013 acquisition date through September 30, 2013 and concluded that the purchase price paid approximated the enterprise value of the Mountaineer Midstream reporting unit as of September 30, 2013. As a result of our assessments, we determined that no factors existed which would lead us to conclude that an impairment of goodwill was necessary for any of these three reporting units as of September 30, 2013. Furthermore, we do not believe that any events or circumstances have occurred since our annual impairment analysis that would require an interim impairment test nor do we presently believe that the reporting units of these three systems are at risk of failing step one. Prior to the acquisition of Grand River Gathering, the Predecessor had no goodwill. There is no goodwill associated with the DFW Midstream reporting unit.

For additional information, see Notes 2, 4 and 13 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, 2013, we had MVCs totaling 4.2 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, 2013, we had current deferred revenue totaling approximately $1.6 million and noncurrent deferred revenue totaling approximately $29.7 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.

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. In April 2013, we purchased the remaining net profits interests in DFW Midstream. Subsequent to the IPO, the Partnership's financial statements do not reflect the net profits interests in Summit Midstream Management, LLC as they were retained by the Predecessor except for the portion of expense that was allocated to Red Rock Gathering for the year ended December 31, 2013. We refer to these Class B membership 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. We accounted for the net profits interests as compensatory awards. The net profits interest vest ratably over four to five years (as defined in the underlying agreements), and provided for accelerated vesting in certain limited circumstances, including a qualifying termination following a change in control (as defined in the underlying agreements). 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 modeled the Class A and Class B membership interests as call options on the underlying enterprise equity value and considered 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:

- 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;
- holding period restrictions;
- discounts for lack of marketability; and
- 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 8 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 $2.5 million for the year ended December 31, 2013.

Commodity Price Risk

We currently generate a substantial majority of our revenues pursuant to long-term, primarily fee-based gas gathering agreements, many of which include MVCs and areas of mutual interest. Our 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, (iii) the sale of condensate volumes that we retain on the Grand River system and (iv) the sale of processed natural gas and natural gas liquids pursuant to our processing contracts with certain of our customers on the Bison Midstream and Grand River systems. Our gas gathering agreements with our DFW Midstream 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.

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, 2013 and 2012, 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, 2013. 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, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America.

The consolidated financial statements give retrospective effect to the Partnership’s acquisition of Bison Midstream, LLC from Summit Midstream Partners Holdings, LLC, as a combination of entities under common control, which has been accounted for in a manner similar to a pooling of interests, as described in Notes 1 and 13 to the consolidated financial statements.

The consolidated financial statements also give retrospective effect to the Partnership’s acquisition of Red Rock Gathering Midstream, LLC from a subsidiary of Summit Midstream Partners, LLC, as a combination of entities under common control, which has been accounted for in a manner similar to a pooling of interests, as described in Notes 1 and 13 to the consolidated financial statements.

The Partnership acquired the Mountaineer Midstream gathering system on June 21, 2013 and Grand River Gathering Company, LLC on October 27, 2011, as described in Note 13 to the consolidated financial statements.

/s/ Deloitte & Touche LLP

Dallas, Texas
March 10, 2014
(July 3, 2014 as to Note 1)

SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2013	December 31, 2012
	(Dollars in thousands)	
Assets		
Current assets:		
Cash and cash equivalents	$ 20,357	$ 11,334
Accounts receivable	67,877	43,668
Due from affiliate	—	774
Other assets	4,741	3,339
Total current assets	92,975	59,115
Property, plant and equipment, net	1,158,081	832,602
Intangible assets, net:		
Favorable gas gathering contracts	17,880	19,958
Contract intangibles	383,306	229,596
Rights-of-way	100,991	87,894
Total intangible assets, net	502,177	337,448
Goodwill	115,888	45,478
Other noncurrent assets	14,618	6,296
Total assets	$ 1,883,739	$ 1,280,939
Liabilities and Partners' Capital		
Current liabilities:		
Trade accounts payable	$ 25,117	$ 18,697
Due to affiliate	653	—
Deferred revenue	1,555	865
Ad valorem taxes payable	8,375	8,302
Accrued interest	12,144	16
Other current liabilities	11,729	5,007
Total current liabilities	59,573	32,887
Long-term debt	586,000	199,230
Noncurrent liability, net (Note 4)	6,374	7,420
Deferred revenue	29,683	10,899
Other noncurrent liabilities	372	255
Total liabilities	682,002	250,691
Commitments and contingencies (Note 12)		
Common limited partner capital (29,079,866 units issued and outstanding at December 31, 2013 and 24,412,427 units issued and outstanding at December 31, 2012)	566,532	418,856
Subordinated limited partner capital (24,409,850 units issued and outstanding at December 31, 2013 and 2012)	379,287	380,169
General partner interests (1,091,453 units issued and outstanding at December 31, 2013 and 996,320 issued and outstanding at December 31, 2012)	23,324	20,222
Summit Investments' equity in contributed subsidiaries	232,594	211,001
Total partners' capital	1,201,737	1,030,248
Total liabilities and partners' capital	$ 1,883,739	$ 1,280,939

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

SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year ended December 31,		
	2013	2012	2011
	(In thousands, except per-unit and unit amounts)		
Revenues:			
Gathering services and other fees	$ 205,346	$ 154,139	$ 91,421
Natural gas, NGLs and condensate sales and other	88,606	20,476	12,439
Amortization of favorable and unfavorable contracts	(1,032)	(192)	(308)
Total revenues	292,920	174,423	103,552
Costs and expenses:			
Operation and maintenance	72,465	53,882	29,855
Cost of natural gas and NGLs	44,233	3,224	—
General and administrative	30,105	22,182	17,476
Transaction costs	2,841	2,025	3,166
Depreciation and amortization	69,962	36,674	11,367
Total costs and expenses	219,606	117,987	61,864
Other (expense) income	(108)	9	12
Interest expense	(19,173)	(7,340)	(1,029)
Affiliated interest expense	—	(5,426)	(2,025)
Income before income taxes	54,033	43,679	38,646
Income tax expense	(729)	(682)	(695)
Net income	$ 53,304	$ 42,997	$ 37,951
Less: net income attributable to the pre-IPO period (Note 1)	—	24,112	
Less: net income attributable to SMP Holdings (Note 1)	9,720	1,271	
Net income attributable to SMLP	43,584	17,614	
Less: net income attributable to general partner, including IDRs	1,035	352	
Net income attributable to limited partners	$ 42,549	$ 17,262	
Earnings per limited partner unit (Note 7):			
Common unit – basic	$ 0.86	$ 0.35	
Common unit – diluted	$ 0.86	$ 0.35	
Subordinated unit – basic and diluted	$ 0.79	$ 0.35	
Weighted-average limited partner units outstanding:			
Common units – basic	26,951,346	24,412,427	
Common units – diluted	27,101,479	24,543,985	
Subordinated units – basic and diluted	24,409,850	24,409,850	

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

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

	Partners' capital					
	Limited partners					
	Common	Subordinated	General partner	SMP Holdings' equity in contributed subsidiaries	Membership interests	Total
	(In thousands)					
Membership interests, January 1, 2011	$ —	$ —	$ —	$ —	$ 307,370	$ 307,370
Net income	—	—	—	—	37,951	37,951
Class B membership interest unit-based compensation	—	—	—	—	3,440	3,440
Contributions from Sponsors	—	—	—	—	425,000	425,000
Distribution of cash to Sponsors	—	—	—	—	(132,943)	(132,943)
Membership interests, December 31, 2011	—	—	—	—	640,818	640,818
Net income	8,631	8,631	352	1,271	24,112	42,997
SMLP unit-based compensation	269	—	—	—	—	269
Class B membership interest 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)
Consolidation of Red Rock Gathering net assets	—	—	—	206,694	—	206,694
Cash advance from Summit Investments to contributed subsidiaries, net	—	—	—	500	—	500
Expenses paid by Summit Investments on behalf of contributed subsidiaries	—	—	—	2,536	—	2,536
Partners' capital, December 31, 2012	418,856	380,169	20,222	211,001	—	1,030,248
Net income	22,311	20,238	1,035	9,720	—	53,304
SMLP unit-based compensation	2,999	—	—	—	—	2,999
Consolidation of Bison Midstream net assets	—	—	—	303,168	—	303,168
Contribution from SMP Holdings to Bison Midstream	—	—	—	2,229	—	2,229
Purchase of Bison Midstream	47,936	—	978	(248,914)	—	(200,000)
Contribution of net assets from SMP Holdings in excess of consideration paid for Bison Midstream	28,558	26,846	1,131	(56,535)	—	—
Issuance of units in connection with the Mountaineer Acquisition	98,000	—	2,000	—	—	100,000

Class B membership interest unit-based compensation	17	—	—	490	—	507
Repurchase of DFW Net Profits Interests	(5,859)	(5,859)	(239)	—	—	(11,957)
Distributions to unitholders	(46,286)	(42,107)	(1,803)	—	—	(90,196)
Cash advance from Summit Investments to contributed subsidiaries, net	—	—	—	738	—	738
Capitalized interest allocated to Red Rock Gathering projects from SMP Holdings	—	—	—	496	—	496
Expenses paid by Summit Investments on behalf of contributed subsidiaries	—	—	—	10,149	—	10,149
Capital expenditures paid by Summit Investments on behalf of Red Rock Gathering	—	—	—	52	—	52
Partners' capital, December 31, 2013	$ 566,532	$ 379,287	$ 23,324	$ 232,594	$ —	$ 1,201,737

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

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

	Year ended December 31,		
	2013	2012	2011
	(In thousands)		
Cash flows from operating activities:			
Net income	$ 53,304	$ 42,997	$ 37,951
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	70,994	36,866	11,675
Amortization of deferred loan costs	2,246	1,458	560
Unit-based compensation	3,506	1,876	3,440
Loss on asset sales	113	—	—
Pay-in-kind interest on promissory notes payable to Sponsors	—	5,426	2,025
Changes in operating assets and liabilities:			
Accounts receivable	(18,605)	(8,174)	(17,238)
Due to/from affiliate	1,427	(773)	—
Trade accounts payable	(3,419)	(2,536)	2,468
Change in deferred revenue	16,685	9,994	—
Ad valorem taxes payable	(11)	3,125	—
Accrued interest	12,128	(484)	500
Other, net	2,321	(383)	(1,439)
Net cash provided by operating activities	140,689	89,392	39,942
Cash flows from investing activities:			
Capital expenditures	(109,376)	(77,296)	(78,248)
Proceeds from asset sales	585	—	—
Acquisition of gathering systems	(210,000)	—	(589,462)
Acquisition of gathering system from affiliate	(200,000)	—	—
Net cash used in investing activities	(518,791)	(77,296)	(667,710)

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

	Year ended December 31,		
	2013	2012	2011
	(In thousands)		
Cash flows from financing activities:			
Distributions to unitholders	$ (90,196)	$ —	$ —
Borrowings under revolving credit facility	380,950	213,000	147,000
Repayments under revolving credit facility	(294,180)	(160,770)	—
Issuance of senior notes	300,000	—	—
Contribution from SMP Holdings to Bison Midstream	2,229	—	—
Issuance of units to affiliate in connection with the Mountaineer Acquisition	100,000	—	—
Repurchase of DFW Net Profits Interests	(11,957)	—	—
Deferred loan costs	(10,608)	(3,344)	(5,248)
(Repayment of) proceeds from promissory notes payable to Sponsors	—	(209,230)	200,000
Proceeds from issuance of common units	—	263,125	—
Cash advance from Summit Investments to contributed subsidiaries, net	738	500	—
Expenses paid by Summit Investments on behalf of Red Rock Gathering	10,149	2,536	—
Red Rock Gathering cash contributed by Summit Investments	—	1,097	—
Distributions to Sponsors	—	(123,138)	(132,943)
Contributions from Sponsors	—	—	425,000
Net cash provided by (used in) financing activities	387,125	(16,224)	633,809
Net change in cash and cash equivalents	9,023	(4,128)	6,041
Cash and cash equivalents, beginning of period	11,334	15,462	9,421
Cash and cash equivalents, end of period	$ 20,357	$ 11,334	$ 15,462
Supplemental Cash Flow Disclosures:			
Cash interest paid	$ 9,016	$ 8,283	$ 2,463
Less: capitalized interest	4,705	2,784	3,362
Interest paid (net of capitalized interest)	$ 4,311	$ 5,499	$ (899)
Cash paid for income taxes	$ 660	$ 650	$ 223
Noncash Investing and Financing Activities:			
Capital expenditures in trade accounts payable (period-end accruals)	$ 16,470	$ 8,523	$ 11,332
Issuance of units to affiliate to partially fund the Bison Drop Down	48,914	—	—
Contribution of net assets from SMP Holdings in excess of consideration paid for Bison Midstream	56,535	—	—
Capitalized interest allocated to Red Rock Gathering projects from SMP Holdings	496	—	—
Capital expenditures paid by Summit Investments on behalf of Red Rock Gathering	52	—	—
Pay-in-kind interest on promissory notes payable to Sponsors	—	6,337	2,893
Net assets retained by the Predecessor	—	4,417	—
Deferred initial public offering costs in trade accounts payable	—	743	—
Working capital acquired related to Grand River system acquisition	—	—	854

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

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

1. ORGANIZATION, BUSINESS OPERATIONS AND BASIS OF PRESENTATION

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 developing, 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.

Effective with the completion of its IPO on October 3, 2012, SMLP has a 100% ownership interest in Summit Midstream Holdings, LLC ("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. For additional information, see "—Initial Public Offering" below.

On June 4, 2013, Summit Holdings acquired all of the membership interests of Bison Midstream, LLC ("Bison Midstream") from Summit Midstream Partners Holdings, LLC ("SMP Holdings"), a wholly owned direct subsidiary of Summit Midstream Partners, LLC ("Summit Investments") (the "Bison Drop Down"), and thereby acquired certain associated natural gas gathering pipeline, dehydration and compression assets in the Bakken Shale Play in Mountrail and Burke counties in North Dakota (the "Bison Gas Gathering system").

Prior to the Bison Drop Down, on February 15, 2013, Summit Investments acquired Bear Tracker Energy, LLC ("BTE") and subsequently contributed it to SMP Holdings. The Bison Gas Gathering system was carved out from BTE in connection with the Bison Drop Down. As such, it was deemed a transaction among entities under common control. For additional information, see Notes 5, 6 and 13.

On June 21, 2013, Mountaineer Midstream Company, LLC ("Mountaineer Midstream"), a newly formed, wholly owned subsidiary of Summit Holdings, acquired certain natural gas gathering pipeline and compression assets in the Marcellus Shale Play in Doddridge County, West Virginia from an affiliate of MarkWest Energy Partners, L.P. ("MarkWest") (the "Mountaineer Acquisition"). In December 2013, Mountaineer Midstream was merged into DFW Midstream. For additional information, see Notes 5, 6 and 13.

In October 2012, Summit Investments acquired ETC Canyon Pipeline, LLC ("Canyon") from a subsidiary of Energy Transfer Partners, L.P. ("Energy Transfer Partners"). The Canyon gathering and processing assets were contributed to Red Rock Gathering Company, LLC ("Red Rock Gathering"), a newly formed, wholly owned subsidiary of Summit Investments. Red Rock Gathering gathers and processes natural gas and natural gas liquids in the Piceance Basin in western Colorado and eastern Utah. On March 18, 2014, SMLP acquired all of the membership interests of Red Rock Gathering from a subsidiary of Summit Investments (the "Red Rock Drop Down"). Concurrent with the closing of the Red Rock Drop Down, SMLP contributed its interest in Red Rock Gathering to Grand River Gathering. For additional information, see Notes 6 and 13.

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 in September 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"). In March 2013, Summit Investments contributed the ownership of its SMLP common and subordinated units along with its 2% general partner interest in SMLP to SMP Holdings in exchange for a continuing 100% interest in SMP Holdings. As of December 31, 2013, SMP Holdings held 14,691,397 SMLP common units, 24,409,850 SMLP subordinated units and 1,091,453 general partner units representing a 2% general partner interest in SMLP.

SMLP is managed and operated by the board of directors and executive officers of Summit Midstream GP, LLC (the "general partner"). Summit Investments, as the ultimate owner of our general partner, controls SMLP 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 has 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.

Business Operations. We provide natural gas gathering, treating and processing services pursuant to long-term, primarily fee-based, natural gas gathering agreements with our customers. Our results are driven primarily by the volumes of natural gas that we gather, treat and process across our systems. Our gathering systems and the unconventional resource basins in which they operate as of December 31, 2013 were as follows:

- Mountaineer Midstream – the Appalachian Basin, which includes the Marcellus Shale formation in northern West Virginia;
- Bison Midstream – the Williston Basin, which includes the Bakken and Three Forks shale formations in northwestern North Dakota;
- DFW Midstream – the Fort Worth Basin, which includes the Barnett Shale formation in north-central Texas; and
- Grand River Gathering – the Piceance Basin, which includes the Mesaverde formation and the Mancos and Niobrara shale formations in western Colorado and eastern Utah.

Our operating subsidiaries are DFW Midstream (which includes the Mountaineer Midstream gathering system), Bison Midstream and Grand River Gathering. All of our operating 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.

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 the disclosure of contingencies. Although management believes these estimates are reasonable, actual results could differ from its estimates.

For the purposes of the 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 also reflect the results of operations of: (i) Red Rock Gathering since October 23, 2012, (ii) Bison Midstream since February 16, 2013 and (iii) Mountaineer Midstream since June 22, 2013. SMLP recognized its acquisitions of Red Rock Gathering and Bison Midstream at Summit Investments' historical cost because the acquisitions were executed by entities under common control. The excess of the purchase price paid by SMLP over Summit Investments' net investment in Red Rock Gathering was recognized as a reduction to partners' capital. The excess of Summit Investments' net investment in Bison Midstream over the purchase price paid by SMLP was recognized as an addition to partners' capital. Due to the common control aspect, the Red Rock Drop Down and the Bison Drop Down were accounted for by the Partnership on an “as if pooled” basis for the periods during which common control existed. See Notes 5, 6 and 13 for additional information. The consolidated financial statements include the assets, liabilities, and results of operations of SMLP or the Predecessor and their respective wholly owned subsidiaries. All intercompany transactions among the consolidated entities have been eliminated in consolidation. These consolidated financial statements have been retrospectively updated solely to reflect the impact of the Red Rock Drop Down; subsequent events have not been updated beyond March 10, 2014, the date the consolidated financial statements were initially issued and filed with the Securities and Exchange Commission.

We conduct our operations in the midstream sector with four operating segments: Mountaineer Midstream, Bison Midstream, DFW Midstream and Grand River Gathering. However, due to their similar characteristics and how we manage our business, we have aggregated these segments into one reportable segment for disclosure purposes. The assets of our reportable segment consist of natural gas gathering systems and related plant and equipment. Our operating segments reflect the way in which we internally report the financial information used to make decisions and allocate resources in connection with our operations.

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 and other counterparties. To the extent we doubt the collectability of our accounts receivable, we recognize an allowance for doubtful accounts. We did not experience any non-payments during the three-year period ended December 31, 2013. As a result, we did not recognize an allowance for doubtful accounts as of December 31, 2013 and 2012.

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 an expense as incurred. We capitalize project costs incurred during construction, including interest on funds borrowed to finance the construction of facilities, as construction in progress. Prior to the Red Rock Drop Down, SMP Holdings incurred interest expense related to certain Red Rock Gathering capital projects. The associated interest expense was allocated to Red Rock Gathering as a noncash equity contribution and capitalized into the basis of the asset.

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, 2013 and 2012, we evaluated whether any future asset retirement obligations existed. For identified asset retirement obligations, we then evaluated whether the expected retirement date and the related costs of retirement could be estimated. In performing this evaluation, we concluded that our natural gas gathering and processing 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, 2013 or 2012.

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 our other 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, 2013, 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.

Other Noncurrent Assets. Other noncurrent assets primarily consist of external costs incurred in connection with the issuance of our senior notes and the closing of our revolving credit facility and related amendments. We capitalize and then amortize these deferred loan costs over the life of the respective debt instrument. We recognize amortization of deferred loan costs in interest expense.

Derivative Contracts. We have commodity price exposure related to our sale of the physical natural gas we retain from our DFW customers, and our procurement of electricity to operate our electric-drive compression assets on the DFW Midstream system. Our gas gathering agreements with our DFW Midstream customers permit us to retain a certain quantity of natural gas that we gather to offset the power costs we incur to operate our electric-drive compression assets. We manage this 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 retainage sales.

Accounting standards related to derivative instruments and hedging activities allow for "normal" purchase or sale elections and hedge accounting designations, which generally eliminate or defer the requirement for mark-to-market recognition in net income and thus reduce the volatility of net income that can result from fluctuations in fair values. We have designated these contracts as normal under the normal purchase and sale exception under the accounting standards for derivatives. We do not enter into risk management contracts for speculative purposes.

Fair Value of Financial Instruments. The carrying amount of cash and cash equivalents (Level 1), accounts receivable, and accounts payable reported on the balance sheet approximates fair value due to their short-term maturities.

GAAP's fair-value-measurement standard defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The standard characterizes inputs used in determining fair value according to a hierarchy that prioritizes those inputs based upon the degree to which they are observable. The three levels of the fair value hierarchy are as follows:

- ***Level 1.*** Inputs represent quoted prices in active markets for identical assets or liabilities;
- ***Level 2.*** Inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly (for example, quoted market prices for similar assets or liabilities in active markets or quoted market prices for identical assets or liabilities in markets not considered to be active, inputs other than quoted prices that are observable for the asset or liability, or market-corroborated inputs); and
- ***Level 3.*** Inputs that are not observable from objective sources, such as management’s internally developed assumptions used in pricing an asset or liability (for example, an estimate of future cash flows used in management’s internally developed present value of future cash flows model that underlies the fair value measurement).

Nonfinancial assets and liabilities initially measured at fair value include those acquired and assumed in connection with third-party business combinations.

A summary of the estimated fair value for financial instruments follows.

	December 31, 2013		December 31, 2012	
	Carrying value	Estimated fair value (Level 2)	Carrying value	Estimated fair value (Level 2)
	(In thousands)			
Revolving credit facility	$ 286,000	$ 286,000	$ 199,230	$ 199,230
Senior notes	300,000	314,625	—	—

The revolving credit facility’s carrying value on the balance sheet is its fair value due to its floating interest rate. The fair value for the senior notes is based on an average of nonbinding broker quotes as of December 31, 2013. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value of the senior notes.

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 generate the majority of our revenue from the natural gas gathering, treating and processing services that we provide to our natural gas producer customers. We also generate revenue from our marketing of natural gas and natural gas liquids ("NGLs"). We realize revenues by receiving fees from our producer customers or by selling the residue natural gas and NGLs.

We recognize revenue earned from fee-based gathering, treating and processing services in gathering services and other fees revenue. We also earn revenue from the sale of physical natural gas purchased from our customers under percentage-of-proceeds and keep-whole arrangements. These revenues are recognized in natural gas, NGLs and condensate sales and other with corresponding expense recognition in cost of natural gas and NGLs. 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 also sell condensate retained from our gathering services at Grand River Gathering. Revenues from the retainage of natural gas and condensate are recognized in natural gas, NGLs and condensate sales and other; the associated expense is included in operation and maintenance expense. Certain customers reimburse us for costs we incur on their behalf. We record costs incurred and reimbursed by our customers on a gross basis.

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 obtain access to natural gas and provide services principally under contracts that contain one or more of the following arrangements:

- ***Fee-based arrangements.*** Under fee-based arrangements, we receive a fee or fees for one or more of the following services: natural gas gathering, treating and/or processing. Fee-based arrangements include natural gas purchase arrangements pursuant to which we purchase natural gas at the wellhead, or other receipt points, at a settled price at the delivery point less a specified amount, generally the same as the fees we would otherwise charge for gathering of natural gas from the wellhead location to the delivery point. The margins earned are directly related to the volume of natural gas that flows through the system.
- ***Percent-of-proceeds arrangements.*** Under percent-of-proceeds arrangements, we generally purchase natural gas from producers at the wellhead, or other receipt points, gather the wellhead natural gas through our gathering system, treat the natural gas, process the natural gas and/or sell the natural gas to a third party for processing. We then remit to our producers an agreed-upon percentage of the actual proceeds received from sales of the residue natural gas and NGLs. Certain of these arrangements may also result in returning all or a portion of the residue natural gas and/or the NGLs to the producer, in lieu of returning sales proceeds. The margins earned are directly related to the volume of natural gas that flows through the system and the price at which we are able to sell the residue natural gas and NGLs.
- ***Keep-Whole.*** Under keep-whole arrangements, after processing we keep 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, we compensate the producer for the amount of natural gas used and removed in processing by supplying additional natural gas or by paying an agreed-upon value for the natural gas utilized. These arrangements have commodity price exposure for us because the costs are dependent on the price of natural gas and the revenues are based on the price of NGLs.

Certain of our natural gas gathering agreements provide for a monthly, quarterly or annual minimum volume commitment ("MVC") from certain of our customers. Under these 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 period if its actual throughput volumes are less than its MVC for that period. 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.

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 or processing 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 or processing 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 current for arrangements where the expiration of a customer's right to utilize shortfall payments is twelve months or less. A rollforward of current and noncurrent deferred revenue follows.

	Current	Noncurrent
	(In thousands)	
Deferred revenue, January 1, 2012	$ —	$ 1,770
Additions	865	9,129
Deferred revenue, December 31, 2012	865	10,899
Additions (1)	1,555	18,784
Less: revenue recognized due to expiration	865	—
Deferred revenue, December 31, 2013	$ 1,555	$ 29,683

(1) Noncurrent includes amounts recognized in connection with the Bison Drop Down.

As of December 31, 2013, we have $1.1 million included in accounts receivable for shortfall payments related to MVC arrangements which can be utilized to offset gathering fees in subsequent periods. Current and noncurrent deferred revenue at December 31, 2013 includes amounts that provide the customer the ability to offset gathering fees in the next one month to eight years to the extent that the 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, in the statement of operations over the vesting period of the respective awards. See Note 8 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"). The Texas Margin Tax has the characteristics of an income tax because it is determined by applying a tax rate to a tax base that considers both revenues and expenses. Our financial statements reflect provisions for these tax obligations.

Earnings Per Unit ("EPU"). We present earnings per limited partner unit data only for periods subsequent to the closing of SMLP's IPO in October 2012. EPU for periods ended prior to the IPO have not been presented because Summit Investments' members held membership interests and not units.

We determine EPU by dividing the net income that is 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 payments to the general partner in connection with their incentive distribution rights ("IDRs"), by the weighted-average number of common and subordinated units outstanding during the year ended December 31, 2013 and 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.

Comprehensive Income. Comprehensive income is the same as net income for all periods presented.

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 material compliance with applicable environmental regulations, the risk of costs and liabilities are inherent in pipeline ownership and operation. Liabilities for loss contingencies, including environmental remediation costs, arising from claims, assessments, litigation, fines, and penalties and other sources are charged to expense when it is probable that a liability has been incurred and the amount of the assessment and/or remediation can be reasonably estimated. There are no such liabilities reflected in the accompanying financial statements at December 31, 2013 or 2012. However, we can provide no assurances that significant costs and liabilities will not be incurred by the Partnership in the future. We are currently not aware of any material contingent liabilities that 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 financial statements. There are currently no recent pronouncements that have been issued that we believe will materially affect our financial statements.

3. PROPERTY, PLANT, AND EQUIPMENT, NET

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

	Useful lives (In years)	December 31, 2013	December 31, 2012
		(Dollars in thousands)	
Gas gathering systems	30	$ 744,359	$ 544,020
Compressor stations and compression equipment	30	380,000	261,705
Construction in progress	n/a	83,765	54,582
Other	4-15	21,304	6,897
Total		1,229,428	867,204
Accumulated depreciation		(71,347)	(34,602)
Property, plant, and equipment, net		$ 1,158,081	$ 832,602

The increase in property, plant, and equipment primarily reflects the recognition of gas gathering system fixed assets acquired in connection with the Bison Drop Down and Mountaineer Acquisition. See Note 13 for additional information.

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, 2013	2012	2011
	(In thousands)		
Depreciation expense	$ 36,745	$ 22,422	$ 8,595
Capitalized interest	4,705	2,784	3,362

4. IDENTIFIABLE INTANGIBLE ASSETS, NONCURRENT LIABILITY AND GOODWILL

Identifiable Intangible Assets and Noncurrent Liability. Identifiable intangible assets and the noncurrent liability, which are subject to amortization, were as follows:

	Useful lives (In years)	Gross carrying amount	Accumulated amortization	Net
	December 31, 2013 (Dollars in thousands)			
Favorable gas gathering contracts	18.7	$ 24,195	$ (6,315)	$ 17,880
Contract intangibles	12.5	426,464	(43,158)	383,306
Rights-of-way	24.3	108,706	(7,715)	100,991
Total amortizable intangible assets		$ 559,365	$ (57,188)	$ 502,177
Unfavorable gas gathering contract	10.0	$ 10,962	$ (4,588)	$ 6,374

	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	23.5	91,046	(3,152)	87,894
Total amortizable intangible assets		$ 359,341	$ (21,893)	$ 337,448
Unfavorable gas gathering contract	10.0	$ 10,962	$ (3,542)	$ 7,420

The increase in total amortizable intangible assets primarily reflects the recognition of gas gathering contracts and rights-of-way acquired in connection with the Bison Drop Down and the Mountaineer Acquisition. See Note 13 for additional information.

We recognized amortization expense as follows:

	Year ended December 31,		
	2013	2012	2011
	(In thousands)		
Amortization expense – favorable gas gathering contracts	$ 2,078	$ 1,715	$ 1,718
Amortization expense – contract intangibles	28,654	12,642	1,862
Amortization expense – rights-of-way	4,563	1,610	908
Amortization expense – unfavorable gas gathering contract	(1,046)	(1,524)	(1,410)

The estimated aggregate annual amortization of intangible assets and noncurrent liability expected to be recognized as of December 31, 2013 for each of the five succeeding fiscal years follows.

	Assets	Liabilities
	(In thousands)	
2014	$ 40,503	$ 1,549
2015	43,522	1,650
2016	43,777	1,571
2017	42,513	1,604
2018	42,058	—

Goodwill. We recognized goodwill of $45.5 million in connection with the acquisition of Grand River Gathering in 2011 and allocated it to the Grand River Gathering reporting unit. We recognized goodwill of $54.2 million in connection with the Bison Drop Down in June 2013 and allocated it to the Bison Midstream reporting unit. The goodwill attributed to Bison Midstream represents its allocation of the goodwill that Summit Investments recognized in connection with its acquisition of BTE assets in February 2013. We preliminarily recognized goodwill of $18.1 million in connection with the Mountaineer Acquisition in June 2013 and allocated it to the Mountaineer Midstream reporting unit. Prior to the issuance of the financial statements, we received the remaining information needed to finalize accounting for the Mountaineer Acquisition and recognized an adjustment, which reduced the preliminary goodwill recognition by $1.9 million. See Notes 1 and 13 for additional information. A rollforward of the consolidated balance of goodwill follows (in thousands).

Goodwill, December 31, 2012 and 2011	$ 45,478
Goodwill recognized in connection with the Bison Drop Down	54,199
Goodwill preliminarily recognized in connection with the Mountaineer Acquisition	18,089
Goodwill adjustment recognized in connection with finalizing accounting for the Mountaineer Acquisition and other	(1,878)
Goodwill, December 31, 2013	$ 115,888

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 performed our annual goodwill impairment testing as of September 30, 2013 using a combination of the income and market approaches and determined that the fair value of each of these three reporting units exceeded its carrying value resulting in no goodwill impairment. There have been no impairments of goodwill and there is no goodwill associated with the DFW Midstream reporting unit.

5. LONG-TERM DEBT

Long-term debt consisted of the following:

	December 31,	
	2013	2012
	(In thousands)	
Variable rate senior secured revolving credit facility (2.42% at December 31, 2013 and 2.98% at December 31, 2012) due November 2018	$ 286,000	$ 199,230
7.50% Senior unsecured notes due July 2021	300,000	—
Total long-term debt	$ 586,000	$ 199,230

Revolving Credit Facility. We have a senior secured revolving credit facility. In June 2013, we exercised the revolving credit facility's $50.0 million accordion provision and increased the total commitments thereunder from $550.0 million to $600.0 million. We also borrowed $200.0 million in connection with the Bison Drop Down and $110.0 million in connection with the Mountaineer Acquisition. See Notes 1, 6 and 12 for additional information. Also in June 2013, we used the proceeds from our senior notes offering to repay $294.2 million of our revolving credit facility. In November 2013, we closed on an amendment and restatement of the revolving credit facility which: (i) increased the borrowing capacity to $700.0 million, (ii) extended the maturity to November 2018, (iii) included a $200.0 million accordion feature, (iv) reduced the leverage-based pricing grid by 0.75% to a new range of 1.75% to 2.75% for LIBOR borrowings, (v) changed the commitment fee to a leverage-based range of 0.30% to 0.50%, and (vi) added Summit Midstream Finance Corp. ("Finance Corp.") as a subsidiary guarantor.

The revolving credit facility is secured by the membership interests of Summit Holdings and those of its subsidiaries. Substantially all of Summit Holdings' and its subsidiaries' assets are pledged as collateral under the revolving credit facility. The revolving credit facility, and Summit Holdings' obligations, are guaranteed by SMLP and each of its subsidiaries and allows for revolving loans, letters of credit and swingline loans.

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, 2013, the applicable margin under LIBOR borrowings was 2.25%, the interest rate was 2.42% and the unused portion of the revolving credit facility totaled $414.0 million (subject to a commitment fee of 0.375%).

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 net 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 270 days following certain acquisitions (as defined in the credit agreement).

As of December 31, 2013, we were in compliance with the covenants in the revolving credit facility. There were no defaults or events of default during the year ended December 31, 2013.

Senior Notes. On June 17, 2013, Summit Holdings and its 100% owned finance subsidiary, Finance Corp. (together with Summit Holdings, the "Co-Issuers"), issued $300.0 million of 7.50% senior unsecured notes maturing July 1, 2021 (the "senior notes"). The senior notes were sold within the United States only to qualified institutional buyers in reliance on Rule 144A under the Securities Act of 1933, as amended (the "Securities Act"), and outside the United States only to non-U.S. persons in reliance on Regulation S under the Securities Act. The senior notes have not been registered under the Securities Act or any state securities laws, and, unless so registered, may not be offered or sold in the United States except pursuant to an exemption from, or in a transaction not subject to, the registration requirements of the Securities Act and applicable state securities laws.

We will pay interest on the senior notes semi-annually in cash in arrears on January 1 and July 1 of each year, commencing January 1, 2014. The senior notes are senior, unsecured obligations and rank equally in right of payment with all of our existing and future senior obligations. The senior notes are effectively subordinated in right of payment to all of our secured indebtedness, to the extent of the collateral securing such indebtedness. We used the proceeds from the issuance of the senior notes to repay a portion of the balance outstanding under our revolving credit facility. Debt issuance costs of $7.3 million, recognized in other noncurrent assets, are being amortized over the life of the senior notes.

SMLP and all of its subsidiaries other than the Co-Issuers (the "Guarantors") have fully and unconditionally and jointly and severally guaranteed the senior notes. SMLP has no independent assets or operations. Summit Holdings has no assets or operations other than its ownership of its wholly owned subsidiaries and activities associated with its borrowings under the revolving credit facility and the senior notes. Finance Corp. has no independent assets or operations and was formed for the sole purpose of being a co-issuer of certain of Summit Holdings' indebtedness, including the senior notes. There are no significant restrictions on the ability of SMLP or Summit Holdings to obtain funds from its subsidiaries by dividend or loan.

In connection with the associated registration rights agreement, the Co-Issuers and the Guarantors agreed to file a registration statement with the SEC pursuant to which the Co-Issuers will either offer to exchange the senior notes and the guarantees for registered notes and guarantees with substantially identical terms or, in certain circumstances, register the resale of the senior notes and their guarantees (the "Exchange Offer"). In January 2014, we filed a registration statement on Form S-4 to offer to exchange all of the unregistered senior notes and guarantees for registered notes and guarantees with substantially identical terms. The terms of the registered senior notes are substantially identical to the terms of the unregistered senior notes, except that the transfer restrictions, registration rights and provisions for additional interest relating to the unregistered senior notes do not apply to the registered senior notes. On March 7, 2014, the SEC declared our registration statement effective and we began the notice process to properly effect the exchange. The period during which exchanges can occur will end on April 7, 2014. If a holder of the unregistered senior notes does not exchange them for the registered senior notes, such holder will no longer be able to require us to register their private note holdings under the Securities Act, except in limited circumstances provided under the registration rights agreement.

If the Exchange Offer is not completed (or, if required, the shelf registration statement is not declared effective or does not automatically become effective) on or before the 365th day following the date of issuance of the senior notes (the ‘‘Exchange Completion Deadline’’), the Co-Issuers will be required to pay additional interest in an amount equal to 0.25% per annum of the principal amount of senior notes with respect to the first 90-day period following the Exchange Completion Deadline. The amount of the additional interest will increase by an additional 0.25% per annum with respect to each subsequent 90-day period, up to a maximum amount of additional interest of 1.0% per annum of the principal amount of senior notes outstanding until the Exchange Offer is completed or the shelf registration statement is declared effective (or becomes automatically effective). All accrued additional interest will be paid by the Co-Issuers and the Guarantors on the next scheduled interest payment date in the same manner as other interest is paid on the senior notes. Following the time that the senior notes are registered, the accrual of additional interest will cease.

At any time prior to July 1, 2016, the Co-Issuers may redeem up to 35% of the aggregate principal amount of the senior notes at a redemption price of 107.500% of the principal amount of the senior notes, plus accrued and unpaid interest, if any, to the redemption date, with an amount not greater than the net cash proceeds of certain equity offerings. On and after July 1, 2016, the Co-Issuers may redeem all or part of the senior notes at a redemption price of 105.625% (with the redemption premium declining ratably each year to 100.000% on July 1, 2019), plus accrued and unpaid interest, if any.

The indenture restricts SMLP’s and the Co-Issuers’ ability and the ability of certain of their subsidiaries to: (i) incur additional debt or issue preferred stock; (ii) make distributions, repurchase equity or redeem subordinated debt; (iii) make payments on subordinated indebtedness; (iv) create liens or other encumbrances; (v) make investments, loans or other guarantees; (vi) sell or otherwise dispose of a portion of their assets; (vii) engage in transactions with affiliates; and (viii) make acquisitions or merge or consolidate with another entity. These covenants are subject to a number of important exceptions and qualifications. At any time when the senior notes are rated investment grade by each of Moody’s Investors Service, Inc. and Standard & Poor’s Ratings Services and no default or event of default under the indenture has occurred and is continuing, many of these covenants will terminate.

The indenture provides that each of the following is an event of default: (i) default for 30 days in the payment when due of interest on the senior notes; (ii) default in the payment when due of the principal of, or premium, if any, on the senior notes; (iii) failure by the Co-Issuers or SMLP to comply with certain covenants relating to merger, consolidation, sale of assets, change of control or asset sales; (iv) failure by SMLP for 180 days after notice to comply with certain covenants relating to the filing of reports with the SEC; (v) failure by the Co-Issuers or SMLP for 30 days after notice to comply with any of the other agreements in the indenture; (vi) specified defaults under any mortgage, indenture or instrument under which there may be issued or by which there may be secured or evidenced any indebtedness for money borrowed by SMLP or any of its restricted subsidiaries (or the payment of which is guaranteed by SMLP or any of its restricted subsidiaries); (vii) failure by SMLP or any of its restricted subsidiaries to pay certain final judgments aggregating in excess of $20.0 million; (viii) except as permitted by the indenture, any guarantee of the senior notes shall cease for any reason to be in full force and effect or any guarantor, or any person acting on behalf of any guarantor, shall deny or disaffirm its obligations under its guarantee of the senior notes; and (ix) certain events of bankruptcy, insolvency or reorganization described in the indenture. In the case of an event of default as described in the foregoing clause (ix), all outstanding senior notes will become due and payable immediately without further action or notice. If any other event of default occurs and is continuing, the trustee or the holders of at least 25% in principal amount of the then outstanding senior notes may declare all the senior notes to be due and payable immediately.

As of December 31, 2013, we were in compliance with the covenants for the senior notes. There were no defaults or events of default during the period from issuance through December 31, 2013.

6. PARTNERS' CAPITAL AND MEMBERSHIP INTERESTS

Partners' Capital

SMLP was formed in May 2012. Prior to the closing of its IPO on October 3, 2012, SMLP had no outstanding common or subordinated units or operations. A rollforward of the number of common limited partner, subordinated limited partner and general partner units follows.

	Common	Subordinated	General partner	Total
Units, January 1, 2012	—	—	—	—
Units issued to the public in connection with the IPO	14,380,000	—	—	14,380,000
Units issued to affiliates in connection with the IPO	10,029,850	24,409,850	996,320	35,436,020
Units issued	2,577	—	—	2,577
Units, December 31, 2012	24,412,427	24,409,850	996,320	49,818,597
Units issued to affiliates in connection with the Bison Drop Down	1,553,849	—	31,711	1,585,560
Units issued to affiliates in connection with the Mountaineer Acquisition	3,107,698	—	63,422	3,171,120
Units issued	5,892	—	—	5,892
Units, December 31, 2013	29,079,866	24,409,850	1,091,453	54,581,169

Bison Drop Down. On June 4, 2013, SMLP acquired Bison Midstream from SMP Holdings. SMP Holdings contributed 100% of the membership interests in Bison Midstream to SMLP, which concurrently contributed the membership interests to Summit Holdings. In exchange for its $305.4 million net investment in Bison Midstream, SMLP paid SMP Holdings and the general partner total cash and unit consideration of $248.9 million. As a result of the contribution of net assets in excess of consideration, SMLP recognized a capital contribution from SMP Holdings. The details of total cash and unit consideration as well as the calculation of the capital contribution and its allocation to partners' capital follow (dollars in thousands).

SMP Holdings' net investment in Bison Midstream		$ 305,449
Aggregate cash paid to SMP Holdings	$ 200,000	
Issuance of 1,553,849 SMLP common units to SMP Holdings	47,936	
Issuance of 31,711 SMLP general partner units to the general partner	978	
Total consideration		248,914
SMP Holdings' contribution of net assets in excess of consideration		$ 56,535
Allocation of capital contribution:		
General partner interest	$ 1,131	
Common limited partner interest	28,558	
Subordinated limited partner interest	26,846	
Partners' capital allocation		$ 56,535

The number of units issued to SMP Holdings and the general partner in connection with the Bison Drop Down was calculated based on an assumed equity issuance of $50.0 million and the five-day volume-weighted-average price as of June 3, 2013 of $31.53 per unit. The units were then valued as of June 4, 2013 (the date of closing) using the June 4, 2013 closing price of SMLP's units of $30.85.

The general partner interest allocation was calculated based on a 2% general partner interest in the contribution of assets in excess of consideration given by SMLP to SMP Holdings. Common and subordinated limited partner interests allocations were calculated as their respective percentages of total limited partner capital applied to the balance of the contribution by SMP Holdings after giving effect to the general partner allocation. See Notes 1, 5 and 13 for additional information.

Mountaineer Acquisition. On June 4, 2013, SMLP executed definitive agreements with MarkWest to acquire the Mountaineer Midstream system. On June 21, 2013, prior to closing the Mountaineer Acquisition and in accordance with the definitive agreements with MarkWest (the "MarkWest Agreement"), Mountaineer Midstream acquired all of the Mountaineer Gathering system assets. The total acquisition purchase price of $210.0 million was funded with $110.0 million of borrowings under SMLP’s revolving credit facility and the issuance of $100.0 million of SMLP common units and general partner interests to SMP Holdings and the general partner for cash. The allocation and valuation of units issued to SMP Holdings and the general partner to partially fund the Mountaineer Acquisition follow (dollars in thousands).

Issuance of 3,107,698 SMLP common units to SMP Holdings	$ 98,000
Issuance of 63,422 SMLP general partner units to the general partner	2,000
Issuance of units in connection with the Mountaineer Acquisition	$ 100,000

Pursuant to a unit purchase agreement, the number of units issued to SMP Holdings and the general partner in connection with the Mountaineer Acquisition was calculated based on an assumed equity issuance of $100.0 million and the five-day volume-weighted-average price as of June 3, 2013 of $31.53 per unit. See Notes 1, 5 and 13 for additional information.

Subordination. 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.

Cash Distribution Policy

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. 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%

Details of cash distributions declared follow.

Attributable to the quarter ended	Payment date	Per-unit distribution	Cash paid (or payable) to common unitholders	Cash paid (or payable) to subordinated unitholders	Cash paid (or payable) to general partner [(1)]	Total distribution
		(Dollars in thousands, except per-unit amounts)				
December 31, 2012	February 14, 2013	$ 0.4100	$ 10,009	$ 10,008	$ 408	$ 20,425
March 31, 2013	May 15, 2013	0.4200	10,253	10,252	418	20,923
June 30, 2013	August 14, 2013	0.4350	12,647	10,618	475	23,740
September 30, 2013	November 14, 2013	0.4600	13,377	11,229	502	25,108
December 31, 2013	February 14, 2014	0.4800	13,958	11,717	691	26,366

(1) Distributions attributable to the quarter ended December 31, 2013 include payments associated with the general partner's IDRs, which totaled $163,000. Our general partner was not entitled to receive incentive distributions for periods prior to the fourth quarter of 2013 based on the amount of the distributions declared per common and subordinated unit.

Membership Interests

Summit Investments' Equity in Contributed Subsidiaries. Summit Investments' equity in contributed subsidiaries represents its position in the net assets of Red Rock Gathering and Bison Midstream that have been acquired by SMLP. The balance also reflects net income attributable to Summit Investments for Red Rock Gathering and Bison Midstream for the periods beginning on their respective acquisition dates by Summit Investments and ending on the dates they were acquired by the Partnership. For the year ended December 31, 2013, net income was attributed to Summit Investments for (i) Red Rock Gathering for the full year and (ii) Bison Midstream for the period from February 16, 2013 to March 31, 2013. For the year ended December 31, 2012, net income was attributed to Summit Investments for Red Rock Gathering for the period from October 23, 2012 to December 31, 2012. Although included in partners' capital, these net income amounts have been excluded from the calculation of EPU for the years ended December 31, 2013 and 2012.

During the years ended December 31, 2013 and 2012, Summit Investments (i) incurred certain support expenses and capital expenditures on behalf of Red Rock Gathering and its subsidiary and (ii) allocated unit-based compensation expense and interest expense to Red Rock Gathering and its subsidiary. These transactions were settled through membership interests periodically. Also during the years ended December 31, 2013 and 2012, Red Rock Gathering received cash advances from and made cash advances to Summit Investments.

For additional information, see Notes 1, 2, 7 and 13.

Predecessor Membership Interests. Energy Capital Partners and GE Energy Financial Services hold membership interests in Summit Investments. Such membership interests give 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.

In April 2013, we repurchased the outstanding net profits interests in DFW Midstream. See Note 8 for additional information.

7. EARNINGS PER UNIT

The following table presents details on EPU.

	Year ended December 31,	
	2013	2012 (1)
	(Dollars in thousands, except per-unit amounts)	
Net income	$ 53,304	$ 42,997
Less: net income attributable to the pre-IPO period	—	24,112
Less: net income attributable to SMP Holdings	9,720	1,271
Net income attributable to SMLP	43,584	17,614
Less: net income attributable to general partner, including IDRs	1,035	352
Net income attributable to limited partners	$ 42,549	$ 17,262
Numerator for basic and diluted EPU:		
Allocation of net income among limited partner interests:		
Net income attributable to common units	$ 23,227	$ 8,632
Net income attributable to subordinated units	19,322	8,630
Net income attributable to limited partners	$ 42,549	$ 17,262
Denominator for basic and diluted EPU:		
Weighted-average common units outstanding – basic	26,951,346	24,412,427
Less: effect of non-vested phantom units and non-vested restricted units	150,133	131,558
Weighted-average common units outstanding – diluted	27,101,479	24,543,985
Weighted-average subordinated units outstanding – basic and diluted	24,409,850	24,409,850
Net income per limited partner unit:		
Common unit – basic	$ 0.86	$ 0.35
Common unit – diluted	$ 0.86	$ 0.35
Subordinated unit – basic and diluted	$ 0.79	$ 0.35

(1) Calculated for the period from October 1, 2012 to December 31, 2012

Our general partner was not entitled to receive incentive distributions for periods prior to the fourth quarter of 2013 based on the amount of the distributions declared per common and subordinated unit. There were no units excluded from diluted earnings per unit as we do not have any anti-dilutive units for the year ended December 31, 2013 or for the period from October 1, 2012 to December 31, 2012. See Notes 6 and 8 for additional information.

8. UNIT-BASED COMPENSATION

Long-Term Incentive Plan. The 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 5.0 million common units was reserved for issuance pursuant to and in accordance with the LTIP. As of December 31, 2013, approximately 4.7 million common units remained available for future issuance.

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 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.

The following table presents phantom and restricted unit activity:

	Units	Weighted-average grant date fair value
Nonvested phantom and restricted units, January 1, 2012	—	$ —
Phantom units granted	125,000	$ 20.00
Restricted units granted	6,558	$ 20.23
Nonvested phantom and restricted units, December 31, 2012	131,558	$ 20.00
Phantom units granted	155,330	$ 26.33
Restricted units granted	835	$ 27.50
Phantom units forfeited	(4,041)	$ 25.99
Nonvested phantom and restricted units, December 31, 2013	283,682	$ 23.41

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 IPO. All other phantom unit grants vest ratably over a three-year period. Grant date fair value is determined based on the closing price our our common units on the date of grant multiplied by the number of phantom units awarded to the grantee. Upon vesting, phantom unit awards may be settled in cash and/or common units, at the discretion of the board of directors. The restricted units granted in 2012 and 2013 maintained the vesting provisions of the share-based compensation awards they replaced, each of which had an original vesting period of four years. See "—DFW Net Profits Interests" for additional information.

Upon vesting, management intends to settle all phantom unit awards with common units. As of December 31, 2013, the unrecognized unit-based compensation related to the LTIP was $3.6 million. Incremental unit-based compensation will be recorded over the remaining vesting period of 2.67 years. Due to the limited and immaterial forfeiture history associated with the grants under the LTIP, no forfeitures were assumed in the determination of estimated compensation expense.

Unit-based compensation recognized in general and administrative expense related to awards under the LTIP was as follows:

	Year ended December 31, 2013		
	2013	2012	2011
	(In thousands)		
SMLP unit-based compensation	$ 2,999	$ 269	$ —

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"). Beginning in October 2012 and continuing into April 2013, we entered into a series of repurchases with the remaining seven holders of the then-outstanding DFW Net Profits Interests whereby we exchanged $12.2 million for their vested DFW Net Profits Interests and 7,393 SMLP restricted units for their unvested DFW Net Profits Interests. The repurchase prices were determined by valuing the vested and unvested net profits interests in relation to the enterprise value of DFW Midstream and represented fair value at the dates of repurchase. Upon the conclusion of these repurchase transactions, there were no remaining or outstanding DFW Net Profits Interests.

The DFW Net Profits Interests participated in distributions upon time vesting and the achievement of certain distribution targets to Class A members or higher priority vested DFW Net Profits Interests and were accounted for as compensatory awards. In addition to the net profits interests granted in 2009, additional DFW Net Profits Interests were granted on April 1, 2010 and July 28, 2010. Each grant vested ratably over four years and provided 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).

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 in 2011. As such, the 2009 and 2010 awards were valued retrospectively. The DFW Net Profits Interests were valued utilizing an option pricing method, which modeled the Class A and Class B membership interests as call options on the underlying equity value of DFW Midstream and considered 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 was 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 included 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 included 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 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, was 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,					
	2013		2012		2011	
	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	0.038%	$ 1,650	1.750%	$ 306	2.850%	$ 295
Repurchased	0.038%	$ 1,650	0.000%	$ —	0.000%	$ —
Granted	0.000%	$ —	0.000%	$ —	0.000%	$ —
Vested	0.000%	$ —	1.644%	$ 256	1.100%	$ 277
Forfeited	0.000%	$ —	0.069%	$ 765	0.400%	$ 220
Nonvested, end of period	0.000%	$ —	0.038%	$ 1,650	1.750%	$ 306
Vested, end of period	0.000%	$ —	4.294%	$ 257	2.650%	$ 258

We recognized 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,		
	2013	2012	2011
	(In thousands)		
Non-cash compensation expense	$ 17	$ 688	$ 2,171

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 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.

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. The SMP Net Profits Interests were retained by the Predecessor and as such are not reflected in SMLP's financial statements subsequent to the IPO, except as noted below.

During the year ended December 31, 2013, Summit Investments allocated $0.5 million of its annual expense associated with the SMP Net Profits Interests to Red Rock Gathering. This amount is reflected in general and administrative expenses in the statement of operations.

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%

Information regarding the amount and grant-date fair value of the vested and nonvested SMP Net Profits Interests for the periods in which they were reflected in our financial results was as follows:

	Year ended December 31,			
	2012		2011	
	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
Granted	0.500%	$ 1,780	2.000%	$ 1,505
Vested	1.271%	$ 965	0.986%	$ 818
Nonvested, end of period (1)	3.187%	$ 1,140	3.958%	$ 1,003
Vested, end of period	3.168%	$ 788	1.897%	$ 669

(1) Nonvested net profits interests subsequent to the IPO reflect obligations of the Predecessor and not the Partnership.

We recognized non-cash compensation expense ratably over the vesting period. Non-cash compensation expense, related to the SMP Net Profits Interests, recognized in general and administrative expense for the periods in which they were reflected in our financial results was as follows:

	Year ended December 31,		
	2013	2012	2011
		(In thousands)	
Non-cash compensation expense (1)	$ 490	$ 919	$ 1,269

(1) For the year ended December 31, 2013, reflects expenses allocated to Red Rock Gathering by Summit Investments prior to the Red Rock Drop Down

For the year ended December 31, 2011, non-cash compensation expense also included approximately $0.5 million of expense related to 2010 and 2009.

9. 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. 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 counterparties that are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated.

Counterparties accounting for more than 10% of total revenues were as follows:

	Year ended December 31,		
	2013	2012	2011
Revenue:			
Counterparty A	19%	27%	*
Counterparty B	15%	19%	34%
Counterparty C	*	14%	17%
Counterparty D	*	*	12%
Counterparty E	*	*	10%

** Less than 10%*

Counterparties accounting for more than 10% of total accounts receivable were as follows:

	December 31,	
	2013	2012
Accounts receivable:		
Counterparty A	37%	30%
Counterparty B	11%	18%
Counterparty C	—%	*
Counterparty D	*	*
Counterparty E	*	*

** Less than 10%*

10. RELATED-PARTY TRANSACTIONS

Recent Acquisitions and Partners' Capital Issuances. See Notes 5, 6 and 13 for disclosure of the purchase of Bison Midstream from SMP Holdings and the issuance of common units and general partner interests to SMP Holdings in connection with the Bison Drop Down and the Mountaineer Acquisition.

General and Administrative Expense Allocation. Our general partner and its affiliates do not receive a 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.

The payable to our general partner for expenses that were paid on our behalf and the receivable from the general partner for expenses that we paid that were not allocated to the Partnership were as follows:

	December 31,	
	2013	2012
	(In thousands)	
Due to affiliate	$ 653	$ —
Due from affiliate	—	774

Expenses incurred and allocated to us by the general partner under our partnership agreement were as follows:

	Year ended December 31,		
	2013	2012	2011
	(In thousands)		
General and administrative expense allocation	$ 3,914	$ 1,200	$ —

Additionally, during the year ended December 31, 2013, Summit Investments allocated $4.5 million of operation and maintenance expenses and $2.5 million of general and administrative expenses to Red Rock Gathering.

Electricity Management Services Agreement. We entered into a consulting arrangement with EquiPower Resources Corp. to assist with managing DFW Midstream's electricity price risk. EquiPower Resources Corp. is an affiliate of Energy Capital Partners and is also the employer of a director of our general partner. Amounts paid for such services were as follows:

	Year ended December 31,		
	2013	2012	2011
	(In thousands)		
Payments for electricity management consulting services	$ 199	$ 204	$ 11

Engineering Services Agreement. We entered into an engineering services arrangement with IPS Engineering/EPC. IPS Engineering/EPC is an affiliate of Energy Capital Partners. We paid $0.2 million for such services during the year ended December 31, 2013.

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.

11. BENEFIT PLAN

We established a defined contribution benefit plan for our employees in 2009. The expense associated with this plan was approximately $0.6 million in 2013, $0.2 million in 2012, and $0.1 million in 2011.

12. 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,		
	2013	2012	2011
	(In thousands)		
Total rent expense	$ 1,381	$ 732	$ 489

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, 2013 was as follows:

	Operating leases
	(In thousands)
2014	$ 1,365
2015	1,340
2016	1,288
2017	935
2018	690

Legal Proceedings. The Partnership is involved in various litigation and administrative proceedings arising in the normal course of business. In the opinion of management, any liabilities that may result from these claims would not individually or in the aggregate have a material adverse effect on its financial position or results of operations.

13. ACQUISITIONS

Red Rock Gathering System. On March 18, 2014, the Partnership acquired 100% of Red Rock Gathering from Summit Investments in exchange for total cash consideration of $206.7 million, subject to customary working capital adjustments. The acquisition of Red Rock Gathering was funded with the net proceeds from an offering of 5.3 million common units, $100.0 million of borrowings under our revolving credit facility and cash on hand. Because of the common control aspects in the drop down transaction, the Red Rock Drop Down was deemed a transaction between entities under common control and, as such, was accounted for on an “as if pooled” basis for all periods in which common control existed. SMLP’s financial results retrospectively include Red Rock Gathering’s financial results since October 23, 2012, the date Summit Investments acquired its interests in Red Rock Gathering, through December 31, 2013.

Summit Investments acquired the natural gas gathering pipeline, dehydration, compression and processing assets in the Piceance Basin in western Colorado and eastern Utah that comprise the Red Rock Gathering system from Energy Transfer Partners in September 2012 for $206.7 million (the "Red Rock Transaction"). Summit Investments' acquisition of the Red Rock Gathering system closed on October 23, 2012. Summit Investments accounted for its acquisition of Red Rock Gathering under the acquisition method of accounting. Red Rock Gathering's identifiable tangible and intangible assets acquired and liabilities assumed were recognized at their fair values as of October 23, 2012. The intangible assets that were acquired comprised right-of-way easements with a life of 20 years upon acquisition. Their fair values were determined based upon assumptions related to future cash flows, discount rates, asset lives, and projected capital expenditures to complete the Red Rock Gathering system. The final fair values of the assets acquired and liabilities assumed as of October 23, 2012, were as follows (in thousands):

Red Rock Gathering purchase price		$ 206,694
Cash	$ 1,097	
Accounts receivable	8,018	
Other assets	317	
Property, plant, and equipment	150,401	
Rights-of-way	52,197	
Other noncurrent assets	164	
Total assets acquired	212,194	
Trade accounts payable	2,558	
Other current liabilities	2,942	
Total liabilities assumed	$ 5,500	
Net identifiable assets acquired		$ 206,694

Bison Gas Gathering System. On February 15, 2013, Summit Investments acquired BTE and subsequently contributed it to SMP Holdings. On June 4, 2013, SMP Holdings entered into a purchase and sale agreement with SMLP whereby SMLP acquired the Bison Gas Gathering system. The Bison Gas Gathering system was carved out from BTE and primarily gathers natural gas production from Mountrail and Burke counties in North Dakota under long-term contracts ranging from five years to 15 years. The weighted-average life of the acquired contracts was 12 years upon acquisition.

For additional information, see Notes 1, 5 and 6.

Summit Investments accounted for its purchase of BTE (the "BTE Transaction") under the acquisition method of accounting, whereby the various gathering systems' identifiable tangible and intangible assets acquired and liabilities assumed were recorded based on their fair values as of February 15, 2013. 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 system.

Because the Bison Drop Down was executed between entities under common control, SMLP recognized the acquisition of the Bison Gas Gathering system at historical cost which reflected Summit Investments recent fair value accounting for the BTE Transaction. Furthermore, due to the common control aspect, the Bison Drop Down was accounted for by SMLP on an “as if pooled” basis for all periods in which common control existed. Common control began on February 15, 2013 concurrent with Summit Investments' acquisition of BTE.

The fair values of the assets acquired and liabilities assumed as of February 15, 2013, were as follows (in thousands):

Purchase price assigned to Bison Gas Gathering system		$ 303,168
Current assets	$ 5,705	
Property, plant, and equipment	85,477	
Intangible assets	164,502	
Other noncurrent assets	2,187	
Total assets acquired	257,871	
Current liabilities	6,112	
Other noncurrent liabilities	2,790	
Total liabilities assumed	$ 8,902	
Net identifiable assets acquired		248,969
Goodwill		$ 54,199

We believe that the goodwill recorded represents the incremental value of future cash flow potential attributed to estimated future gathering services within the Williston Basin.

The Bison Drop Down closed on June 4, 2013. The total acquisition purchase price of $248.9 million was funded with $200.0 million of borrowings under SMLP's revolving credit facility and the issuance of $47.9 million of SMLP common units to SMP Holdings and $1.0 million of general partner interests to SMLP's general partner. SMP Holdings had a net investment in the Bison Gas Gathering system of $303.2 million and received total consideration of $248.9 million from SMLP. As a result, SMLP recognized a capital contribution from SMP Holdings for the contribution of net assets in excess of consideration paid. See Notes 1, 5 and 6 for additional information.

Mountaineer Midstream. We completed the acquisition of Mountaineer Midstream from MarkWest for $210.0 million on June 21, 2013. The Mountaineer Midstream natural gas gathering and compression assets are located in the Appalachian Basin which includes the Marcellus Shale formation primarily in Doddridge County in northern West Virginia. The Mountaineer Midstream system consists of newly constructed, high-pressure gas gathering pipelines, certain rights-of-way associated with the pipeline, and two compressor stations. The assets gather natural gas under a long-term, fee-based contract with an affiliate of Antero Resources Corp. The life of the acquired contract was 13 years upon acquisition.

The Mountaineer Acquisition was funded with $110.0 million of borrowings under the Partnership's revolving credit agreement and the issuance of $100.0 million of common and general partner interests to SMP Holdings. For the year ended December 31, 2013, SMLP recorded $9.6 million of revenue and $2.3 million of net income related to Mountaineer Midstream.

SMLP accounted for the Mountaineer Acquisition under the acquisition method of accounting. As of June 30, 2013, we preliminarily assigned the full $210.0 million purchase price to property plant and equipment. During the third quarter of 2013, we received additional information and, as a result, preliminarily assigned $158.3 million of the purchase price to property, plant and equipment, $27.1 million to contract intangibles, $6.5 million to rights-of-way and $18.1 million to goodwill. During the fourth quarter of 2013, we received additional information from MarkWest and finalized the purchase price allocation.

The final fair values of the assets acquired and liabilities assumed as of June 21, 2013, were as follows (in thousands):

Purchase price assigned to Mountaineer Midstream		$ 210,000
Property, plant, and equipment	$ 163,661	
Gas gathering agreement contract intangibles	24,019	
Rights-of-way	6,109	
Total assets acquired	193,789	
Total liabilities assumed	$ —	
Net identifiable assets acquired		193,789
Goodwill		$ 16,211

See Notes 1, 5 and 6 for additional information.

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. We 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

Pooling of Interests. As noted above, the Bison Drop Down and the Red Rock Drop Down were transactions between commonly controlled entities which required that we account for the acquisitions in a manner similar to a pooling of interests. As a result, the historical financial statements of the Partnership, the Bison Gas Gathering system and Red Rock Gathering have been combined to reflect the historical operations, financial position and cash flows from the dates that common control began. See Note 1 for additional information. Revenues and net income for the previously separate entities and the combined amounts for the years ended December 31, 2013 and 2012, as presented in these consolidated financial statements follow.

	Year ended December 31,	
	2013	**2012**
	(In thousands)	
SMLP revenues	$ 225,192	$ 165,499
Red Rock Gathering revenues	50,114	8,924
Bison Gas Gathering system revenues	17,614	—
Combined revenues	$ 292,920	$ 174,423
SMLP net income	$ 43,584	$ 41,726
Red Rock Gathering net income	9,668	1,271
Bison Gas Gathering system net income	52	—
Combined net income	$ 53,304	$ 42,997

Unaudited Pro Forma Financial Information. The following unaudited pro forma financial information assumes that:

- The acquisition of Bison Midstream occurred on January 1, 2012. The pro forma results for Bison Midstream were derived from revenues and net income in 2013 and 2012.
- The acquisition of Mountaineer Midstream occurred on January 1, 2012. The pro forma results for Mountaineer Midstream were derived from revenues and net income in 2013. Mountaineer Midstream was not operational until November 2012.
- The acquisition of Red Rock Gathering occurred on January 1, 2011. The pro forma results for Red Rock Gathering were derived from actual revenues and net income in 2013 and by annualizing the actual operating results for Red Rock Gathering that were recorded in 2012 for the years ended December 31, 2012 and 2011.
- The acquisition of Grand River Gathering occurred on January 1, 2010. The pro forma results for Grand River Gathering were derived by annualizing the actual operating results for Grand River Gathering that were recorded in 2011.
- Pro forma net income for the year ended December 31, 2013 has been adjusted to remove the impact of $2.5 million of nonrecurring transaction costs associated with the acquisitions of Bison Midstream and Mountaineer Midstream.
- Pro forma net income for the year ended December 31, 2012 has been adjusted to remove the impact of $1.6 million of nonrecurring transaction costs associated with the acquisition of Red Rock Gathering.
- Pro forma net income for the year ended December 31, 2011 has been adjusted to remove the impact of $3.2 million of nonrecurring transaction costs associated with the acquisition of Grand River Gathering.
- Pro forma adjustments in 2013 and 2012 also reflect the impact of $310.0 million of incremental borrowings on our revolving credit facility for the Bison Midstream and Mountaineer Midstream acquisitions and incremental depreciation and amortization expense associated with the acquired property, plant and equipment and contract intangibles as a result of the application of fair value accounting for Bison Midstream.
- Pro forma adjustments in 2013, 2012 and 2011 also reflect the combined impact of a 5,300,000 common unit issuance and $100.0 million of incremental borrowings on our revolving credit facility to fund the acquisition of Red Rock Gathering.

	Year ended December 31,		
	2013	2012	2011
	(In thousands)		
Total Bison Midstream and Mountaineer Midstream revenues included in consolidated revenues	$ 60,323	$ —	$ —
Total Red Rock Gathering revenues included in consolidated revenues	50,114	8,924	—
Total Grand River Gathering revenues included in consolidated revenues			12,824
Total Bison Midstream and Mountaineer Midstream net income included in consolidated net income	$ (457)	$ —	$ —
Total Red Rock Gathering net income included in consolidated net income	9,668	1,271	—
Total Grand River Gathering net income included in consolidated net income			2,660
Pro forma total revenues	$ 305,071	$ 256,637	$ 221,215
Pro forma net income	47,371	38,639	58,461
Pro forma common EPU - basic and diluted	$ 0.79	$ 0.28	
Pro forma subordinated EPU - basic and diluted	0.79	0.28	

The unaudited pro forma financial information presented above is not necessarily indicative of (i) what our financial position or results of operations would have been if the acquisitions of Bison Midstream and Mountaineer Midstream had occurred on January 1, 2012, if the acquisition of Red Rock Gathering had occurred on January 1, 2011 or if the Grand River Transaction had occurred on January 1, 2010, or (ii) what SMLP's financial position or results of operations will be for any future periods.

14. SUBSEQUENT EVENT

On March 8, 2014, Summit Investments offered its interests in Red Rock Gathering to the Partnership. The Red Rock Drop Down closed on March 18, 2014. For additional information, see Notes 1 and 13.

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, General Counsel and Chief Compliance Officer.

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 2013, 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, 2013, 2012 and 2011. For 2013, the amounts shown in the summary compensation table below have been allocated to SMLP by the general partner as noted above. 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 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	2013	$ 280,000	$ —	$ 332,500	$ 900,000	$ 12,845	$ 1,525,345
President and Chief Executive Officer	2012	354,673	—	393,738	350,000	7,500	1,105,911
	2011	295,500	250,000	—	—	8,865	554,365
Matthew S. Harrison	2013	$ 261,907	$ —	$ 225,250	$ 400,000	$ 42,251	$ 929,408
Senior Vice President and Chief Financial Officer (6)	2012	278,872	—	236,332	295,000	27,116	837,320
	2011	87,176	240,000	—	911,000	—	1,238,176
Brock M. Degeyter	2013	$ 225,250	$ 63,750	$ 208,250	$ 375,000	$ 13,388	$ 885,638
Senior Vice President, General Counsel and Chief Compliance Officer(7)	2012	221,983	75,000	231,635	1,140,000	5,097	1,673,715
	2011	—	—	—	—	—	—

(1) The amounts shown for 2013 represent that portion of the named executive officers' base salary allocated to SMLP. 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 2013 and 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 Summit Investments.

(3) Represents incentive bonus earned under our annual incentive bonus program for the year ended December 31, 2013 and paid in March 2014, and 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

2013 and 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 Administrative Expenses Allocation" in Item 13. Certain Relationships and Related Transactions, and Director Independence. Prior to 2012, our named executive officers received discretionary bonuses.

(4) Amounts shown in this column for 2013 for Messrs. Newby, Harrison and Degeyter reflect the grant date fair value of the phantom unit awards granted to the named executive officers in March 2013, in accordance with Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") Topic 718, *Compensation—Stock Compensation* ("FASB ASC Topic 718"). 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 amounts shown in this column for 2012 for Mr. Degeyter and for 2011 for Mr. Harrison reflect the grant date fair value of their pre-IPO equity awards in accordance with FASB ASC Topic 718. See Note 8 to the audited consolidated financial statements for the assumptions made in valuing these awards.

(5) Amounts shown in this column for Mr. Newby include (i) employer contributions under the 401(k) Plan of $8,925 in 2013, $7,500 in 2012 and $8,865 in 2011, (ii) $2,100 relating to individual tax preparation and advisory fees paid by the Partnership in 2013 and (iii) $1,820 for Mr. Newby's annual medical examination in 2013. Amounts shown in this column for Mr. Harrison include (i) employer contributions under the 401(k) Plan of $10,838 in 2013 and $7,500 in 2012, (ii) $2,550 relating to individual tax preparation and advisory fees paid by the Partnership in 2013, and (iii) pursuant to the terms of his employment agreement, payments for relocation expense reimbursement of $28,864 in 2013 and $19,616 in 2012. Amounts shown in this column for Mr. Degeyter include (i) employer contributions under the 401(k) Plan of $10,838 in 2013 and $5,097 in 2012 and (ii) $2,550 relating to individual tax preparation and advisory fees paid by the Partnership in 2013. As noted above, amounts for periods or events post-IPO have been allocated in accordance with the cost allocation methodology discussed in Item 13. Certain Relationships and Related Transactions, and Director Independence.

(6) Mr. Harrison commenced employment with our general partner 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 our general partner 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. Mr. Harrison and Mr. Degeyter each received base salary adjustments in 2013, Mr. Degeyter's salary was further adjusted in connection with the renewal of his employment agreement in 2014, and Mr. Newby's salary received a base salary adjustment in 2014. 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	$	475,000	(1)
Matthew S. Harrison Senior Vice President and Chief Financial Officer		340,000	(2)
Brock M. Degeyter Senior Vice President, General Counsel and Chief Compliance Officer		305,000	(3)

(1) In March of 2014, Mr. Newby's base salary was adjusted upward from $400,000 to $475,000 to bring his salary in line with the current market.

(2) In September of 2013, Mr. Harrison's base salary was adjusted upward from $295,000 to $340,000 to bring his salary in line with the current market.

(3) In January of 2014, Mr. Degeyter's base salary was adjusted upward from $265,000 to $305,000 to bring his salary in line with the current market.

Annual Incentive Compensation. For 2013, Messrs. Newby, Harrison and Degeyter had target bonuses of $400,000, $255,000, $198,750 respectively, or 100%, 75% and 75% of their base salaries, respectively. Quantitative factors, as reflected in the corporate scorecard applicable to the senior leadership team (the "SLT Scorecard") determined one-half of the incentive compensation for Messrs. Harrison and Degeyter, while their respective business unit scorecards accounted for the remaining half. For Mr. Newby, the SLT Scorecard determined his entire annual incentive bonus for 2013.

The SLT Scorecard contained four objective factors related to the corporate enterprise's key objectives for 2013, including Adjusted EBITDA thresholds, safety goals, adjusted distributable cash flow thresholds, and corporate growth goals. Although we did not meet our safety goals 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 102% of target for the portion of their bonuses based on the SLT Scorecard.

Mr. Newby's annual bonus payout was adjusted upward to $475,000, which is approximately 119% of his target bonus for 2013, primarily due to his leadership in achieving strong operational results for our business, including operational and cost performance, and his significant contributions to the strategic transactions of the Partnership and its affiliates.

Mr. Harrison was awarded 105% of target for the portion of his bonus based on the performance of the enterprise technology, finance and accounting business units. In total, Mr. Harrison's annual bonus payout was adjusted upward to $265,000, which is approximately 115% of his target bonus for 2013, primarily due to his significant contributions to the finance and capital markets transactions of the Partnership and its affiliates and various other enterprise technology, finance and accounting initiatives.

Mr. Degeyter was awarded 105% 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 $245,000, which is approximately 123% of his target bonus for 2013, primarily due to his significant contributions to the acquisitions, finance and capital markets transactions of the Partnership and its affiliates, and various other 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 "General and Administrative Expenses Allocation" in Item 13. Certain Relationships and Related Transactions, and Director Independence.

Long-Term Equity-Based Compensation Awards. In March 2013, the Board granted 34,629, 15,391 and 14,429 phantom units to Messrs. Newby, Harrison and Degeyter, respectively, pursuant to our long-term equity incentive plan, which is discussed in more detail under "2012 Long-Term Incentive Plan" below. The phantom units granted to the named executive officers in March 2013 vest ratably over a three-year period, 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 2013, we made a fully vested matching contribution on behalf of each of the 401(k) plan's participants up to 5% of such participant's eligible salary for the year. In 2013, pursuant to the terms of his employment agreement, Mr. Harrison was reimbursed for certain relocation expenses. Also, pursuant to the terms of their employment agreements, the named executive officers are entitled to certain additional benefits on a limited basis. Those additional benefits include individual tax preparation and advisory services, and annual preventive health maintenance. Expenditures for these additional benefits are disclosed by individual in footnote 5 to the Summary Compensation Table.

Outstanding Equity Awards at December 31, 2013

The following table provides information regarding the phantom unit awards held by the named executive officers as of December 31, 2013.

Name	Number of phantom units that have not vested (1)	Market value of phantom units that have not vested (2)
Steven J. Newby	52,129	$ 1,910,528
Matthew S. Harrison	30,141	1,104,668
Brock M. Degeyter	26,929	986,948

(1) All phantom units granted to the named executive officers in March 2013 vest ratably over a three-year period, with the first tranche scheduled to vest on March 15, 2014. 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. Both the 2013 grants and the IPO grants are subject to accelerated vesting on the occurrence of any of the following events: (i) a termination of the named executive officer's

employment other than for cause, (ii) a termination of the named executive officer's employment by the named executive officer for good reason (as defined in the named executive officer's employment agreement), (iii) a termination of the named executive officer's employment by reason of the named executive 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, 2013.

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 100% of his base salary. Mr. Newby is entitled to receive a prorated annual bonus (based on target) if his employment is terminated by Summit Investments without cause or due to death or disability. In addition, Mr. Newby's employment agreement provides that Summit Investments will reimburse him for tax preparation services and ongoing tax advice up to $10,000 per year, as well as an annual medical examination.

Mr. Newby's employment agreement provides for a cash severance payment upon a termination by Summit Investments without cause or by Mr. Newby for good reason, which is defined generally as the named executive 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 named executive officer's base compensation, (iii) a material change in the geographic location at which the named executive 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 Summit Investments (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 Summit Investments 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 his annual bonus payable in respect of the immediately preceding year.

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, Summit Investments may choose to subject him to a non-competition covenant for up to one year post-termination. If Summit Investments exercises this "non-compete option", then Mr. Newby would be entitled to a severance payment in an amount equal to the sum of his annual base salary and his annual bonus payable in respect of the immediately 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 Summit Investments) 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 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, which was amended and restated as of September 13, 2013, 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 $340,000, and a performance-based bonus ranging from 0% to 150% of base salary, with a target of 75% of base salary. Mr. Harrison is entitled to receive a prorated annual bonus (based on target) if his employment is terminated by Summit Investments without cause or due to death or disability. In addition, Mr. Harrison's employment agreement also provides for reimbursement of certain expenses incurred in connection with his relocation to Atlanta, Georgia, and reimbursement for tax preparation expenses in the amount of $10,000 per year.

Mr. Harrison's employment agreement provides for a cash severance payment upon a termination by Summit Investments without cause or by Mr. Harrison for good reason, which is defined generally as the named executive 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 named executive officer's base compensation, (iii) a material change in the geographic location at which the named executive 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 Summit Investments (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 Summit Investments and ending on the 12-month anniversary of such a change in control, Mr. Harrison'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. Harrison's severance payment will increase to one and one-half times the sum of his annual base salary and his annual bonus payable in respect of the immediately preceding year.

Following any termination of employment other than one resulting from non-extension of the term, his 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. If Mr. Harrison's employment is terminated due to non-extension of the term, Summit Investments may choose to subject him to a non-competition covenant for up to one year post-termination. If Summit Investments exercises this "non-compete option", then Mr. Harrison would be entitled to a severance payment in an amount equal to the sum of his annual base salary and his annual bonus payable in respect of the immediately 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 Summit Investments) and the denominator of which is 365. In this case, the severance payment will be payable in equal installments over the restricted period. Following any termination of employment, Summit Investments has agreed to pay the out-of-pocket premium cost to continue Mr. Harrison's medical and dental coverage for a period not to exceed 18 months, with such coverage terminating if any new employer provides benefits coverage.

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

Mr. Harrison's employment agreement provides that, if any portion of the payments or benefits provided to Mr. Harrison 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. Harrison.

Mr. Degeyter's employment agreement, which was amended and restated as of January 18, 2014, is substantially identical to Mr. Harrison's employment agreement, except that it provides for an annual base salary of $305,000.

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, at December 31, 2013, an aggregate of 283,682 common units could be delivered pursuant to awards under the LTIP. Units that are canceled or forfeited will be available for delivery pursuant to future 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 February 2014, in an effort to bring the Partnership's equity awards in line with its peer group and make the award amounts internally consistent across its employee population, our Compensation Committee adopted LTIP award guidelines. Generally, the LTIP award guidelines provide that a certain group of high-performing employees will be eligible to receive long-term equity awards each year in an amount equal to a specified percentage of the employee's base salary; however, the Compensation Committee may, in its discretion, grant a greater or lesser amount of equity awards if deemed appropriate. These guidelines will be applicable to our executive officers starting in 2014, and provide for a targeted annual equity award in the amount of 125% of base salary for each of our executive officers other than Mr. Newby, whose targeted annual equity award will be 225% of his base salary.

On March 6, 2014, based on the recommendation of the Compensation Committee, the board of directors approved a grant of phantom units valued at $1,200,000 to Mr. Newby, a grant of phantom units valued at $625,000 to Mr. Harrison, and a grant of phantom units valued at $600,000 to Mr. Degeyter. The underlying phantom units, which will be granted to the named executive officers on March 15, 2014, vest ratably over a three-year period. 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. All LTIP grants to our named executive officers are subject to accelerated vesting on the occurrence of any of the following events: (i) a termination of the named executive officer's employment other than for cause, (ii) a termination of the named executive officer's employment by the officer for good reason (as defined in the named executive officer's employment agreement), (iii) a termination of the named executive officer's employment by reason of the named executive officer's death or disability or (iv) a Change in Control (as defined in the applicable award agreement).

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 in 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.

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

Since its creation in August 2013, the Compensation Committee provides oversight, administers and makes decisions regarding our compensation policies and plans. Additionally, the Compensation Committee 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 Compensation Committee has recommended to the board of directors of our general partner that the Compensation Discussion and Analysis be included in this report for filing with the SEC.

Members of the Compensation Committee of Summit Midstream GP, LLC		
Thomas K. Lane	Jeffrey R. Spinner	Robert M. Wohleber

Director Compensation

Mr. Morgan and the independent directors, which currently include Mr. Peters, Ms. Tomasky and Mr. Wohleber, each received a $50,000 annual retainer and $50,000 in annual unit-based compensation in 2013. These amounts were paid in conjunction with the individual's appointment to the board of directors or the anniversary thereof. In addition, for 2013, 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
- in connection with the Bison Midstream drop down transaction, in April 2013, we paid the members of the Conflicts Committee fees of $10,000 each for the increased time and effort that they expended in connection with their service on the Conflicts Committee, which reviewed the transaction for fairness to the Partnership and its unitholders.

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. We do not compensate employees of Summit Investments or Energy Capital Partners for their services as directors.

We reimburse all directors, except for employees of Energy Capital Partners for travel and other related expenses in connection with attending board and committee meetings and board-related activities.

The following table shows the director compensation in 2013.

Name	Fees earned or paid in cash	Other fees	Unit awards (1)	Total
Thomas K. Lane	$ —	$ —	$ —	$ —
Christopher M. Leininger	—	—	—	—
Curtis A. Morgan	50,000	—	50,000	100,000
Steven J. Newby	—	—	—	—
Jerry L. Peters	50,000	26,500	50,000	126,500
Jeffrey R. Spinner	—	—	—	—
Susan Tomasky	50,000	19,000	50,000	119,000
Robert M. Wohleber	50,000	4,500	50,000	104,500

(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.

In November 2013, in an effort to bring the Partnership's director compensation in line with its peer group, our Compensation Committee recommended, and the board of directors approved certain changes to our director compensation program. Specifically, the annual cash retainer was increased from $50,000 to $60,000, and the annual unit retainer was increased from common units valued at $50,000 to common units valued at $70,000. In addition, the committee member retainer was increased from $1,500 to $5,000 per member for each committee.

In 2013, Messrs. Morgan and Peters elected to defer receipt of their annual cash retainers pursuant to the terms of the Summit Midstream Partners, LLC Deferred Compensation Plan (the “Deferred Compensation Plan”). The Deferred Compensation Plan is filed as Exhibit 10.1 to the Partnership’s Current Report on Form 8-K filed on July 3, 2013.

Compensation Committee Interlocks and Insider Participation

In August 2013, the board of directors of our general partner formally appointed a Compensation Committee, consisting of Mr. Lane, Mr. Spinner and Mr. Wohleber. Although our common units are listed on the New York Stock Exchange, we have taken advantage of the “Limited Partnership” exemption to the New York Stock Exchange rule requiring listed companies to have an independent compensation committee with a written charter. During 2013, no member of the Compensation Committee was an executive officer of another entity on whose compensation committee or board of directors any executive officer of Summit Investments (and in connection therewith, SMLP) served. During 2013, no director was an executive officer of another entity on whose compensation committee any executive officer of Summit Investments (and in connection therewith, SMLP) served.

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 of directors concerning named executive officer compensation, and makes recommendations to the Compensation Committee regarding named executive officer compensation but abstains from any decisions regarding his compensation. Also, Mr. Lane and Mr. Spinner were selected to serve on the Compensation Committee due to their affiliations with Energy Capital Partners, which controls our general partner.