Summit Midstream Partners, LP
Form 10-K
February 29, 2016

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K
(Mark One)
[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2015
or
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission file number: 001-35666
Summit Midstream Partners, LP
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	45-5200503 (I.R.S. Employer Identification No.)
1790 Hughes Landing Blvd, Suite 500 The Woodlands, TX (Address of principal executive offices)	77380 (Zip Code)

Registrant’s telephone number, including area code: (832) 413-4770

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

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

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

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

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

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

The aggregate market value of the common units held by non-affiliates of the registrant as of June 30, 2015, was $1,208,505,269.

Indicate the number of shares outstanding of each of the issuer’s classes of common stock, as of the latest practicable date: The registrant had 66,472,494 common units and 1,354,700 general partner units outstanding at February 16, 2016.

DOCUMENTS INCORPORATED BY REFERENCE

None

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Glossary of Terms
adjusted EBITDA: EBITDA plus adjustments related to MVC shortfall payments, impairments and other noncash expenses or losses, less other noncash income or gains
AMI: area of mutual interest; AMIs require that any production from wells drilled by our customers within the AMI be shipped on and/or processed by our gathering systems
associated natural gas: a form of natural gas which is found with deposits of petroleum, either dissolved in the oil or as a free gas cap above the oil in the reservoir
Bbl: one barrel; used for crude oil and produced water and equivalent to 42 U.S. gallons
Bcf: one billion cubic feet
condensate: a natural gas liquid with a low vapor pressure, mainly composed of propane, butane, pentane and heavier hydrocarbon fractions
conventional resource basin: a basin where natural gas or crude oil production is developed from a well drilled into a geologic formation in which the reservoir and fluid characteristics permit the crude oil and natural gas to readily flow to the wellbore; also referred to as a conventional resource play
delivery point: the point where hydrocarbons or produced water are delivered into a gathering system, processing or fractionation facility or downstream transportation pipeline
distributable cash flow: adjusted EBITDA plus cash interest received, less cash interest paid, senior notes interest adjustment, cash taxes paid and maintenance capital expenditures
dry gas: a gas primarily composed of methane where heavy hydrocarbons and water either do not exist or have been removed through processing or treating
EBITDA: net income or loss, plus interest expense, income tax expense, and depreciation and amortization, less interest income and income tax benefit
end users: the ultimate users and consumers of transported energy products
hub: geographic location of a storage facility and multiple pipeline interconnections
LACT unit: lease automatic custody transfer unit; a system for ownership transfer of hydrocarbons or produced water from the production site to trucks, pipelines or storage tanks
Mbbl: one thousand barrels
Mbbl/d: one thousand barrels per day
Mcf: one thousand cubic feet
Mcfe: the equivalent of one thousand cubic feet; generally calculated when liquids are converted into gas; determined using a ratio of six thousand cubic feet of natural gas to one barrel of crude oil
MMBtu: one million British Thermal Units
MMcf: one million cubic feet
MMcf/d: one million cubic feet per day
MQD: minimum quarterly distribution; SMLP's partnership agreement has established a minimum quarterly distribution of $0.40 per unit per quarter, or $1.60 per unit per year

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MVC: minimum volume commitment; an MVC contractually obligates a customer to ship natural gas, crude oil or produced water on SMLP's systems and/or use our processing services for a minimum quantity of natural gas
NGLs: natural gas liquids; the combination of ethane, propane, normal butane, iso-butane and natural gasolines that when removed from unprocessed natural gas streams become liquid under various levels of higher pressure and lower temperature
play: a proven geological formation that contains commercial amounts of hydrocarbons
produced water: water from underground geologic formations that is brought to the surface during crude oil production
receipt point: the point where hydrocarbons or produced water are received by or into a gathering system or transportation pipeline
residue gas: the natural gas remaining after being processed and/or treated
segment adjusted EBITDA: calculated as adjusted EBITDA excluding the impact of the corporate expenses that we allocate to our reportable segments
shortfall payment: the payment received from a counterparty when its volume throughput does not meet its MVC for the applicable period
tailgate: refers to the point at which processed residue gas and NGLs leave a processing facility for end-use markets
Tcf: one trillion cubic feet
throughput volume: the volume of natural gas, crude oil or produced water transported or passing through a pipeline, plant or other facility during a particular period; also referred to as volume throughput
unconventional resource basin: a basin where natural gas or crude oil production is developed from unconventional sources that require hydraulic fracturing as part of the completion process, for instance, natural gas produced from shale formations and coalbeds; also referred to as an unconventional resource play
wellhead: the equipment at the surface of a well used to control the well's pressure; also, the point at which the hydrocarbons and water exit the ground

Industry Overview

General

The midstream sector of the energy industry provides the link between exploration and production and the delivery of crude oil, natural gas and their components to end-use markets. The midstream sector consists generally of gathering, processing, storage, and transportation activities. We provide natural gas gathering, treating and processing services as well as crude oil and produced water gathering services.

Natural Gas Midstream Services

Companies within the natural gas midstream 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 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 range of services provided by midstream natural gas service companies 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. Gathering systems are typically designed to allow gathering of natural gas at different pressures and are scalable to allow for additional production and well connections.

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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 treating, dehydration, processing and fractionation facilities and ultimately 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. 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. 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, which is often 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 and fractionation facility 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 either stored or 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.

Crude Oil Midstream Services

Crude Oil Gathering. Pipelines typically provide the most cost-effective option for shipping crude oil. Crude oil gathering systems typically comprise a network of small-diameter pipelines connected directly to well heads, pad sites or other receipt points that transport crude oil to central receipt points or interconnecting pipelines through larger diameter trunk lines. Common carrier pipelines frequently transport crude oil from central delivery points to logistics hubs or refineries under tariffs regulated by the Federal Energy Regulatory Commission, also known as FERC, or state authorities. Logistic hubs provide storage and connections to other pipeline systems and modes of transportation, such as railroads and trucks. Pipelines not engaged in the interstate transportation of crude may also be proprietary or leased entirely to a single customer.

Trucking complements pipeline gathering systems by gathering crude oil from operators at remote wellhead locations not served by pipeline gathering systems. Trucking is generally limited to low volume, short haul movements because trucking costs escalate with distance. Railroads provide additional transportation capabilities for shipping crude oil between gathering systems, pipelines, terminals and storage centers and end-users.

Produced Water Gathering. Produced water is a by-product or waste stream associated with crude oil production. The cost of managing produced water is a key consideration for crude oil producers. Pipelines and trucking are used to gather produced water for transport to disposal facilities. Similar to crude oil gathering, trucking is generally limited to low volume, short haul movements.

Contractual Arrangements

Natural Gas Contracts. Natural gas midstream 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 natural gas gathering contracts are described below.

Fee-Based. Under fee-based arrangements, the midstream service provider typically receives a fee for each unit of natural gas gathered, treated and/or compressed at the wellhead and an additional fee per unit of natural gas processed

at its facility. As a result, the midstream service provider bears no direct commodity price risk exposure.
Percent-of-Proceeds. Under percent-of-proceeds arrangements, the midstream service provider typically remits to the producers either a percentage of the proceeds from the sale of residue gas and NGLs at the tailgate at its own

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or a third-party processing or fractionation plant. 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, condensate and NGLs.

Keep-Whole. Under keep-whole arrangements, the midstream 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 midstream service provider compensates the producer for the value or amount of natural gas used and removed during 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.

Crude Oil and Produced Water Contracts. Crude oil and produced water gathering services are usually provided under fee-based contractual arrangements whereby the service provider typically receives a fee for each unit of production gathered at the wellhead. As a result, the service provider bears no direct commodity price risk exposure.

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PART I

Item 1. Business.

Summit Midstream Partners, LP ("SMLP" or the "Partnership") is a Delaware limited partnership that completed its initial public offering ("IPO") on October 3, 2012. Summit Midstream Partners, LLC ("Summit Investments") is a Delaware limited liability company and the predecessor for accounting purposes (the "Predecessor") of SMLP. References to the "Company," "we," or "our," when used for dates or periods ended on or after the IPO, refer collectively to SMLP and its subsidiaries. References to the "Company," "we," or "our," when used for dates or periods ended prior to the IPO, refer collectively to Summit Investments and its subsidiaries. For additional information, see Note 1 to the consolidated financial statements.

Item 1. Business is divided into the following sections:

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 the continental United States. We provide natural gas gathering, treating and processing services as well as crude oil and produced water gathering services pursuant to primarily long-term and fee-based agreements with our customers and counterparties. We generally refer to all of the services provided as 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.

We contract with producers to gather natural gas from pad sites, wells and central receipt points connected to our systems. We then compress, dehydrate, treat and/or process these volumes for delivery to downstream pipelines for ultimate delivery to third-party processing plants and/or end users. We also contract with producers to gather crude oil and produced water from wells connected to our systems for delivery to third-party rail terminals and pipelines in the case of crude oil and to third-party disposal wells in the case of produced water.

Our systems, each of which are located in the continental United States, and the basins they serve are as follows:

- the Mountaineer Midstream system, a natural gas gathering system ("Mountaineer Midstream"), which serves the Appalachian Basin;
- the Bison Midstream system, an associated natural gas gathering system ("Bison Midstream"), which serves the Williston Basin;
- the Polar and Divide system, a crude oil and produced water gathering system and recently commissioned transmission pipelines ("Polar and Divide"), which serves the Williston Basin;
- the DFW Midstream system, a natural gas gathering system ("DFW Midstream"), which serves the Fort Worth Basin; and

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- the Grand River system, a natural gas gathering and processing system ("Grand River"), which serves the Piceance Basin.

We believe that our gathering systems are well positioned to capture volumes from producer activity in these regions in the future.

We have a diverse group of customers and counterparties comprising affiliates and/or subsidiaries of some of the largest crude oil and natural gas producers in North America. Our anchor customers and the systems they serve are as follows:

- Antero Resources Corp. ("Antero"), the anchor for Mountaineer Midstream;
- EOG Resources, Inc. ("EOG") and Oasis Petroleum, Inc. ("Oasis"), the anchors for Bison Midstream;
- Whiting Petroleum Corp. ("Whiting") and SM Energy Company ("SM Energy"), the anchors for Polar and Divide;
- Chesapeake Energy Corporation ("Chesapeake"), the anchor for DFW Midstream; and
- Encana Corporation ("Encana") and WPX Energy, Inc. ("WPX"), the anchors for Grand River.

A significant percentage of our revenue is attributable to these anchor customers. For additional information on revenue and accounts receivable concentrations, see the Liquidity and Capital Resources—Credit and Counterparty Concentration Risks section included in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A") and Notes 3 and 9 to the consolidated financial statements.

We believe that we have positioned SMLP for growth through the increased utilization and further development of our existing midstream assets. We 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 and we have no obligation to acquire any assets that they offer to us. We also 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 exploration and production projects.

Organization

We conduct our gathering, treating and processing operations in the midstream sector through five gathering systems. As of December 31, 2015, our reportable segments and their respective gathering systems were:

- the Marcellus Shale, which is served by Mountaineer Midstream;
- the Williston Basin, which is served by Bison Midstream and Polar and Divide;
- the Barnett Shale, which is served by DFW Midstream; and
- the Piceance Basin, which is served by Grand River.

Our reportable segments reflect the way in which (i) we manage our operations and (ii) management uses the reported financial information to make decisions and allocate resources in connection therewith. The primary assets of each of our reportable segments consist of gathering systems and related property, plant and equipment.

Our financial results are primarily driven by the volumes that we gather, treat and process across our systems and our management of expenses. During 2015, aggregate natural gas volume throughput averaged 1,449 million cubic feet per day ("MMcf/d") and crude oil and produced water volume throughput averaged 55.0 thousand barrels per day ("Mbbl/d"). We generate a substantial majority of our revenue under long-term, primarily fee-based gathering agreements. The fee-based nature of these agreements enhances the stability of our cash flows by limiting our direct commodity price exposure. During the year ended December 31, 2015, substantially all of our revenue, net of pass-through items, was generated from fee-based gathering services. In addition, the vast majority of our gas gathering and processing agreements include areas of mutual interest ("AMIs"). Our AMIs cover more than 1.6 million acres in the aggregate.

Certain of our gathering and processing agreements include minimum volume commitments or minimum revenue commitments (collectively referred to as "MVCs"). To the extent the customer does not meet its MVC, it must make payments to cover the shortfall of required volume throughput not shipped or processed, either on a monthly, quarterly or annual basis. We have designed our MVC provisions to ensure that we will generate a certain amount of revenue from each customer over the life of the respective gathering or processing agreement, whether by collecting gathering or processing fees on actual throughput or from cash payments to cover any MVC shortfall. As of December 31, 2015, we had remaining MVCs totaling 3.7 trillion cubic feet equivalent ("Tcfe," determined using a

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ratio of six thousand cubic feet ("Mcf") of natural gas to one barrel ("Bbl") of crude oil). Our MVCs have a weighted-average remaining life of 8.6 years (assuming minimum throughput volume for the remainder of the term) and average approximately 1.2 Bcfe/d through 2020.

We use a variety of financial and operational metrics to analyze our performance, including among others, throughput volume, revenues, operation and maintenance expenses, EBITDA, adjusted EBITDA, segment adjusted EBITDA and distributable cash flow. 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") and may be defined differently by other companies in our industry. We view each of these operational, GAAP and non-GAAP metrics as important factors in evaluating our profitability and determining the amounts of cash distributions we pay to our unitholders.

For additional information on our results of operations, reportable segment disclosures, EBITDA, adjusted EBITDA and distributable cash flow, see Item 6. Selected Financial Data, MD&A and the consolidated financial statements and notes thereto included in this report.

Our Sponsor and Summit Investments. Energy Capital Partners (our "Sponsor"), 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, including investments in the power generation, midstream oil and gas, electric transmission, environmental infrastructure and energy services sectors.

Summit Investments, which was formed in 2009 by members of our management team and our Sponsor, is the ultimate owner of Summit Midstream GP, LLC (our "general partner"). We are managed and operated by the board of directors and executive officers of our general partner, which is managed and operated by Summit Investments. As a result, 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, thereby controlling SMLP.

In December 2015, Energy Capital Partners approved a unit purchase program of up to $100.0 million of SMLP common units (the "Purchase Program"). Unit purchases commenced in December 2015 and have continued in 2016. Units may be purchased by Summit Investments or Energy Capital Partners in open market transactions, in privately negotiated transactions, or otherwise. The Purchase Program does not require Summit Investments or Energy Capital Partners to purchase a specific number of units. Purchases made under the Purchase Program have not and will not impact the total number of common units outstanding. As February 16, 2016, Summit Investments had acquired 151,160 common units under the Purchase Program while Energy Capital Partners had acquired 2,184,186 common units.

Initial Public Offering. SMLP was formed in May 2012 in anticipation of its IPO. On October 3, 2012, we completed the 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 a continuation of its 2% general partner interest in SMLP and the incentive distribution rights ("IDRs");
- Summit Investments conveyed its remaining interest in Summit Holdings to SMLP in exchange for (i) 10,029,850 common units, (ii) 24,409,850 subordinated units, and (iii) the right to receive cash reimbursement for certain capital expenditures made with respect to the contributed assets; and
- SMLP issued 14,375,000 common units to the public.

Since the IPO, we have issued additional common units and general partner interests in connection with drop down transactions, one third-party acquisition and certain unit-based compensation awards. For additional information, see Notes 1, 10 and 15 to the consolidated financial statements.

Recent Developments

Drop Down Assets Contribution Agreement. On February 25, 2016, we entered into a contribution agreement with Summit Midstream Partners Holdings, LLC ("SMP Holdings"), a wholly owned subsidiary of Summit Investments, (the “Contribution Agreement”) to acquire substantially all of the issued and outstanding membership interests of Summit Midstream Utica, LLC (“Summit Utica”), Meadowlark Midstream Company, LLC (“Meadowlark Midstream”), and Tioga Midstream, LLC ("Tioga"). In addition, we also agreed to acquire substantially all of SMP Holdings' 40.0% joint venture interest in each of Ohio Gathering Company, L.L.C. ("Ohio Gathering") and Ohio

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Condensate Company, L.L.C. (“Ohio Condensate,” and together with Summit Utica, Meadowlark Midstream, Tioga and Ohio Gathering, the “2016 Drop Down Assets”)(the “2016 Drop Down”). The transaction is expected to close in March 2016 (the “Initial Close”).

The consideration to be paid by the Partnership to SMP Holdings for the 2016 Drop Down Assets will consist of (i) a cash payment to SMP Holdings at Initial Close of $360.0 million (the “Initial Payment”) which will be funded with borrowings under our revolving credit facility (see Note 8 to the consolidated financial statements) and (ii) a deferred payment to be paid no later than December 31, 2020 (the “Deferred Payment”). The Deferred Payment will be equal to:

- six-and-one-half (6.5) multiplied by the average adjusted EBITDA, as defined in the Contribution Agreement, of the 2016 Drop Down Assets for 2018 and 2019;
- less the Initial Payment;
- less all capital expenditures incurred for the 2016 Drop Down Assets between the Initial Close and December 31, 2019;
- plus all adjusted EBITDA from the 2016 Drop Down Assets between the Initial Close and December 31, 2019.

At the discretion of the board of directors of our general partner, Summit Midstream GP, LLC, the Deferred Payment can be paid in cash, SMLP common units or a combination thereof. The present value of the Deferred Payment will be reflected as a liability on our balance sheet until paid. Management currently expects that the Deferred Payment will be financed with a combination of (i) net proceeds from the sale of common units by us, (ii) the net proceeds from the issuance of senior unsecured debt by us, (iii) borrowings under our revolving credit facility and/or (iv) other internally generated sources of cash.

The terms of the Contribution Agreement were approved by the conflicts committee of the board of directors of our general partner, which committee consists entirely of independent directors, and by the entire board of our general partner.

Summit Utica. Summit Utica is a natural gas gathering system located in the Appalachian Basin in southeastern Ohio serving producers targeting the Utica and Point Pleasant shale formations. The system is currently in service and under development with fourth quarter of 2015 volume throughput of 75 MMcf/d. Upon full development, it will be composed of 60 miles of low-pressure and high-pressure gathering pipelines and three compressor and dehydration stations with total throughput capacity of 450 MMcf/d. The Summit Utica system gathers and delivers natural gas, primarily under long-term, fee-based contracts which include acreage dedications. XTO Energy, Inc. ("XTO") serves as the anchor customer on the system. The system interconnects with Energy Transfer Partners, L.P.’s Utica Ohio River Pipeline.

Ohio Gathering. Ohio Gathering is a natural gas gathering system located in the core of the Utica Shale in southeastern Ohio which is currently in service and under development. The gathering system spans the condensate, rich-gas, and dry-gas windows of the Utica Shale for multiple producers that are targeting natural gas, condensate and NGL production from the Utica and Point Pleasant formations across Harrison, Guernsey, Belmont, Noble and Monroe counties in Ohio. Currently, the system is composed of more than 250 miles of low-pressure and high-pressure gathering pipeline and offers throughput capacity in excess of 1.9 Bcf/d. Condensate and rich gas production is gathered, compressed, dehydrated and delivered to the Cadiz and Seneca processing complexes, which are owned by a joint venture owned by MPLX LP (“MPLX”) and The Energy and Minerals Group (“EMG”). Dry gas production is gathered, compressed, dehydrated and delivered to a downstream interconnect with TETCO and another third-party pipeline. All gathering services on the Ohio Gathering system are provided pursuant to long-term, fee-based gathering agreements. Gulfport Energy Corporation (“Gulfport”) serves as the anchor customer for Ohio Gathering. In the fourth quarter of 2015, Ohio Gathering gathered an average of 813 MMcf/d of natural gas. A 60.0% non-affiliated joint venture ownership in Ohio Gathering is held by MPLX and EMG.

Ohio Condensate. Ohio Condensate is a 23 Mbbl/d condensate stabilization facility located in the core of the Utica Shale in southeastern Ohio. The facility commenced operations in February 2015 and is underpinned by a long-term, fee-based agreement with Gulfport. Condensate stabilization allows for producers to capture the NGLs that would otherwise flash from condensate in atmospheric conditions. Ohio Condensate is the largest stabilization facility in the Utica Shale Play and will ultimately serve as the origination point for MPLX’s Cornerstone Pipeline which will deliver condensate to Marathon Petroleum’s refinery in Canton, Ohio. In the fourth quarter of 2015, Ohio Condensate handled an average of 18 Mbbl/d of condensate. A 60.0% non-affiliated joint venture ownership in Ohio Condensate is held by MPLX.

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Tioga. The Tioga gathering system is currently in service with 73 miles of crude oil gathering pipeline, 83 miles of produced water gathering pipeline and 79 miles of associated natural gas gathering pipeline. Tioga is located in Williams County, North Dakota and has 20 Mbbl/d of crude oil gathering capacity, 25 Mbbl/d of produced water gathering capacity and 14 MMcf/d of natural gas gathering capacity. All gathering services on the Tioga gathering system are provided pursuant to long-term, fee-based gathering agreements with Hess Corp. ("Hess"), which is primarily targeting crude oil production from the Bakken and Three Forks shale formations. All crude oil, produced water and natural gas gathered on the Tioga system is delivered to downstream pipelines and disposal wells (for produced water) that are owned and operated by Hess. In the fourth quarter of 2015, Tioga gathered an average of 5 Mbbl/d of crude oil, 5 Mbbl/d of produced water, and 7 MMcf/d of natural gas.

Meadowlark Midstream. Meadowlark Midstream is currently composed of two separate gathering systems, including (i) an associated natural gas gathering and processing system located in the Denver-Julesburg ("DJ") Basin serving producers primarily targeting crude oil production from the Niobrara and Codell shale formations in northern Colorado and southern Wyoming (“Niobrara G&P”) and (ii) a crude oil and produced water gathering system located in the Williston Basin serving a producer targeting the Bakken and Three Forks shale formations in northwestern North Dakota (“Blacktail”).

The Niobrara G&P system is currently in service with 91 miles of low-pressure and high-pressure gathering pipeline and a cryogenic natural gas processing plant with processing capacity of 15 MMcf/d; processing capacity is currently being expanded to 20 MMcf/d pursuant to a long-term, fee-based gathering and processing agreement with EOG Resources, Inc. Volume throughput on the Niobrara G&P system averaged 7 MMcf/d in the fourth quarter of 2015. Residue gas is delivered to the Colorado Interstate Gas pipeline and processed NGLs are delivered to the Overland Pass Pipeline.

The Blacktail gathering system is currently in service with 53 miles of crude oil gathering pipeline and 96 miles of produced water gathering pipeline. The Blacktail system is located in Williams County, North Dakota and has 40 Mbbls/d of crude oil throughput capacity and 30 Mbbls/d of produced water throughput capacity. All gathering services on the Blacktail system are provided pursuant to a long-term, fee-based gathering agreement with an independent producer that is primarily targeting crude oil production from the Bakken and Three Forks shale formations. Crude oil on the Blacktail system is currently delivered to the COLT Hub rail facility in Epping, North Dakota and produced water is delivered to various third-party disposal wells located throughout Williams County, North Dakota. In the fourth quarter of 2015, Blacktail gathered an average of 4 Mbbl/d of crude oil and 7 Mbbl/d of produced water.

Fourth Quarter 2015 Distribution. In accordance with the terms of our partnership agreement, the subordination period ends on the first business day after we have earned and paid at least $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. On February 12, 2016, we paid a quarterly cash distribution to our unitholders for the fourth quarter of 2015 of $0.575 per unit, or $2.30 per unit on an annualized basis, on all outstanding units, including the general partner's 2.0% interest. In connection therewith, the subordination period ended on February 16, 2016 and all 24,409,850 subordinated units converted to common units on a one-for-one basis.

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:

- 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 provided under primarily long-term and fee-based contracts with original terms of up to 25 years. Currently, all of the contracts associated with assets owned and being developed by Summit Investments are fee based. We believe that our focus on fee-based revenues with minimal direct commodity exposure is essential to maintaining stable cash flows.
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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 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

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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 to new geographic areas. Our gathering operations in the Marcellus, Bakken, Three Forks and Barnett shale plays and the Piceance Basin currently represent our core business. We intend to diversify our operations into other geographic regions, as a result of the 2016 Drop Down and through both greenfield development projects and acquisitions from third parties.
- 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 that 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 midstream energy infrastructure in unconventional resource basins that we believe will complement our existing 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 resource basins supported by partnerships with large producers. We believe our assets are strategically positioned within the core areas of four established unconventional resource basins. 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 incent 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, 2015 was generated under long-term and fee-based gathering and processing agreements. We believe that long-term, fee-based 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, 2015, we had $944.0 million of total indebtedness and the unused portion of our $700.0 million amended and restated senior secured revolving credit facility (the "revolving credit facility") totaled $356.0 million. Under the terms of our revolving credit facility, our total leverage ratio (total net indebtedness to consolidated trailing 12-month EBITDA, as defined in the credit agreement) was approximately 4.2 to 1.0 at December 31, 2015, 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). Additionally, the total leverage ratio upper limit can be increased from 5.0 to 1.0 to 5.5 to 1.0 at our option, subject to the inclusion of a senior secured leverage ratio (senior secured net indebtedness to consolidated trailing 12-month EBITDA, as defined in the credit agreement) upper limit of 3.75 to 1.0.
- Relationship with a large and committed financial sponsor. Our Sponsor, Energy Capital Partners, is an experienced energy investor with a proven track record of making substantial, long-term investments in high-quality energy assets. In addition to its direct investment in Summit Investments, Energy Capital Partners began purchasing our common units in open market transactions beginning in December 2015. We believe that the relationship with and support of our Sponsor is a competitive advantage as it brings 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.
- Experienced management team with a proven record of asset acquisition, construction, development, operations and integration expertise. Our board members and senior leadership team have extensive energy experience (see Item 10. Directors, Executive Officers and Corporate Governance—Directors and Executive Officers) and a proven track record of identifying, consummating and integrating significant acquisitions in addition to partnering with major producers to construct and develop midstream energy infrastructure.

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Our Midstream Assets
Our midstream assets currently consist of five gathering systems:
- Mountaineer Midstream in northern West Virginia;
- Bison Midstream in northwestern North Dakota;
- Polar and Divide in northwestern North Dakota;
- DFW Midstream in north-central Texas; and
- Grand River in western Colorado and eastern Utah.

We compete with other midstream companies, producers and intrastate and interstate pipelines. Competition for volumes is primarily based on reputation, commercial terms, service levels, access to end-use markets, location and available capacity. We may also face competition to gather production drilled outside of our AMIs and attract producer volumes to our gathering systems. Additionally, we could face incremental competition to the extent we make acquisitions.

We earn revenue by providing gathering, treating and/or processing services pursuant to primarily long-term and fee-based gathering and processing agreements with some of the largest and most active producers in North America. 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 gathering and processing agreements and the gathering systems to which they relate are discussed in more detail below. For additional information, on a consolidated basis and by reportable segment, see the "Results of Operations" section in MD&A.

Areas of Mutual Interest. The vast majority of our gathering and processing agreements contain AMIs. The AMIs generally have original terms of up to 25 years and require that any production by our customers within the AMIs will be shipped on and/or processed by our systems. Our customers do not have leased production acreage that currently cover our entire AMIs but, to the extent that our customers lease additional acreage in the future within our AMIs, any production from wells drilled by our customers within that AMI 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. However, we may choose not to participate in a discretionary opportunity presented by a customer because we believe that the project would not meet our internal return expectations. Under this scenario, 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, we may release the relevant acreage dedication from the AMI.

Minimum Volume Commitments. Many of our gathering and processing agreements contain MVCs pursuant to which our customers agree to ship or process a minimum volume of production on our gathering systems, or, in some cases, to pay a minimum monetary amount, over certain periods during the MVC's term. MVCs, like AMIs, are beneficial in connection with the development and ongoing operation of a gathering system because they provide a contracted minimum revenue stream at start up and limit our direct commodity price exposure during the life of the gathering system. The original terms of our MVCs range up to 15 years and had a weighted-average remaining life of 8.6 years as of December 31, 2015. In addition, certain of our customers have an aggregate MVC, which is a total amount of volume throughput that the customer has agreed to ship and/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.

For additional information on our MVCs, see the "Critical Accounting Estimates" section in MD&A and Notes 2 and 7 to the consolidated financial statements.

Mountaineer Midstream
In June 2013, we acquired certain high-pressure natural gas gathering pipelines and compression assets located in the liquids-rich window of the Marcellus Shale Play from an affiliate of MarkWest Energy Partners, L.P. (“MarkWest,” which has subsequently been acquired by MPLX). We refer to these assets as the Mountaineer Midstream system, or Mountaineer Midstream. Mountaineer Midstream, which operates in the Appalachian Basin, benefits from its location

in Doddridge and Harrison counties in West Virginia where it gathers natural gas under a long-term, fee-

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based contract with Antero. Mountaineer Midstream consists of newly constructed, high-pressure natural gas gathering pipelines ranging from eight inches to 20 inches in diameter and two compressor stations. This liquids-rich natural gas gathering and compression system serves as a critical inlet to MPLX's Sherwood Processing Complex, a primary destination for liquids-rich natural gas in northern West Virginia. The Mountaineer Midstream system currently provides our midstream services for the Marcellus Shale reportable segment.
The following table provides information regarding our Mountaineer Midstream system as of December 31, 2015.

Gathering system	Throughput capacity (MMcf/d)
Mountaineer Midstream (1)	1,050

(1) Contract terms related to AMIs and MVCs are excluded for confidentiality purposes.
In November 2013, we amended our original fee-based natural gas gathering agreement with Antero whereby we agreed to construct approximately nine miles of high-pressure, 20-inch pipeline on the Mountaineer Midstream system (the "Zinnia Loop"). The Zinnia Loop project is underpinned by a 12-year, minimum revenue commitment from Antero, which extends the original term of the contract through 2026.
During the third quarter of 2014, throughput capacity was increased to 1,050 MMcf/d to support Antero's current and future drilling activities. With this expansion, we believe the Mountaineer Midstream system will enhance its strategic position as a primary source of natural gas deliveries to the Sherwood Processing Complex.

Bison Midstream
In June 2013, we acquired certain associated natural gas gathering pipeline, dehydration and compression assets in the Williston Basin from a subsidiary of Summit Investments. We refer to these assets as the Bison Midstream system, or Bison Midstream. Bison Midstream, which is located in Mountrail and Burke counties in northwestern North Dakota, consists of low- and high-pressure pipeline and six compressor stations and includes gathering lines ranging from three inches to 10 inches in diameter. Bison Midstream gathers, compresses and treats associated natural gas that exists in the crude oil stream produced from the Bakken and Three Forks shale formations. These formations are primarily targeted for crude oil production and producer drilling decisions and activity on the Bison Midstream system are based largely on the prevailing price of crude oil. As such, Bison Midstream's volume throughput is also impacted by the prevailing price of crude oil.
Our gas gathering agreements for the Bison Midstream system are long-term, fee-based or percent-of-proceeds, contracts ranging from five years to 15 years. 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 and then delivered to its 2.1 Bcf/d natural gas processing plant in Channahon, Illinois. The Bison Midstream system currently provides our associated natural gas midstream services for the Williston Basin reportable segment.
The following table provides information regarding our Bison Midstream system as of December 31, 2015.

Gathering system	Throughput capacity (MMcf/d)	Approximate AMIs (Acres)	Average daily MVCs through 2020 (MMcf/d)	Remaining MVCs (Bcf)	Weighted-average remaining contract life (Years) (1)
Bison Midstream	32	676,500	8	14	4.6

(1) Weighted average based on total remaining MVC (total remaining MVCs multiplied by average rate).
Volume throughput on the Bison Midstream system is underpinned by MVCs from its anchor customers, EOG and Oasis. In addition to its fee-based gas gathering agreement with EOG and percent-of-proceeds gas gathering agreement with Oasis, the Bison Midstream system is also supported by other fee-based gas gathering agreements. As of December 31, 2015, these gas gathering agreements had AMIs extending through 2027.

Polar and Divide

In May 2015, we acquired certain crude oil and produced water gathering systems and recently commissioned transmission pipelines in the Williston Basin from a subsidiary of Summit Investments. We refer to these assets,

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which commenced operations in the second quarter of 2013, as the Polar and Divide system, or Polar and Divide. Polar and Divide, which is located in Williams and Divide counties in northwestern North Dakota, owns, operates, and is currently developing crude oil and produced water gathering systems and transmission pipelines serving the Bakken and Three Forks shale formations.

Polar and Divide's gathering agreements are long-term, fee-based contracts. Several of these gathering agreements include rate redetermination mechanisms which effectively serve to protect future cash flows by resetting the gathering rate upward in the future in the event that the customer does not attain certain minimum production thresholds. Crude oil that is gathered by Polar and Divide is currently delivered to Crestwood Equity Partners LP's COLT Hub rail facility in Epping, North Dakota and produced water is delivered to third-party disposal facilities located throughout the Williston Basin. The Polar and Divide system currently provides our crude oil and produced water midstream services for the Williston Basin reportable segment.

The following table provides information regarding our Polar and Divide system as of December 31, 2015.

Gathering system	Throughput capacity (Mbbl/d)	Approximate AMIs (Acres)
Polar and Divide (1)	85	192,600

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(1) Contract terms related to MVCs are excluded for confidentiality purposes.

The Polar and Divide system is underpinned by two long-term, fee-based gathering agreements with our anchor customers Whiting and SM Energy. In addition to Whiting and SM Energy, the Polar and Divide system is also supported by other long-term, fee-based gathering agreements and has executed agreements to expand the system to additional customer pad sites.

The Polar and Divide system commissioned the Stampede Lateral, a 46-mile, 10-inch diameter crude oil transmission pipeline, in the first quarter of 2016. The Stampede Lateral has throughput capacity of 60 Mbbl/d and connects to Global Partners LP's Basin Transload rail terminal in Columbus, North Dakota for delivery to east coast markets. In the first quarter of 2016, we also began commissioning the Little Muddy pipeline, a 14-mile, 10-inch diameter crude oil transmission pipeline with an interconnect into Enbridge’s North Dakota Pipeline System in Williams County, North Dakota.

We will continue to develop the Polar and Divide system to extend our gathering reach, increase capacity, increase our receipt and delivery points and maximize volume throughput.

DFW Midstream

In September 2009, we acquired certain natural gas gathering pipeline and compression assets in the Barnett Shale from Energy Future Holdings Corp. ("Energy Future Holdings") and a subsidiary of Chesapeake. We refer to these assets as the DFW Midstream system, or DFW Midstream. DFW Midstream is primarily located in southeastern Tarrant County, in north-central Texas. Southeastern Tarrant County is commonly referred to as the core of the Barnett Shale. As 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. Based on peak month average daily production rates sourced from the Railroad Commission of Texas as of December 2015, this area contains the most prolific wells in the Barnett Shale. For example, the two largest and five of the ten largest wells drilled in the Barnett Shale are connected to the DFW Midstream system.

The DFW Midstream system includes gathering lines ranging from four inches to 30 inches in diameter and is located along existing electric transmission corridors and under both private and public property. Since our initial acquisition, we have expanded throughput capacity by installing electric-drive compression for which we retain a fixed percentage of the natural gas that we receive to offset the costs we incur to operate our electric-drive compressors. DFW Midstream currently has six primary interconnections with third-party, primarily 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 currently provides our midstream services for the Barnett Shale reportable segment.

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The following table provides information regarding our DFW Midstream system as of December 31, 2015.

Gathering system	Throughput capacity (MMcf/d)	Approximate AMIs (Acres)	Average daily MVCs through 2020 (MMcf/d)	Remaining MVCs (Bcf)	Weighted-average remaining contract life (Years) (1)
DFW Midstream	480	108,300	68	120	3.8

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(1) Weighted average based on total remaining MVC (total remaining MVCs multiplied by average rate).

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 AMI 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 other long-term, fee-based gas gathering agreements. In September 2014, we acquired certain natural gas gathering assets which increased throughput capacity on the DFW Midstream system by approximately 30 MMcf/d.

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. 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 in our AMIs. 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 site locations.

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. Furthermore, we believe the production profile of wells drilled within our AMIs 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.

Grand River

In October 2011, we acquired certain natural gas gathering pipeline, dehydration and compression assets in the Piceance Basin from Encana Oil & Gas (USA) Inc., a subsidiary of Encana. We refer to these assets as the Legacy Grand River system. The Legacy Grand River system is primarily located in Garfield County, the largest natural gas producing county in Colorado. It gathers natural gas from the Mesaverde formation and the Mancos and Niobrara shale formations located within the Piceance Basin.

In March 2014, we acquired certain natural gas gathering pipeline, dehydration, compression and processing assets in the Piceance Basin from a subsidiary of Summit Investments. We refer to these assets as the Red Rock Gathering system, or Red Rock Gathering. Summit Investments acquired Red Rock Gathering from a subsidiary of Energy Transfer Partners, L.P. in October 2012. Red Rock Gathering gathers and processes natural gas from the Mesaverde formation and the emerging Mancos and Niobrara shale formations located in western Colorado and eastern Utah. Red Rock Gathering is primarily located in Rio Blanco and Mesa counties in Colorado and Uintah and Grand counties in Utah. The Legacy Grand River and Red Rock Gathering systems have been connected and are managed as a single system. As such, we collectively refer to Legacy Grand River and Red Rock Gathering as the Grand River system, or Grand River.

The Grand River system is primarily a low-pressure gathering system that was originally designed to gather natural gas produced from directional 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 emerging Mancos and Niobrara shale formations, which underlie the Mesaverde formation, via a new medium-pressure gathering 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 1.8 Bcf/d processing facility located in Meeker, Colorado, (ii) Williams Partners L.P.'s Northwest Pipeline system, and (iii)

Kinder Morgan, Inc.'s TransColorado Pipeline system. Processed NGLs from Grand River are injected into Enterprise's Mid-America Pipeline system. In addition, certain of our gas gathering agreements with our Grand River customers permit us to retain condensate volumes that naturally discharge from the liquids-rich natural gas as it moves across our system. The Grand River system currently provides our midstream services for the Piceance Basin reportable segment.

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The following table provides information regarding our Grand River system as of December 31, 2015.

Gathering system	Throughput capacity (MMcf/d)	Approximate AMIs (Acres)	Average daily MVCs through 2020 (MMcf/d)	Remaining MVCs (Bcf)	Weighted-average remaining contract life (Years) (1)
Grand River	1,171	687,400	683	1,878	9

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(1) Weighted average based on total remaining MVC (total remaining MVCs multiplied by average rate).

In October 2011, we entered into a long-term, fee-based gathering agreement with Encana as our anchor customer that included a 25-year AMI 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. Both agreements include long-term acreage dedications and collectively provide more than 375 Bcf of MVCs. Certain of Grand River's other gathering and processing agreements include MVCs with original terms ranging up to 15 years and AMIs with original terms up to 25 years.

In the third quarter of 2015, we executed an expansion agreement with a wholly owned subsidiary of Ursa Resources Group II LLC ("Ursa") to provide approximately 40 MMcf/d of additional throughput capacity in exchange for new MVCs. This new capacity will be utilized by Ursa as it executes its drilling plan over the next two years. In connection with the Black Hills agreement, in March 2014 we commissioned a 20 MMcf/d cryogenic processing plant and related gas gathering infrastructure in the DeBeque, Colorado area to support Black Hills' development of its acreage in the liquids-rich Mancos and Niobrara formations. In connection with the WPX agreement, we agreed to expand our gathering and compression services by constructing gas gathering infrastructure to gather new WPX production in the Rifle, Colorado area. In addition to Encana, WPX, Ursa and Black Hills, the Grand River system is underpinned by other long-term, primarily fee-based gas gathering agreements.

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 Grand River's existing throughput capacity. In addition, we believe that the Grand River system is optimally located for expansion to gather production from the emerging Mancos and Niobrara shale formations.

For additional information relating to our business and gathering systems as well as the recent decline in natural gas and crude oil prices and our commodity price exposure, see the "Trends and Outlook—Natural gas, NGL and crude oil supply and demand dynamics" and "Results of Operations" sections in MD&A.

Regulation of the Natural Gas and Crude Oil 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 Crude 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

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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 and Crude Oil. We believe that our natural 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"). As of December 31, 2015, movements of crude oil on our crude oil pipelines were not subject to FERC jurisdiction under the Interstate Commerce Act ("ICA"); however, on February 1, 2016, Polar Midstream's FERC tariff for interstate movements of crude oil on its Little Muddy pipeline in North Dakota became effective. That tariff will be subject to FERC jurisdiction and oversight. We are also generally subject to FERC's anti-market manipulation regulations. The distinction between federally unregulated natural gas and crude oil pipelines and FERC-regulated natural gas and crude oil 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 pipeline 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 pipeline 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 (the "DOT") 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 or Utah 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 we are required to submit shape files and other information regarding the location and construction of underground gathering pipelines in North Dakota. 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. For example, the North Dakota Industrial Commission is considering rule changes that could result in additional construction and monitoring requirements for all pipelines, including, but not limited to, those that transport produced water.
Natural gas, crude oil and produced water 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, which establishes federal safety standards for the design, construction, operation and maintenance of natural gas and crude oil 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

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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 DOT has delegated the implementation of safety requirements to the Pipeline and Hazardous Materials Safety Administration ("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 DOT regulations for intrastate pipelines. Among the regulations applicable to us, 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 gathering system is located. While the majority of our pipelines meet the DOT definition of gathering lines and are thus currently exempt from the integrity management requirements of 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.

In October 2015, PHMSA proposed changes to its pipeline safety regulations that would significantly extend the integrity management requirements to previously exempt pipelines and would impose additional obligations on pipeline operators that are already subject to the integrity management requirements. PHMSA’s proposed rule would also require annual reporting of safety-related conditions and incident reports for all gathering lines and gravity lines, including pipelines that are currently exempt from PHMSA regulations. PHMSA issued a separate regulatory proposal in July 2015 that would impose pipeline incident prevention and response measures on pipeline operators. PHMSA has also issued an Advisory Bulletin providing guidance on verification of records related to pipeline maximum allowable operating pressure. Pipelines that do not meet 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, treating and/or processing of natural gas and the gathering of crude oil and produced water 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;
- 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

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- 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 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 solid and hazardous wastes and other substances, including 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. Although we generate minimal hazardous waste, 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.

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 facilities, and also impose various monitoring, control 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 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 crude oil and natural gas industry. Through the same rulemaking, the EPA revised several existing regulations 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 required a number of modifications to our operations, including the installation of new equipment to control emissions from VOC emitting tanks at initial startup. To date, compliance with such rules has not resulted in significant costs.

On August 18, 2015, the EPA submitted revisions to its 2012 NSPS for the crude oil and natural gas industry to reduce emissions of greenhouse gases, most notably methane, along with smog-forming VOCs. The updates would add methane to the pollutants covered by the rule, along with requirements for detecting and repairing leaks at gathering and boosting stations, and requirements to limit emissions from pneumatic pumps used at gathering and boosting stations. The updates are expected to be finalized mid-year 2016.

On October 1, 2015, the EPA issued a new lower national ambient air quality standard (“NAAQS”) for ozone. The previous ozone standard was set at 75 parts per billion ("ppb"). The revised standard has been lowered to 70 ppb. The lowered ozone NAAQS could result in a significant expansion of ozone nonattainment areas across the United States, including areas in which we operate, which could subject us to increased regulatory burdens in the form of more stringent emission controls, emission offset requirements, and increased permitting delays and costs. Impacts from the new standard have not yet been determined, as states are still in the process of incorporating the new standard into their respective state implementation plans. We will continue to monitor developments to determine if any adverse effects on our operations can be expected.

In addition, in February 2014, the Colorado Department of Public Health and Environment’s Air Quality Control Commission finalized regulations imposing stringent new requirements relating to air emissions from oil and gas facilities in Colorado. These new Colorado rules include storage tank control, monitoring, recordkeeping and reporting requirements as well as leak detection and repair requirements for both well production facilities and compressor stations and associated equipment. The new requirements went into effect January 2015 and we will continue to evaluate how these requirements impact our business.

Water Discharges. The Clean Water Act, and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into regulated waters, which impacts 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. 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. These permits require us to control storm water runoff from some of our 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.

Oil Pollution Act. The Oil Pollution Control Act (the "OPA") requires 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. Certain of our facilities are classified as SPCC-regulated facilities. We believe that they are in substantial compliance with all applicable requirements of OPA.

Hydraulic Fracturing. Hydraulic fracturing is an important and increasingly common practice that is used to stimulate production of natural gas and/or crude oil from dense subsurface rock formations, and is primarily presently regulated by state agencies. However, Congress has in the past and may in the future consider legislation

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to regulate hydraulic fracturing by federal agencies. Many states have already adopted laws and/or regulations that require disclosure of the chemicals used in hydraulic fracturing, and are considering legal requirements that could impose more stringent permitting, disclosure and well construction requirements on oil and/or natural gas drilling activities. The EPA is also moving forward with various related regulatory actions, including approving new regulations requiring green completions of hydraulically-fractured wells and corresponding reporting requirements that went into effect in 2015. We do not believe these new regulations will have a direct effect on our operations, but because natural gas and/or crude oil production using hydraulic fracturing is growing rapidly in the United States, if new or more stringent federal, state or local legal restrictions relating to such drilling activities or to the hydraulic fracturing process are adopted, this could result in a reduction in the supply of natural gas and/or crude oil.

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 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 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 GHG emissions above the reporting thresholds. On October 22, 2015, the EPA issued revisions to Subpart W of the GHG reporting rule to include reporting requirements for gathering and booster stations, onshore natural gas transmission pipelines, and completions and workovers of oil wells with hydraulic fracturing. This development will result in increased monitoring and reporting for our operations and for upstream producers for whom we provide midstream services. The EPA continues to consider additional climate change requirements for the energy industry. We will continue to monitor any such additional requirements to determine if they 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.

Other Information

Employees. SMLP does not have any employees. All of the employees required to conduct and support its operations are employed by Summit Investments, 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, 2015, Summit Investments employed

294 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.

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Availability of Reports. We make certain filings with the Securities and Exchange Commission (the "SEC"), including, among other filings, our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments and exhibits to those reports, available free of charge through our 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. Our press releases and recent investor presentations are also available on our website.

Item 1A. Risk Factors.

Item 1A. Risk Factors is divided into the following sections:

Risks Related to our Business

Our principal business strategy is to increase the amount of cash distribution we make to our unitholders over time. We may not have sufficient cash from operations following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements of expenses incurred on our behalf by our general partner, to enable us to pay the minimum quarterly distribution ("MQD") or any distribution to holders of our common units.

To pay the MQD of $0.40 per unit per quarter, or $1.60 per unit on an annualized basis, we will require available cash of $27.1 million per quarter, or $108.5 million per year (based on units outstanding, as of December 31, 2015). We may not have sufficient available cash from operating surplus each quarter to pay the MQD. 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 volumes we gather, treat and process;
- the level of production of natural gas and crude oil (and associated volumes of produced water) 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;
- 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 areas of operation;
- changes in the level of our operating, maintenance and general and administrative expenses;
- 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 and maintenance 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, maintenance and general and administrative expenses, including reimbursements of expenses incurred on our behalf by our general partner;
- the cost of acquisitions, if any;

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- 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;
- not receiving anticipated shortfall payments from our customers; and
- other business risks affecting our cash levels.

We depend on certain 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.

Certain 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 these 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.

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.

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 and associated liquidity 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, including making any required shortfall payments.

The policies and procedures we use to manage our exposure to credit risk, such as credit analysis, credit monitoring and, if necessary, 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, have limited financial resources and/or have recently experienced a rating agency downgrade 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 could have a negative impact on our counterparties, which, in turn, could have a negative impact on their ability to meet their obligations to us.

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

Adverse developments in our 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 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. Due to our limited industry and geographic diversity, adverse developments in the natural gas and crude oil

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industries or in our existing areas of operation could have a significantly greater impact on our financial condition, results of operations and cash flows.

Significant prolonged weakness in natural gas, NGL and crude oil prices could reduce throughput on our systems and materially adversely affect our revenues and cash available to make cash distributions to our unitholders over the long term.

The current level of natural gas, NGL and crude oil prices has had a negative impact on exploration, development and production activity in our areas of operation. Unchanged or lower natural gas, NGL and crude oil prices over the long term could result in a further decline in the production of natural gas and crude oil, thereby resulting in reduced throughput on our gathering systems. The price of natural gas has been at historically low levels for an extended period of time. In addition, the price of crude oil has experienced a significant decline since the fall of 2014 in response to a global supply surplus.

Additionally, due to the extended period of historically low natural gas prices and decline in NGL and crude oil prices, certain of our customers in each of our areas of operations have, and others could, reduce drilling activity and capital expenditure budgets. If natural gas, NGL and/or crude oil 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.

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 that we gather and process could materially adversely affect our business and operating results.

The customer volumes that support our business depend on the level of production from natural gas and crude oil 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 volume throughput. The primary factors affecting our ability to obtain new sources of volume throughput include (i) the level of successful drilling activity in our areas of operation and (ii) our ability to compete for new volumes on our systems.

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 other hydrocarbon products, including NGLs;
- demand for crude oil, natural gas and other hydrocarbon products, including 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 and geopolitical 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;

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- 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 and other hydrocarbon products, including NGLs.

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 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 could 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 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 and/or new gathering opportunities with existing customers, our ability to increase the throughput on our gathering systems will be dependent on receiving increased volumes from our existing customers. Our customers are not obligated to provide additional volumes to our gathering 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.

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

Our gathering and processing agreements were designed to generate stable cash flows for us over the life of the MVC contract term while also minimizing direct commodity price risk. Under certain of these MVCs, our customers agree to ship a minimum volume on our gathering systems or send a minimum volume to our processing plants or, in some cases, to pay a minimum monetary amount, over certain periods during the term of the MVC. In addition, the majority of our gathering and processing agreements also include an aggregate MVC, which is a total amount that the customer must flow on our gathering system or send to our processing plants (or an equivalent monetary amount) over the MVC term. If a customer's actual throughput volumes are less than its minimum volume commitment for the contracted measurement 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 fee. To the extent that a customer's actual throughput volumes are above or below its MVC for the applicable contracted measurement period, many of our 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, which could 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.

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

We have not obtained and do not intend to obtain independent evaluations of all of the reserves connected to our systems. Moreover, even if we did obtain independent evaluations of all of the 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 volumes, 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 operations, some of which are large companies that have greater financial, managerial and other resources than we do. In addition, some of our competitors may have assets in closer proximity to natural gas and crude oil supplies and may have available idle capacity in existing assets that would not require new capital investments for use. Our competitors may expand or construct gathering systems that would create additional competition for the services we provide to our customers. Because our customers do not have leases that cover the entirety of our areas of mutual interest, non-customer producers that lease acreage within any of our areas of mutual interest may choose to use one of our competitors for their gathering and/or processing service needs.

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.

Our gathering, treating and processing contracts have terms of various durations. As these contracts expire, we may have to negotiate extensions or renewals with existing customers or enter into new contracts with other 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 in our areas of operation;
- the macroeconomic factors affecting gathering, treating 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 areas of operation 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.

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 gathering systems connect to third-party pipelines and other midstream facilities, such as processing plants, rail terminals and produced water disposal facilities. The continuing operation of such third-party pipelines and other

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midstream facilities is not within our control. These pipelines and other midstream facilities may become unavailable due to issues including, but not limited to, testing, turnarounds, line repair, reduced operating pressure, lack of operating capacity, regulatory requirements, curtailments of receipt or deliveries due to insufficient capacity or because of damage from other operational hazards. In addition, we do not have interconnect agreements with all of these pipelines and other facilities and the agreements we do have may be terminated in certain circumstances and/or 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, crude oil and produced water that we gather and/or 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. 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 have a relatively limited history of operating our assets. There may be historical occurrences or latent issues regarding our pipeline systems of which we 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.

Crude oil and natural gas production in certain areas in which we operate 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, especially in North Dakota and West Virginia, can be severe and can adversely affect crude oil and natural 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 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, treating and processing systems, including interruptions in service. These types of interruptions could negatively impact our ability to meet our contractual obligations to our customers and thereby give rise to certain termination rights and/or the release of dedicated acreage. Any resulting terminations or releases could materially adversely 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 provide gathering, treating or processing services, could 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 production volumes that do not comply with applicable specifications; and
- inadequate transportation or market access to support production volumes, including lack of pipeline, rail terminals, produced water disposal facilities and/or third-party processing capacity.

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Our business involves many hazards and operational risks, some of which may not be fully covered by insurance. If a significant incident or event occurs for which we are not adequately insured or if we fail to recover all anticipated insurance proceeds for significant incidents 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 operation of gathering, treating and processing systems, including:

- damage to pipelines, processing plants, compression assets, 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 or losses resulting from 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 portions or all of our gathering systems. Potential customer impacts arising from service interruptions on segments of our gathering systems could include limitations on our ability to satisfy customer requirements, obligations to temporarily waive minimum volume commitments 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.

Our insurance coverage is provided by policies that cover all of our assets and those of Summit Investments and its non-SMLP subsidiaries. Therefore, it is possible that an incident, or incidents, at those subsidiaries could exhaust claim capacity and leave SMLP and its subsidiaries exposed to risk of loss should they experience a loss during the same policy cycle. In addition, 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 incident 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 and/or claims by Summit Investments or its non-SMLP subsidiaries may increase rates on all of the insured-asset group, including those owned by SMLP and its subsidiaries. As a result of industry or market conditions, some of which are beyond our control, 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 in the event of any 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 third parties, our future growth will be affected, and the acquisitions we do make may reduce, rather than increase, our cash generated from operations. Our ability to grow depends, in part, on our ability to make acquisitions that increase our cash generated from operations. The acquisition component of our strategy also relies, in part, on the continued divestiture of midstream 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 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

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governmental or third-party consents or for any other reason, then our future growth and ability to increase cash distributions on a per-unit basis will be limited. If we are unable to acquire assets from third parties in the near or long term it may adversely affect our ability to grow our business. 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. Any acquisition involves potential risks, including, among other things:

- mistaken assumptions about volumes, revenue and costs, including synergies and potential growth;
- an inability to secure adequate customer commitments to use the acquired systems or facilities;
- the risk that natural gas or crude oil reserves expected to support the acquired assets may not be of the anticipated magnitude or may not be developed as anticipated;
- an inability to successfully integrate 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 debt or equity capital;
- 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;
- production declines higher than anticipated; and
- facilities being properly constructed.

If we consummate any future acquisitions, our capitalization, results of operations and future growth 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 deciding to engage in these future acquisitions, which may reduce, rather than increase, our cash generated from operations.

Following the initial closing of the 2016 Drop Down, which is expected to occur in March 2016, substantially all of the assets owned by Summit Investments will be contributed to the Partnership, and, as a result, our growth strategy will become more dependent on making acquisitions from third parties. This shift from a growth strategy focused, primarily, on acquisitions from Summit Investments, to one focused, primarily, on third-party acquisitions could materially adversely affect our ability to grow our operations and increase our cash distributions to our unitholders.

We may fail to successfully integrate gathering system acquisitions 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 future gathering system acquisitions could be a complex, time-consuming and costly process, particularly if the acquired assets significantly increase our size and/or diversify the geographic areas in which we operate or the service offerings that we provide.

The 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 above or in the immediately preceding risk factor or unanticipated liabilities or costs were to materialize with respect to future 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 and ability to make cash distributions to unitholders 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. 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.

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Such expansion projects may also require the expenditure of significant amounts of capital, and financing, traditional or otherwise, may not be available on economically acceptable terms or at all. If we undertake these projects, our revenue may not increase immediately upon the expenditure of funds for a particular project and they may not be completed on schedule, at the budgeted cost, or at all.

Moreover, we could construct facilities to capture anticipated future production growth in a region where 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 due to 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 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 gathering and processing agreements. Limited access and/or availability of the debt and equity 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 gathering and processing agreements also require us to spend significant amounts of capital, 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 debt or equity 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 production volumes 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 a contractual commitment from our Sponsor or Summit Investments 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.

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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 common 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, 2015, we had $944.0 million of total indebtedness and the unused portion of our $700.0 million amended and restated revolving credit facility totaled $356.0 million. Contingent upon and concurrent with the Initial Close of the 2016 Drop Down, the borrowing capacity of our amended and restated revolving credit facility will increase to $1.25 billion and we will draw $360.0 million to fund the Initial Payment. Our future level of debt could have significant consequences, including among other things:

- limiting our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes and/or obtaining such financing on favorable terms;
- reducing our funds available for operations, future business opportunities and cash distributions to unitholders by that portion of our cash flow required to make interest payments on our debt;
- increasing our vulnerability to competitive pressures or a downturn in our business or the economy generally; and
- limiting our flexibility in responding to changing business and economic conditions.

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 indentures 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 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 senior notes indentures 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 indentures restrict our ability to, among other things:

- incur or guarantee certain additional debt;
- make certain cash distributions on or redeem or repurchase certain units;
- make certain investments and acquisitions;
- make certain 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 transaction; and
- transfer, sell or otherwise dispose of certain assets.

Our amended and restated revolving credit facility and senior notes indentures also contain covenants requiring us to maintain certain financial ratios and meet certain tests. 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 senior notes indentures 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

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our amended and restated revolving credit facility or senior notes indentures could result in a default or an event of default that could enable our lenders or senior 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 directly exposed to changes in crude oil, natural gas and NGL prices, and our exposure may increase in the future.

We generate a substantial majority of our revenues pursuant to primarily long-term and fee-based gathering and processing agreements under which we are paid based on the volumes that we gather and/or process rather than the value of the underlying commodity or related byproduct. 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 gathering and processing agreements. For example, we have percent-of-proceeds contracts with certain natural gas producer customers and we may, in the future, enter into additional percent-of-proceeds contracts with these customers or other customers, which would increase our exposure to commodity price risk, as the revenues generated from those contracts directly correlate with the fluctuating price of the underlying commodities.

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, (ii) the sale of condensate volumes that we retain at Grand River, and (iii) the sale of processed natural gas and NGLs pursuant to our percent-of-proceeds contracts with certain of our customers on the Bison Midstream and Grand River systems. 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 and other NGLs. Furthermore, we may acquire or develop additional midstream assets in the future that have a greater exposure to fluctuations in commodity price risk than our current operations. Future exposure to the volatility of natural gas and crude oil 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 revenues to decline or our operation and maintenance expenses to increase.

Various aspects of our operations are subject to regulation by the various federal, state and local departments and agencies that have jurisdiction over participants in the energy industry. The regulation of our activities and the natural gas and crude oil industries frequently change as they are reviewed by legislators and regulators. In 2014, the North Dakota Industrial Commission began to oversee the integrity and location of underground gathering pipelines that are not monitored by other state or federal agencies and is considering additional rule changes that could result in additional construction and monitoring requirements for all pipelines, including, but not limited to, those that transport produced water. In 2015, the DOT, through PHMSA, proposed changes to its hazardous liquid pipeline regulations that would extend pipeline safety regulation to previously unregulated 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 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 operation and maintenance costs or both.

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

Hydraulic fracturing is an important and increasingly common practice that is used to stimulate production of natural gas and/or crude oil from dense subsurface rock formations, and is primarily regulated by state agencies. However, Congress has in the past and may in the future consider legislation to regulate hydraulic fracturing by federal agencies. Many states have already adopted laws and/or regulations that require disclosure of the chemicals used in hydraulic fracturing, and are considering legal requirements that could impose more stringent permitting, disclosure and well construction requirements on crude oil and/or natural gas drilling activities. The Environmental Protection Agency ("EPA") is also moving forward with various related regulatory actions, including approving, on April 17, 2012, new regulations requiring, among other matters, green completions of hydraulically-fractured wells. The requirement to conduct green completions, and the corresponding notification and reporting requirements, went into effect in 2015. If new or more stringent federal, state or local legal restrictions relating to such drilling activities or to the hydraulic fracturing process are adopted, this could result in a reduction in the supply of natural gas and/or crude oil, which could adversely affect our results of operations and financial condition.

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 natural gas pipeline facilities qualify as gathering facilities that are exempt from the jurisdiction of the Federal Energy Regulatory Commission ("FERC"), the Natural Gas Act ("NGA") and the Natural Gas Policy Act of 1978 (the "NGPA"). As of December 31, 2015, movements of crude oil on our crude oil pipelines were not subject to FERC jurisdiction under the Interstate Commerce Act (“ICA”); however, on February 1, 2016, Polar Midstream's FERC tariff for interstate movements of crude oil on its Little Muddy pipeline in North Dakota will become effective (the "Little Muddy Tariff"). The Little Muddy Tariff will be subject to FERC jurisdiction and oversight. We are also generally 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 (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 natural gas and crude oil pipelines and FERC-regulated natural gas and crude oil pipelines has been the subject of extensive litigation and is determined by FERC on a case-by-case basis. 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 natural gas gathering operations or crude oil operations beyond the Little Muddy pipeline become subject to FERC jurisdiction under the NGA, the NGPA or the ICA, 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, the NGPA or the ICA, 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 FERC.

We are subject to state and local regulation regarding the construction and operation of our gathering, treating and processing 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 natural gas and crude oil we may gather, treat and process. Ratable take statutes and regulations generally require gatherers to take natural gas and crude oil 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 and crude oil for gathering, treating and processing, including state regulation of production rates, maximum daily production allowable from 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 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, including, for example, the Clean Air Act, the Comprehensive Environmental Response, Compensation, and Liability Act; the Clean Water Act; the Oil Pollution Act; the Resource Conservation and Recovery Act; the Endangered Species Act; and the Toxic Substances Control Act.
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. For example in October 2015, the EPA lowered the existing national ambient air quality standard ("NAAQS") for ozone, which could subject us to increased regulatory burdens in the form of more stringent emissions controls, emission offset requirements and increased permitting delays and costs. And in August 2015, the EPA proposed additional regulations to reduce emissions of methane and VOCs from the crude oil and natural gas sector. 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 DOT, through PHMSA, 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 DOT regulations for intrastate pipelines. Among the regulations applicable to us, 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 DOT definition of gathering lines and are thus currently exempt from 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;

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- repair and remediate pipelines as necessary;
- adopt and maintain procedures, standards and training programs for control room operations; and
- implement preventive and mitigating actions.

In October 2015, PHMSA proposed changes to its pipeline safety regulations that would significantly extend the integrity management requirements to previously exempt pipelines and would impose additional obligations on pipeline operators that are already subject to the integrity management requirements. PHMSA's proposed rule would also require annual reporting of safety-related conditions and incident reports for all gathering lines and gravity lines, including pipelines that are currently exempt from PHMSA regulations. PHMSA issued a separate regulatory proposal in July 2015 that would impose pipeline incident prevention and response measures on pipeline operators. Acceptance of the PHMSA proposals could have a material adverse effect on our operations and costs of transportation services.
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 services we provide.

In recent years, the U.S. Congress has considered legislation to restrict or regulate emissions of greenhouse gases ("GHGs"), 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 GHG emissions issues. In addition, almost half of the states, either individually or through multi-state regional initiatives, have begun to address GHG emissions, primarily through the planned development of emission inventories or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and 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 GHG emission reduction goal is achieved. Depending on the scope of a particular program, we could be required to purchase and surrender allowances for GHG 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 GHG emissions, such as electric power plants, it is possible that certain components of our operations, such as our gas-fired compressors, could become subject to state-level GHG-related regulation.
Independent of Congress, the EPA has begun to adopt regulations under its existing Clean Air Act authority. In 2009, the EPA published its findings that emissions of GHGs present an endangerment to public health and the environment because emissions of such gases are contributing to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA adopted regulations that, among other things, establish Prevention of Significant Deterioration ("PSD") construction and Title V operating permit reviews for certain large stationary sources of GHG emissions. In addition, in September 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG-emitting sources in the United States beginning in 2011 for emissions in 2010. In November 2010, the EPA published a final rule expanding the reporting requirement to include onshore and offshore crude oil and natural gas systems beginning in 2012, which was again expanded in October 2015 to include additional crude oil and natural gas systems like gathering and boosting activities and onshore natural gas transmission pipelines. These rules require that we report our GHG emissions for certain of our assets. Further, in December 2015, over 190 countries, including the United States, reached an agreement to reduce global GHG emissions. If and to the extent the United States implements this agreement, it could have a material adverse effect on our business and that of our customers.

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

The implementation of 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 ("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 market participants, such as swap dealers, the clearing of certain swaps through central counterparties, the execution of certain swaps on designated contract markets or swap execution facilities, mandatory margin requirements for uncleared swaps, and the reporting and recordkeeping of swaps. While most of the regulations have been promulgated and are already in effect, the rulemaking and implementation process is still ongoing. Moreover, CFTC continues to refine its initial rulemakings under the Dodd-Frank Act. As a result, we cannot yet predict the ultimate effect of the rules and regulations on our business and while most of the regulations have been adopted, any new regulations or modifications to existing regulations could increase the cost of derivative contracts, limit 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 CFTC has proposed federal position limits on certain core futures and equivalent swaps contracts in the major energy and other markets, with exceptions for certain bona fide hedging transactions provided that various conditions are satisfied. If finalized, the position limits rule and its companion rule on aggregation among entities under common ownership or control may have an impact on our ability to hedge our exposure to certain enumerated commodities.

In 2013, the CFTC implemented final rules regarding mandatory clearing of certain classes of interest rate swaps and certain classes of index credit default swaps. Mandatory trading on designated contract markets or swap execution facilities of certain interest rate swaps and index credit default swaps also began in 2014. At this time, the CFTC has not proposed any rules designating other classes of swaps, including physical commodity swaps, for mandatory clearing. The CFTC and prudential banking regulators also recently adopted mandatory margin requirements on uncleared swaps between swap dealers and certain other counterparties. Although we may qualify for a commercial end-user exception from the mandatory clearing, trade execution and uncleared swaps margin requirements, mandatory clearing and trade execution requirements and uncleared swaps margin requirements applicable to other market participants, such as swap dealers, may affect the cost and availability of the swaps that we use for hedging.

Under the Dodd-Frank Act, the CFTC is also directed generally to prevent price manipulation and fraud in the following two markets: (a) physical commodities traded in interstate commerce, including physical energy and other commodities, as well as (b) financial instruments, such as futures, options and swaps. Pursuant to the Dodd-Frank Act, the CFTC has adopted additional anti-market manipulation, anti-fraud and disruptive trading practices regulations that prohibit, among other things, fraud and price manipulation in the physical commodities, futures, options and swaps markets. Should we violate these laws and regulations, we could be subject to CFTC enforcement action and material penalties, and sanctions.

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 CFTC has finalized an interpretation clarifying whether certain forwards with volumetric optionality are regulated as forwards or qualify as options on commodities and therefore swaps. This interpretation may have an impact on our ability to enter into certain forwards or may impose additional requirements with respect to certain transactions.

In addition to the Dodd-Frank Act, the European Union and other foreign regulators have adopted and are implementing local reforms generally comparable with the reforms under the Dodd-Frank Act. Implementation and enforcement of these regulatory provisions may reduce our ability to hedge our market risks with non-U.S. counterparties and may make any transactions involving cross-border swaps more expensive and burdensome.

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Additionally, the lack of regulatory equivalency across jurisdictions may increase compliance costs and make it more costly to satisfy regulatory obligations.

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 renegotiating 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 IT systems or 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 depends on our continued ability to attract and retain highly skilled management personnel with midstream energy industry experience and competition for these persons in the midstream energy 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.

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

The operation of gathering, treating and processing systems 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.

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Risks Inherent in an Investment in Us

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

Summit Investments controls our general partner and has authority to appoint all of the officers and directors of our general partner, some of whom will also be officers, directors or principals of Energy Capital Partners, the entity that controls 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. Conflicts of interest will arise between 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 Summit Investments and its owners over our interests and the interests of our unitholders. These conflicts include the following situations, among others:

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

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

If Energy Capital Partners, the private equity firm that controls Summit Investments, consummates a transaction involving a sale or other disposition of its interests in Summit Invesments, the transaction would result in a change of control of SMLP because Summit Investments indirectly owns and controls our general partner. In addition, our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, our partnership agreement does not restrict the ability of Summit Investments to transfer all or a portion of its ownership interest in our general partner to a third party. The owner of Summit Investments, or new members of our general partner, as applicable, would then be in a position to replace the board of directors and officers of our general partner with their 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.

Our general partner's IDRs may be transferred to a third party without unitholder consent.

Our general partner may transfer the IDRs it owns to a third party at any time without the consent of our unitholders. If our general partner transfers the IDRs 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 IDRs. For example, a transfer of the IDRs by our general partner could reduce the likelihood of Summit Investments selling or contributing additional midstream assets to us, as Summit Investments would have less of an economic incentive to grow our business, which in turn would impact our ability to grow our asset base.

Our Sponsor is not limited in its ability to compete with us and is 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.

Our Sponsor has significantly greater resources than us and has experience making investments in midstream energy businesses. Although it controls Summit Investments, our Sponsor may compete with us for investment opportunities and may own interests in entities that compete with us. Energy Capital Partners is not prohibited from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, Energy Capital Partners and Summit Investments 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.

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 Summit Investments and our Sponsor and its 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 amount of cash we have available for distribution to holders of our common 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 report net losses for GAAP purposes and may not make cash distributions during periods when we report net income for GAAP purposes.

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.

Of the 42,062,644 common units outstanding at December 31, 2015, Summit Investments beneficially owned 5,444,731 common units and 24,409,850 subordinated units, which converted to common units on a one-for-one basis on February 16, 2016. In connection with the Purchase Program, a subsidiary of Energy Capital Partners had acquired 2,184,186 common units as of February 16, 2016. An investor may not be able to resell its common units at or above its acquisition price. Additionally, limited 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 among others:

- our quarterly distributions;
- our quarterly or annual earnings or those of other companies in our industry;
- the loss of a large customer;
- announcements by our customers or others regarding our customers or changes in our customers' credit ratings, liquidity position, leverage profile and/or other financial or credit-related metrics;
- announcements by our competitors of significant contracts or acquisitions;
- changes in accounting standards, policies, guidance, interpretations or principles;
- general economic and geopolitical conditions;
- the failure of securities analysts to cover our common units or changes in financial estimates by analysts;
- future sales of our common units, including those held by Summit Investments and its subsidiaries; and
- other factors described in these Risk Factors.

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 GAAP. 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 could 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.

Our partnership agreement replaces our general partner's fiduciary duties to unitholders 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

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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, among others:

- 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 IDRs 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

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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, our amended and restated revolving credit facility or senior notes indentures 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 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.) As of December 31, 2015, Summit Investments beneficially owned 5,444,731 common units out of 42,062,644 outstanding common units and all of our 24,409,850 subordinated units which converted to common units on a one-for-one basis on February 16, 2016. Additionally, in connection with the Purchase Program, a subsidiary of Energy Capital Partners had acquired 2,184,186 common units as of February 16, 2016.

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

Prior to making any distribution on our common units, we will reimburse our general partner and its affiliates, including Summit Investments, for expenses they incur and payments they make on our behalf. Under our partnership agreement, we will reimburse our general partner and its affiliates for certain expenses incurred on our behalf, including, without limitation, salary, bonus, incentive compensation and other amounts paid to our general partner's employees and executive officers 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 to our general partner and its affiliates will reduce the amount of available cash to pay cash distributions to our unitholders.

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Our general partner may elect to cause us to issue common units to it in connection with a resetting of the MQD and the target distribution levels related to our general partner's IDRs 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 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 MQD 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 MQD), and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset MQD. 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 IDRs 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 IDRs 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 IDRs.

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.

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 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 has been chosen by Summit Investments. Furthermore, if our unitholders are dissatisfied with the performance of our general partner, they have little ability to remove our general partner. As a result of these limitations, the price at which the common units 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 our 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 may not be able to remove our general partner without its consent.

The vote of the holders of at least 66 2/3% of all outstanding limited partner units voting together as a single class is required to remove our general partner. As of December 31, 2015, Summit Investments beneficially owned

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5,444,731 common units out of 42,062,644 outstanding common units and all of our 24,409,850 subordinated units which converted to common units on a one-for-one basis on February 16, 2016, representing a voting block sufficient to prevent the other limited partners from removing our general partner. Additionally, in connection with the Purchase Program, a subsidiary of Energy Capital Partners had acquired 2,184,186 common units as of February 16, 2016.

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

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

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

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

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 the amount payable to holders of IDRs is based on a percentage of the total cash available for distribution, the distributions to holders of IDRs will increase even if the per-unit distribution on common units remains the same;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

Summit Investments or our Sponsor 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, 2015, Summit Investments beneficially owned 5,444,731 common units out of 42,062,644 outstanding common units and all of our 24,409,850 subordinated units, which converted to common units on a one-for-one basis on February 16, 2016. We have agreed to provide Summit Investments with certain registration rights pursuant to the terms of our partnership agreement. Additionally, in connection with the Purchase Program, a subsidiary of Energy Capital Partners had acquired 2,184,186 common units as of February 16, 2016. The sale of any 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.

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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, 2015, Summit Investments beneficially owned 5,444,731 common units out of 42,062,644 outstanding common units and all of our 24,409,850 subordinated units, which converted to common units on a one-for-one basis on February 16, 2016. Additionally, in connection with the Purchase Program, a subsidiary of Energy Capital Partners had acquired 2,184,186 common units as of February 16, 2016. As such, our general partner and its affiliates controlled a total of 32,038,767 common units, or 48.2% of our common units outstanding as of February 16, 2016.

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 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 or 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.

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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 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 U.S. 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 changes or differing interpretations at any time. For example, the Obama administration’s budget proposal for fiscal year 2016 recommends that certain publicly traded partnerships earning income from activities related to fossil fuels be taxed as corporations beginning in 2021. From time to time, members of Congress propose and consider such substantive changes to the existing federal income tax laws that affect publicly traded partnerships. If successful, the Obama administration’s proposal or other similar proposals could eliminate the qualifying income exception to the treatment of all publicly traded partnerships as corporations, upon which we rely for our treatment as a partnership for U.S. federal income tax purposes.
In addition, the U.S. Treasury Department and the IRS have issued proposed regulations concerning which activities give rise to qualifying income within the meaning of Section 7704 of the Internal Revenue Code ("IRC"). We do not believe the proposed regulations affect our ability to qualify as a publicly traded partnership. However, finalized regulations could modify the amount of our gross income that we are able to treat as qualifying income for the purposes of the qualifying income requirement.
Any modification to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible for us to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

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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.

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 it sells will, in effect, become taxable income to the unitholder if it sells such common units at a price greater than 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 it receives from the sale.

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

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

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

Because we cannot match transferors and transferees of common units and because of other reasons, we will adopt depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to 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 between transferors and transferees of our units each month based upon the ownership of our units on the first business day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge aspects of our proration method, and, if its challenge is successful, we would be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first business day of each month, instead of on the basis of the date a particular unit is transferred. The U.S. Treasury Department and the IRS recently issued Treasury Regulations that permit publicly traded partnerships to use a monthly simplifying convention that is similar to our, but they do not specifically authorize all aspects of the proration method we have adopted. If the IRS were to successfully challenge this method, we could 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 have adopted certain valuation methodologies in determining a unitholder's allocations of income, gain, loss and deduction. The IRS may challenge these methodologies or the resulting allocations, and such a challenge could adversely affect the value of our common units.

In determining the items of income, gain, loss and deduction allocable to our unitholders, in certain circumstances, including when we issue additional units, we must determine the fair market value of our assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we make many fair market value estimates using a methodology based on the market value of our common units as a means to measure the fair market value of our assets. The IRS may challenge these valuation methods and the resulting allocations of income, gain, loss and deduction.

A successful IRS challenge to these methods or allocations could adversely affect the amount, character and timing of taxable income or loss being allocated to our unitholders. It also could affect the amount of 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 the unitholder's 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.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after December 31, 2017, it may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us, in which case our cash available for distribution to our unitholders could be substantially reduced.

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Pursuant to the Bipartisan Budget Act of 2015, for tax years beginning after December 31, 2017, if the IRS makes audit adjustments to our income tax returns, it may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us. Generally, we expect to elect to have our general partner and our unitholders take such audit adjustment into account in accordance with their interests in us during the tax year under audit, but there can be no assurance that such election will be effective in all circumstances. If we are unable to have our general partner and our unitholders take such audit adjustment into account in accordance with their interests in us during the tax year under audit, our current unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such unitholders did not own our units during the tax year under audit. If, as a result of any such audit adjustment, we are required to make payments of taxes, penalties and interest, our cash available for distribution to our unitholders could be substantially reduced. These rules are not applicable to us for tax years beginning on or prior to December 31, 2017.

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. Some of the states in which we conduct business 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 1B. Unresolved Staff Comments.

Not applicable.

Item 2. Properties.

We currently have five gathering systems which provide gathering, treating and processing services. They are (i) Mountaineer Midstream located in Doddridge and Harrison counties, West Virginia, (ii) Bison Midstream located in Mountrail and Burke counties, North Dakota, (iii) Polar and Divide primarily located in Williams and Divide counties, North Dakota, (iv) DFW Midstream primarily located in Tarrant County, Texas and (v) Grand River primarily located in Garfield, Mesa and Rio Blanco counties, Colorado and Uintah and Grand counties, Utah. For additional information on our midstream assets 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. 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 The Woodlands, Texas, and we have additional regional corporate offices in Denver, Colorado and Atlanta, Georgia.

Item 3. Legal Proceedings.

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, we are not currently a party to any significant legal or governmental proceedings. In addition,

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we are not aware of any significant legal or governmental proceedings contemplated to be brought against us, under the various environmental protection statutes to which we are subject, except as noted below.

In each of January and June 2015, the U.S. Department of Justice issued a grand jury subpoena to Summit Investments, the Partnership and our general partner requesting certain materials related to an incident involving a produced water disposal pipeline owned by Meadowlark Midstream that resulted in a discharge of materials into the environment. On February 25, 2016, the Partnership agreed to acquire, among other things, substantially all of the issued and outstanding membership interests of Meadowlark Midstream from an indirect, wholly owned subsidiary of Summit Investments in connection with the 2016 Drop Down. The 2016 Drop Down is expected to close in March 2016. See "Overview—Recent Developments—Drop Down Assets Contribution Agreement" in Item 1. Business for additional information regarding this transaction. While we cannot predict the ultimate outcome of this matter with certainty, we believe at this time that it is not likely that the Partnership or our general partner will be subject to any material liability as a result of any governmental proceeding related to the incident. The Contribution Agreement executed in connection with the 2016 Drop Down contains customary representations and warranties, and Summit Investments has agreed to indemnify the Partnership with respect to certain losses resulting from the breach of such representations and warranties.

Item 4. Mine Safety Disclosures.

Not applicable.

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PART II

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

Our limited partner common units, ticker symbol "SMLP," trade on the New York Stock Exchange. As of February 16, 2016, there were approximately 8,375 common unitholders, including beneficial owners of common units held in street name.

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

	Common unit price range		Cash distribution paid per common unit
	High	Low	
4th Quarter 2015	$21.18	$12.82	$0.575
3rd Quarter 2015	$33.74	$14.60	$0.570
2nd Quarter 2015	$36.82	$30.05	$0.565
1st Quarter 2015	$41.17	$30.31	$0.560
4th Quarter 2014	$51.44	$32.30	$0.540
3rd Quarter 2014	$56.49	$46.50	$0.520
2nd Quarter 2014	$51.25	$40.53	$0.500
1st Quarter 2014	$43.98	$34.72	$0.480

On January 21, 2016, the board of directors of our general partner declared a distribution of $0.575 per unit for the quarterly period ended December 31, 2015. The distribution, which totaled $41.0 million, was paid on February 12, 2016 to unitholders of record at the close of business on February 5, 2016.

Our Cash Distribution Policy and Restrictions on Distributions

General

Our Cash Distribution Policy. Our partnership agreement requires us to distribute all of our available cash quarterly. Our policy is to distribute to our unitholders an amount of cash each quarter that is equal to or greater than the minimum quarterly distribution stated in our partnership agreement. Generally, our available cash is our (i) cash on hand at the end of a quarter after the payment of our expenses and the establishment of cash reserves and (ii) cash on hand resulting from working capital borrowings made after the end of the quarter. Because we are not subject to an entity-level federal income tax, we have more cash to distribute to our unitholders than would be the case were we subject to federal income tax. For additional information, see Note 10 to the consolidated financial statements.

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

- Our cash distribution policy is subject to restrictions on distributions under our amended and restated revolving credit facility. Our amended and restated revolving credit facility contains financial tests and covenants that we must satisfy. Should we be unable to satisfy these restrictions, we may be prohibited from making cash distributions notwithstanding our stated cash distribution policy.
- Our general partner has the authority to establish cash reserves for the prudent conduct of our business and for future cash distributions to our unitholders, and the establishment or increase of those cash reserves could result in a reduction in cash distributions to you from the levels we currently anticipate pursuant to our stated distribution policy. Any determination to establish cash reserves made by our general partner in good faith will be binding on our unitholders.

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- Although our partnership agreement requires us to distribute all of our available cash, our partnership agreement, including the provisions requiring us to distribute all of our available cash, may be amended. Following the subordination period, which ended on February 16, 2016, we can amend our partnership agreement with the consent of our general partner and the approval of a majority of the outstanding common units (including common units beneficially owned by Summit Investments). As of December 31, 2015, Summit Investments, which is the ultimate owner of our general partner, beneficially owned 5,444,731 common units and all of our 24,409,850 subordinated units, which converted to common units on a one-for-one basis on February 16, 2016. In addition, in connection with the Purchase Program, a subsidiary of Energy Capital Partners owned 2,184,186 common units as of February 16, 2016.
- Even if our cash distribution policy is not modified or revoked, the amount of distributions we pay under our cash distribution policy and the decision to make any distribution is determined by our general partner, taking into consideration the terms of our partnership agreement.
- Under Delaware law, we may not make a distribution if the distribution would cause our liabilities to exceed the fair value of our assets.
- We may lack sufficient cash to pay distributions to our unitholders due to cash flow shortfalls attributable to a number of operational, commercial or other factors as well as increases in our operating or general and administrative expenses, principal and interest payments on our debt, tax expenses, working capital requirements and anticipated cash needs. Our cash available for distribution to unitholders is directly impacted by our cash expenses necessary to run our business and will be reduced dollar-for-dollar to the extent such uses of cash increase.
- If and to the extent our cash available for distribution materially declines, we may elect to reduce our quarterly distribution rate to service or repay our debt or fund expansion capital expenditures.

Our Minimum Quarterly Distribution

Our partnership agreement has established an MQD of $0.40 per unit per quarter, or $1.60 per unit per year, to be paid no later than 45 days after the end of each fiscal quarter. Based on all of the units outstanding as of December 31, 2015, our aggregate quarterly MQD is $27.1 million and our aggregate annual MQD is $108.5 million.

We pay our distributions on or about the 15th of each of February, May, August and November to holders of record on or about seven days prior to such distribution date. We make the distribution on the business day immediately preceding the indicated distribution date if the distribution date falls on a holiday or non-business day.

Our general partner is entitled to 2.0% of all distributions that we make prior to our liquidation. In the future, our general partner's 2.0% interest in these distributions may be reduced if we issue additional units and our general partner does not contribute a proportionate amount of capital to us to maintain its 2.0% general partner interest.

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Stock Performance Table

The following graph compares the cumulative total unitholder return on our common units since the IPO to the cumulative total return of the S&P 500 Stock Index and the Alerian MLP Index ("AMZX") by assuming $100 was invested in each investment option as of September 28, 2012, the date of the IPO. The Alerian MLP Index is a composite of the 50 most prominent energy master limited partnerships, or MLPs, and is calculated using a float-adjusted, capitalization-weighted methodology.

Issuer Purchases of Equity Securities

We made no repurchases of our common units during the quarter ended December 31, 2015.

Sponsor Purchases of Equity Securities

The table below presents common units which our Sponsor acquired through its affiliates, including Summit Investments, via open market transactions during the three months ended December 31, 2015.

	(a) Total Number of Common Units Purchased	(b) Average Price Paid Per Common Unit	(c) Total Number of Common Units Purchased as Part of Publicly Announced Plans or Programs (1)	(d) Maximum Number (or Approximate Dollar Value) of Common Units That May Yet Be Purchased Under the Plans or Programs (1)
October 1 - 31, 2015	—	$—	—	$—
November 1 - 30, 2015	—	$—	—	$—
December 1 - 31, 2015	296,114	$17.25	296,114	$94,886,798

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(1) In December 2015, Energy Capital Partners approved the Purchase Program.

Equity Compensation Plans

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

Item 6. Selected Financial Data.

The selected consolidated financial data presented as of and for the years ended December 31, 2015, 2014, 2013, 2012, and 2011 have been derived from the consolidated financial statements of SMLP and its Predecessor.

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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.

These financial statements reflect the results of operations of (i) Bison Midstream and Polar and Divide since February 16, 2013, (ii) Mountaineer Midstream since June 22, 2013, (iii) Red Rock Gathering since October 23, 2012 and (iv) Legacy Grand River since October 27, 2011. SMLP recognized its acquisitions of Polar and Divide (the "Polar and Divide Drop Down"), 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 over the purchase price paid for a contributed subsidiary is recognized as an addition to partners' capital, while the excess of purchase price paid over net investment is recognized as a reduction to partners' capital. Due to the common control aspect, we account for drop downs on an “as-if pooled” basis for the periods during which common control existed.

Due to the various asset acquisitions and the associated shift in business strategies relative to those of our 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.

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

	December 31,				
	2015	2014	2013	2012	2011
	(In thousands, except per-unit amounts)				
Balance sheet data:					
Total assets	$2,040,531	$2,293,721	$2,191,143	$1,280,939	$1,030,264
Total long-term debt	944,000	808,000	586,000	199,230	349,893
Partners' capital	984,242	1,351,721	1,493,087	1,030,248	n/a
Membership interests	n/a	n/a	n/a	n/a	640,818
Other data:					
Market price per common unit	$18.73	$38.00	$36.65	$19.83	n/a

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n/a - Not applicable

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

	Year ended December 31,				
	2015	2014	2013	2012	2011
	(In thousands, except per-unit amounts)				
Statement of operations data:					
Total revenues	$371,319	$372,703	$323,686	$174,423	$103,552
Total costs and expenses (1)	510,190	347,836	250,952	117,987	61,864
Interest expense	48,616	40,159	19,173	7,340	1,029
Affiliated interest expense	—	—	—	5,426	2,025
Net (loss) income	(186,809)	(14,734)	52,837	42,997	37,951
(Loss) earnings per limited partner unit:					
Common unit – basic	$(3.20)	$(0.49)	$0.86	$0.35	n/a
Common unit – diluted	(3.20)	(0.49)	0.86	0.35	n/a
Subordinated unit – basic and diluted	(2.88)	(0.44)	0.79	0.35	n/a
Other financial data:					
EBITDA (1)	$(41,896)	$114,345	$144,340	$93,302	$53,363
Adjusted EBITDA	210,445	204,907	165,324	105,946	56,803
Capital expenditures	118,107	220,820	182,978	77,296	78,248
Acquisition capital expenditures (2)	288,618	315,872	458,914	—	589,462
Distributable cash flow	153,373	150,318	128,457	90,947	50,980
Distributions declared per unit (3)	2.285	2.120	1.795	0.410	n/a

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n/a - Not applicable

(1) Includes goodwill impairments of $248.9 million in 2015 and $54.2 million in 2014. See Note 6 to the consolidated financial statements.

(2) Reflects consideration paid, including working capital and capital expenditure adjustments paid (received), to fund acquisitions and/or drop downs.

(3) Represents distributions declared in respect of a given period. For example, for the year ended December 31, 2015, represents the distributions declared in April 2015 for the first quarter of 2015, July 2015 for the second quarter of 2015, October 2015 for the third quarter of 2015 and January 2016 for the fourth quarter of 2015.

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 consolidated financial statements and notes thereto.

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

MD&A is intended to inform the reader about matters affecting the financial condition and results of operations of SMLP and its subsidiaries. As a result, the following discussion should be read in conjunction with the consolidated financial statements and notes thereto included in this report. Among other things, those consolidated 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. Actual results may differ materially from those contained in any forward-looking statements.

This MD&A comprises the following sections:

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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 the continental United States. We conduct and report our operations in the midstream energy industry through four reportable segments:

- the Marcellus Shale, which is served by Mountaineer Midstream;
- the Williston Basin, which is served by Bison Midstream and Polar and Divide;
- the Barnett Shale, which is served by DFW Midstream; and
- the Piceance Basin, which is served by Grand River.

Our results are driven primarily by the volumes that we gather, treat and/or process. We generate the majority of our revenue from the natural gas gathering, treating and processing services that we provide to our natural gas customers. Under the substantial majority of these agreements, we are paid a fixed fee based on the volumes we gather, treat and/or process. These agreements enhance the stability of our cash flows by providing a revenue stream that is not subject to direct commodity price risk.

We also earn revenue from (i) crude oil and produced water gathering, (ii) the sale of physical natural gas and natural gas liquids ("NGLs") purchased under percentage-of-proceeds arrangements with certain of our customers on the Bison Midstream and Grand River gathering systems, (ii) the sale of natural gas we retain from our DFW Midstream customers and (iii) the sale of condensate we retain from our gathering services at Grand River. We can be exposed to commodity price risk from engaging in any of these additional activities with the exception of crude oil and produced water gathering. We also have indirect exposure to changes in commodity prices in that persistent low commodity prices may cause our customers to delay or cancel drilling and/or completion activities or temporarily shut-in production, which would reduce the volumes of natural gas and crude oil (and associated volumes of produced water) that we gather. If our customers cancel or delay drilling and/or completion activities or temporarily shut-in production, our MVCs ensure that we will receive a certain amount of revenue from certain of our customers.

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The following table presents certain consolidated financial data for the years ended December 31.

	Year ended December 31, 2015	2014	2013
	(In thousands)		
Selected Financial Results:			
Net (loss) income	$(186,809)	$(14,734)	$52,837
EBITDA (1)	(41,896)	114,345	144,340
Adjusted EBITDA (1)	210,445	204,907	165,324
Distributable cash flow (1)	153,373	150,318	128,457
Acquisitions of gathering systems (2)	$288,618	$315,872	$458,914
Capital expenditures (3)	118,107	220,820	182,978
Proceeds from issuance of common units, net (4)	$221,977	$197,806	$—
Issuance of senior notes	—	300,000	300,000
Borrowings (repayments) under revolving credit facility, net	136,000	(78,000)	86,770
Distributions to unitholders	152,074	122,224	90,196

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(1) See "Non-GAAP Financial Measures" herein for additional information on EBITDA, adjusted EBITDA and distributable cash flow as well as their reconciliations to the most directly comparable GAAP financial measure.
(2) Reflects consideration paid, including working capital and capital expenditure adjustments paid (received), for acquisitions and/or drop downs. For additional information, see Note 15 to the consolidated financial statements.
(3) See "Liquidity and Capital Resources" herein for additional information on capital expenditures.
(4) Reflects proceeds from underwritten primary offerings and does not include proceeds from units issued to affiliates to affect acquisitions or drop downs.

Year ended December 31, 2015. After a slight pause mid-year 2015, commodity prices continued to decline in response to the global supply surplus. As a result, several of the producers in our areas of operations announced plans to cancel, delay and/or reduce drilling plans which in turn negatively impacted the margins that we earn, slowing the growth in net income and adjusted EBITDA. In addition to impacting the margins that we earn and net income, the goodwill that we had previously recognized in connection with our acquisitions of Polar and Divide and Grand River was determined to be fully impaired, resulting in a write-off of $248.9 million.

During 2015, we acquired Polar and Divide from a subsidiary of Summit Investments in a drop down transaction. We also began and/or completed system expansion projects on the Polar and Divide, Grand River and Bison Midstream systems.

In May 2015, we completed an underwritten primary offering of common units and used the proceeds along with borrowings under our revolving credit facility to fund the Polar and Divide Drop Down. Distributions declared in respect of the fourth quarter of 2015 increased 2.7% over distributions declared in respect of the fourth quarter of 2014.

Year ended December 31, 2014. In the second half of 2014, commodity prices began to decline, negatively impacting producers in each of our areas of operation. The impact of these declines were most evident in our North Dakota operations where our percentage of fee-based gathering agreements is less than that of our other systems. In addition to impacting the margins that we earned, the goodwill that we had previously recognized in connection with our acquisition of Bison Midstream was determined to be fully impaired, resulting in a write-off of $54.2 million.

During 2014, we acquired Red Rock Gathering from a subsidiary of Summit Investments in a drop down transaction. We also completed several system expansion projects across all systems.

In March 2014, we completed an underwritten public offering of primary and secondary units and we also completed a secondary offering in September 2014. We used the funds from the March 2014 primary offering to partially fund the Red Rock Drop Down. In July 2014, we also issued senior notes and used the proceeds to repay a portion of our outstanding revolving credit facility balance. Distributions declared in respect of the fourth quarter of 2014 increased

16.7% over distributions declared in respect of the fourth quarter of 2013.

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Year ended December 31, 2013. During 2013, we acquired Bison Midstream from a subsidiary of Summit Investments in a drop down transaction and Mountaineer Midstream in a third-party acquisition. We also completed several system expansion projects across all systems.

In June 2013, we issued senior notes and common units to Summit Investments to fund the acquisitions of Bison Midstream and Mountaineer Midstream. Distributions declared in respect of the fourth quarter of 2013 increased 17.1% over distributions declared in respect of the fourth quarter of 2012.

For additional information, see Item 1. Business, the remainder of this MD&A and the notes to the consolidated financial statements included herein.

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, NGL and crude oil supply and demand dynamics;
- Growth in production from U.S. shale plays;
- Capital markets activity and cost of capital;
- Acquisitions from third parties; and
- Shifts in 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, NGL and crude oil supply and demand dynamics. Natural gas continues to be a critical component of energy supply and demand in the United States. The price of natural gas has decreased, with the New York Mercantile Exchange, or NYMEX, natural gas futures price at $2.28 per MMBtu as of December 31, 2015 compared with $2.89 per MMBtu as of December 31, 2014 and $4.23 per MMBtu as of December 31, 2013. Natural gas prices continue to trade at lower-than-average historical prices due in part to increased production, especially from unconventional sources, such as natural gas shale plays. According to the U.S. Energy Information Administration (the "EIA"), average annual natural gas production in the United States increased to 85.9 Bcf/d, or 55.9%, in 2014 from 55.1 Bcf/d in 2008. Over the same time period, natural gas consumption increased only 15.0% to 73.1 Bcf/d. In response to lower natural gas prices, the number of active natural gas drilling rigs has declined from approximately 1,350 in December 2008 to approximately 162 in December 2015, according to Baker Hughes.

Lower natural gas prices in 2015 relative to 2014 and 2013 are also attributable to U.S. weather patterns that contributed to temperatures that were 24% warmer than historical norms in the second half of 2015, which resulted in lower-than-normal overall consumption of natural gas. As a result, the amount of natural gas in storage in the continental United States increased to approximately 3.8 Tcf as of December 25, 2015, compared with approximately 3.2 Tcf as of December 26, 2014, and a five-year historical December average of 3.5 Tcf. Additionally, a number of exploration and production companies made public announcements in 2015 regarding abnormally high production rates from natural gas wells targeting the Utica Shale formation in Ohio, West Virginia and Pennsylvania, which has resulted in a recalibration of the market’s expectation for future natural gas supplies in the United States.

We believe that over the near term, until the supply of natural gas has been reduced, weather patterns change, resulting in colder temperatures, or the broader economy experiences more robust growth to stimulate higher demand, 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 primarily by population and economic growth, as well as the continued displacement of coal-fired electricity generation by natural gas-fired electricity generation. For example, according to the EIA, coal-fired power plants generated 39% of the electricity in the United States in 2014, compared with 48% in 2008. The EIA expects this trend to continue, with coal-fired power plants representing 34% of total electricity generation by 2040.

In April 2015, the EIA projected total annual domestic consumption of natural gas to increase from approximately 71.8 Bcf/d in 2013 to approximately 81.4 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 97.3 Bcf/d. The EIA also projects that the United States will be a net exporter of liquefied natural gas, or LNG, by 2017, with net U.S. exports of LNG projected to rise to 15.3 Bcf/d in 2040, compared with net imports of 4.1 Bcf/d in 2013. 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, the Bison Midstream and Polar and Divide systems are directly affected by crude oil supply and demand dynamics. Crude oil has been the focus of a recent global supply surplus, with OPEC initially stating in November 2014 and throughout 2015 that it would not decrease production levels, despite concerns of slowing global demand, particularly in historically high growth countries such as China. This, in conjunction with continued crude oil production growth from unconventional shale plays in the United States, and expected crude oil production growth in countries that have had limited production outputs of late, such as Iran, has played a significant role in the recent decline in crude oil prices, with NYMEX crude oil futures ending 2015 at $37.13 per barrel, compared to a high in June 2014 of $107.26 per barrel. In response to lower crude oil prices, the number of active crude oil drilling rigs has declined from a peak of 1,609 in October 2014 to 536 in December 2015, according to Baker Hughes. For additional information, see the "Critical Accounting Estimates—Recognition and Impairment of Long-Lived Assets" section herein and Notes 4, 5 and 6 to the consolidated financial statements.

Over the next several years, the EIA projects that domestic crude oil production will continue to increase from an average of 8.7 million Bbl/d in 2014 to 10.6 million Bbl/d in 2020. While long-term estimates vary due to uncertainty regarding long-term crude oil price trends, the EIA still sees continued growth in certain unconventional shale plays, with crude oil prices expected to remain high enough to support continued drilling and increasing production in the Bakken Shale, Eagle Ford Shale, Permian Basin, and Niobrara Shale. Additionally, in December 2015, the United States lifted a ban that had previously prohibited crude oil exports. This repeal should, over time, enable the West Texas Intermediate ("WTI") crude oil price benchmark to become more competitive with other global crude oil price benchmarks, thus stimulating incremental domestic 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 shale resources. While the EIA expects total dry natural gas production to grow 38.1% from 25.7 Tcf in 2014 to 35.5 Tcf in 2040, it expects shale gas production to grow to 19.6 Tcf in 2040, representing 55% of total U.S. natural 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, producers have leased large acreage positions in the areas in which we operate and other unconventional resource plays. To help fund their drilling programs in many of these areas, a number of producers have 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 support sustained drilling activity.

As a result of the current low commodity price environment, many producers have announced reductions to their capital expenditure budgets by limiting their drilling activities in lower performing resource plays or in lower tier areas within higher performing resource plays. In addition, the low commodity price environment has left a number of producers in financial distress, evidenced in part by the 31 U.S.-based exploration and production companies that filed for bankruptcy protection in 2015. Nevertheless, we believe producers will remain focused on deploying capital in their highest quality resource plays, even in a low commodity price environment.

Capital markets activity and cost of capital. After multiple years of near-record low interest rates, the credit markets reversed in 2015 and borrowing costs increased for virtually all crude oil and natural gas industry-related borrowers. Additionally, in December 2015, the Federal Reserve announced that it would raise its benchmark federal-funds rate from near zero to a range between 0.25% and 0.50%, the first such increase since 2006. The Federal Reserve also announced its intent to continue to raise interest rates gradually in the future, to the extent that economic growth continues. Capital markets conditions, including but not limited to higher borrowing costs, could affect our ability to access the debt capital markets to the extent necessary to fund our future 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 debt capital on acceptable terms, we expect to remain

competitive with respect to acquisitions and capital projects, as our competitors would face similar circumstances.
Acquisitions from Third Parties. Our principal business strategy is to increase the amount of cash distributions we make to our unitholders over time. Our ability to grow cash distributions depends, in part, on our ability to make acquisitions that increase the amount of cash generated from our operations on a per-unit basis, along with other factors. Following the 2016 Drop Down, we intend to continue to pursue accretive acquisitions of midstream assets

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from third parties. However, their size, timing and/or contribution to our results of operations cannot be reasonably estimated. Furthermore, there are a number of risks and uncertainties that could cause our current expectations to change, including, but not limited to, (i) the ability to reach agreement on acceptable terms with third parties; (ii) prevailing conditions and outlook in the natural gas, crude oil and natural gas liquids industries and markets and (iii) our ability to obtain financing on acceptable terms from commercial banks, the capital markets or other sources.

The acquisition component of our principal business strategy has required and will continue to require significant expenditures by us as well as access to external sources of financing from the debt and equity capital markets. Furthermore, as our Sponsor and Summit Investments are under no obligation to provide any direct or indirect financial assistance to us, we rely primarily on external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund our acquisitions and expansion capital expenditures. Any prospective third-party transaction would be impacted by our ability to obtain financing on acceptable terms from the capital markets or other sources, among other factors.

We expect to finance potential third-party acquisitions with equity offerings and borrowings under our revolving credit facility, initially. Longer-term financing is expected to be provided by the issuance of additional debt and equity securities. See the "Liquidity and Capital Resources—Capital Requirements" section herein and Notes 8 and 10 to the consolidated financial statements for additional information.

Shifts in operating costs and inflation. Throughout most of the last five years, high levels of crude oil and natural gas exploration, development and production activities across the United States resulted in increased competition for personnel and equipment as well as higher prices for labor, supplies, equipment and other services. Beginning in 2015, this dynamic began to shift as prices for crude oil and natural gas-related services decreased as overall demand for these goods and services declined. While we expect lower service-related costs in the near term, we expect that over the longer term, these costs will continue to have a high correlation the prevailing price of crude oil and natural gas.

How We Evaluate Our Operations

We conduct and report our operations in the midstream energy industry through four reportable segments:

- the Marcellus Shale;
- the Williston Basin;
- the Barnett Shale; and
- the Piceance Basin.

Each of our reportable segments provides midstream services in a specific geographic area. Our reportable segments reflect the way in which we internally report the financial information used to make decisions and allocate resources in connection with our operations. See Note 3 to the consolidated financial statements for additional information.

Our management uses a variety of financial and operational metrics to analyze our consolidated and segment performance. We view these metrics as important factors in evaluating our profitability and determining the amounts of cash distributions to pay to our unitholders. These metrics include:

- throughput volume,
- revenues,
- operation and maintenance expenses,
- EBITDA,
- adjusted EBITDA and segment adjusted EBITDA, and
- distributable cash flow.

Throughput Volume

The volume of (i) natural gas that we gather, treat and/or process and (ii) crude oil and produced water that we gather 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. Furthermore,

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because the production rate of natural gas and crude oil wells decline over time, production can only be maintained or increased by new drilling or other activity.

As a result, we must continually obtain new supplies of production 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 throughput is impacted by:

- successful drilling activity within our AMIs;
- 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 AMIs awaiting connections;
- our ability to compete for volumes from successful new wells in the areas in which we operate outside of our existing AMIs; and
- our ability to gather, treat and/or process production that has been released from commitments with our competitors.

We report volumes gathered for natural gas in cubic feet; natural gas gathering rates are reported in millions of cubic feet per day ("MMcf/d"). We aggregate crude oil and produced water gathering and report it in barrels; liquids gathering rates are reported in thousands of barrels per day ("Mbbl/d").

Revenues

Our revenues are primarily attributable to the volumes that we gather, treat and/or process and the rates we charge for those services. A substantial majority of our gathering and processing agreements are fee-based, which limits our direct commodity price exposure. We also have percent-of-proceeds arrangements under which the gathering and processing revenues that we earn correlate directly with the fluctuating price of natural gas, condensate and NGLs. We report throughput rates for natural gas on a per thousand cubic feet ("Mcf") basis and throughput rates for liquids on a per barrel ("Bbl") basis.

Many of our gathering and processing agreements contain MVCs pursuant to which our customers agree to ship or process a minimum volume of production on our gathering systems, or, in some cases, to pay a minimum monetary amount, over certain periods during the term of the MVC. These MVCs support our revenues and serve to mitigate the financial impact associated with declining volumes.

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, ad valorem 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 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. 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, Segment Adjusted EBITDA and Distributable Cash Flow

EBITDA, adjusted EBITDA, segment 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 (including segment adjusted EBITDA) are used to assess:

- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;

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- 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 (including segment 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 gathering agreements or the timing of impairments or other noncash income or expense items.

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.

Items Affecting the Comparability of Our Financial Results

Our historical results of operations may not be comparable to our future results of operations for the reasons described below:

- The consolidated financial statements reflect the results of operations of Bison Midstream and Polar and Divide since February 16, 2013. We accounted for the drop down of these assets on an "as-if pooled" basis because the transactions were executed by entities under common control. The Polar and Divide system commenced operations in May 2013.
- The consolidated financial statements reflect the results of operations of Mountaineer Midstream since June 22, 2013.

For additional information, see the "Results of Operations" and "Non-GAAP Financial Measures" sections herein and the notes to the consolidated financial statements. For information on impending accounting changes that are expected to materially impact our financial results reported in future periods, see Note 2 to the consolidated financial statements.

Results of Operations

Our financial results are recognized as follows:

Gathering services and related fees. Revenue earned from the gathering, treating and processing services that we provide to our natural gas and crude oil producer customers.

Natural gas, NGLs and condensate sales. Revenue earned from (i) the sale of physical natural gas and natural gas liquids purchased under percentage-of-proceeds arrangements with certain of our customers on the Bison Midstream and Grand River gathering systems, (ii) the sale of natural gas we retain from our DFW Midstream customers and (iii) the sale of condensate we retain from our gathering services at Grand River.

Other revenues. Revenue earned primarily from (i) certain costs for which our Bison Midstream and Grand River customers have agreed to reimburse us and (ii) connection fees for customers of the Polar and Divide system.

Cost of natural gas and NGLs. The cost of natural gas and NGLs represents the costs associated with the percent-of-proceeds arrangements under which we sell natural gas purchased from certain of our customers on the Bison Midstream and Grand River gathering systems.

Operation and maintenance. Operation and maintenance primarily comprises direct labor costs, compression costs, ad valorem taxes, repair and non-capitalized maintenance costs, integrity management costs, utilities and contract services. These items represent the most significant portion of our operation and maintenance expense. Other than utilities expense, these expenses are largely independent of variations in throughput volumes but may fluctuate depending on the activities performed during a specific period. Operation and maintenance also includes our procurement of electricity to operate our electric-drive compression assets on the DFW Midstream system.

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General and administrative. Expenses associated with our operations that are not specifically associated with the operation and maintenance of a particular system or another cost and expense line item. These expenses largely reflect salaries, benefits and incentive compensation, professional fees, insurance and rent.
Transaction costs. Financial and legal advisory costs associated with completed acquisitions.
Depreciation and amortization. The amortization of our contract and right-of-way intangible assets and the depreciation of our property, plant and equipment.
Other income or expense. Generally represents interest income but may also include other items of gain or loss.
Interest expense. Interest expense associated with our revolving credit facility and senior notes.
Income tax expense. Since we are structured as a partnership, we are generally not subject to federal and state income taxes, except the Texas Margin Tax, which is reflected herein.
Consolidated Overview of the Years Ended December 31, 2015, 2014 and 2013
The following table presents certain consolidated and operating data for the years ended December 31.

	Year ended December 31,			Percentage Change	
	2015	2014	2013	2015 v. 2014	2014 v. 2013
	(Dollars in thousands, except fee-rate data)				
Revenues:					
Gathering services and related fees	$310,829	$255,211	$213,979	22 %	19 %
Natural gas, NGLs and condensate sales	42,079	97,094	88,185	(57)%	10 %
Other revenues	18,411	20,398	21,522	(10)%	(5)%
Total revenues	371,319	372,703	323,686	— %	15 %
Costs and expenses:					
Cost of natural gas and NGLs	31,398	72,415	68,037	(57)%	6 %
Operation and maintenance	87,285	88,927	77,114	(2)%	15 %
General and administrative	36,544	38,269	32,273	(5)%	19 %
Transaction costs	790	730	2,841	8 %	(74)%
Depreciation and amortization	96,189	87,349	70,574	10 %	24 %
(Gain) loss on asset sales, net	(172)	442	113	*	*
Long-lived asset impairment	9,305	5,505	—	*	*
Goodwill impairment	248,851	54,199	—	*	*
Total costs and expenses	510,190	347,836	250,952	47 %	39 %
Other income	2	1,189	5	*	*
Interest expense	(48,616)	(40,159)	(19,173)	21 %	109 %
(Loss) income before income taxes	(187,485)	(14,103)	53,566	*	*
Income tax benefit (expense)	676	(631)	(729)	*	(13)%
Net (loss) income	$(186,809)	$(14,734)	$52,837	*	*
Operating Data:					
Aggregate average throughput – gas (MMcf/d)	1,449	1,418	1,138	2 %	25 %
Aggregate average throughput rate per Mcf – gas	$0.46	$0.46	$0.50	— %	(8)%
Average throughput – liquids (Mbbl/d)	55.0	33.6	10.9	64 %	*
Average throughput rate per Bbl – liquids	$1.84	$1.64	$0.95	12 %	73 %

* Not considered meaningful

Volumes – Gas. For the year ended December 31, 2015, our aggregate natural gas throughput volumes increased primarily reflecting an increase in volume throughput for Mountaineer Midstream, partially offset by volume throughput declines on Grand River.

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For the year ended December 31, 2014, our aggregate natural gas throughput volumes increased largely reflecting the contribution from Mountaineer Midstream and Grand River. These production increases were partially offset by volume throughput declines on the DFW Midstream and Legacy Grand River systems.

Volumes – Liquids. Average daily throughput for crude oil and produced water increased during the years ended December 31, 2015 and 2014, primarily reflecting the continued development of the Polar and Divide system, new pad site connections and producers' ongoing drilling activity.

Revenues. For the year ended December 31, 2015, total revenues decreased $1.4 million primarily reflecting:

- the recognition in 2015 of previously deferred revenue at Grand River (see Note 7 to the consolidated financial statements).
- an increase in gathering services and related fees for the Polar and Divide and Mountaineer Midstream systems.
- an offset to revenues as a result of declines in natural gas, NGLs and condensate sales for Bison Midstream, Grand River and DFW Midstream.

For the year ended December 31, 2014, total revenues increased $49.0 million, or 15%, primarily reflecting:

- overall growth at Red Rock Gathering and Polar and Divide.
- an increase in gathering services and related fees at Mountaineer Midstream due in large part to the partial year of ownership in 2013.
- overall growth at Bison Midstream primarily due to higher volume throughput.
- an overall decline in DFW Midstream revenues largely due to lower volume throughput.

Gathering Services and Related Fees. The increase in gathering services and related fees during the year ended December 31, 2015 was primarily driven by the recognition of previously deferred revenue noted above and higher volume throughput on the Polar and Divide and Mountaineer Midstream systems.

The aggregate average throughput rate for natural gas decreased to $0.46/Mcf during the year ended December 31, 2015, compared with $0.46/Mcf in the prior-year period primarily as a result of a larger proportion of gathering fee revenue from Mountaineer Midstream. The aggregate average throughput rate for crude oil and produced water increased to $1.84/Bbl during the year ended December 31, 2015, compared with $1.64/Bbl in the prior-year period primarily as a result of the effect of contract amendments in 2014 which increased gathering rates in connection with our commitment to further expand the Polar and Divide system.

For the year ended December 31, 2014, gathering services and related fees increased primarily reflecting the proportionate contribution of higher margin volume throughput from certain customers and the first quarter 2014 commissioning of a natural gas processing plant at Grand River; the impact of higher volume throughput on gathering services and related fees and higher gathering rates associated with contract amendments in 2014 for Polar and Divide; and a full year of operations under SMLP's management as well as our build out of the Mountaineer Midstream system. These increases were partially offset by the continued natural decline in volumes and lack of producer drilling activity on the DFW Midstream system.

The aggregate average throughput rate for natural gas decreased to $0.46/Mcf during the year ended December 31, 2014, compared with $0.50/Mcf in the prior-year period largely as a result of a larger proportion of gathering fee revenue from Mountaineer Midstream, partially offset by an increase for Grand River due to a shift in volume mix. The aggregate average throughput rate for crude oil and produced water increased to $1.64/Bbl during the year ended December 31, 2014, compared with $0.95/Bbl in the prior-year period primarily as a result of the effect of 2014 contract amendments noted above.

Natural Gas, NGLs and Condensate Sales. The decrease in natural gas, NGLs and condensate sales for the years ended December 31, 2015 and 2014 was primarily a result of the impact of declining commodity prices. Declining commodity prices negatively impacted our percent-of-proceeds arrangements at Bison Midstream and Grand River, our fuel retainage revenue at DFW Midstream and condensate revenue for Grand River.

Costs and Expenses. Total costs and expenses increased $162.4 million, or 47%, for the year ended December 31, 2015 primarily reflecting:

- the goodwill impairments recognized for Polar and Divide and Grand River.
- a partial offset resulting from lower cost of natural gas and NGLs at Bison Midstream and Grand River.

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- an increase in depreciation and amortization expense for all systems, except DFW Midstream.
- a partial offset due to the impact of the 2014 goodwill and long-lived asset impairments.

For the year ended December 31, 2014, total costs and expenses increased $96.9 million, or 39%, primarily reflecting:

- the goodwill impairment recognized for Bison Midstream.
- an increase in depreciation and amortization across our gathering systems.
- an increase in cost of natural gas and NGLs for Bison Midstream and Grand River.
- an increase in operation and maintenance expense as a result of the continued development of the Polar and Divide system.

Cost of Natural Gas and NGLs. The decrease in cost of natural gas and NGLs for the year ended December 31, 2015 was largely driven by declining commodity prices and the associated impact on our percent-of-proceeds arrangements at Bison Midstream and Grand River. The increase in cost of natural gas and NGLs for the year ended December 31, 2014 was primarily attributable to an increase in volume throughput, partially offset by declining commodity prices.

Operation and Maintenance. Operation and maintenance expense decreased during the year ended December 31, 2015 primarily reflecting a decline in electricity expense associated with DFW Midstream's electric-drive compression assets and a decline in pass-through electricity expense for Grand River (revenue component is recognized in other revenues.) These decreases were partially offset by an increase in connection fee pass-through expense for Polar and Divide as a result of system expansion (revenue component is recognized in other revenues), an increase in property taxes and an increase in compensation expense.

Operation and maintenance expense increased during the year ended December 31, 2014 primarily as a result of a full year of operations for both Mountaineer Midstream and Polar and Divide as well as higher expenses at Bison Midstream, including an increase in pass-through electricity expense (revenue component is recognized in other revenues).

General and Administrative. General and administrative expense decreased during the year ended December 31, 2015 reflecting a decline in professional services, primarily the result of expenses incurred in 2014 in connection with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002 and our adoption of Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO 2013"). Expenses for salaries and benefits also declined due to a reduction in incentive compensation. These decreases were partially offset by increases in unit-based compensation and rent expenses.

General and administrative expense increased during the year ended December 31, 2014, largely as a result of an increase in salaries, benefits and incentive compensation primarily due to increased head count, an increase in professional expenses associated with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002 and our adoption of COSO 2013.

Transaction Costs. Transaction costs recognized primarily relate to financial and legal advisory costs associated with the Polar and Divide Drop Down in 2015, the Red Rock Drop Down in 2014 and the Bison Drop Down and the acquisition of Mountaineer Midstream in 2013.

Depreciation and Amortization. The increase in depreciation and amortization expense during the years ended December 31, 2015 and 2014 was largely driven by an increase in assets placed into service and an increase in contract amortization largely due to Grand River.

Interest Expense. The increase in interest expense during the year ended December 31, 2015 was primarily driven by our July 2014 issuance of 5.5% senior notes.

The increase in interest expense during the year ended December 31, 2014 was primarily driven by our June 2013 issuance of 7.5% senior notes.

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Segment Overview of the Years Ended December 31, 2015, 2014 and 2013

Marcellus Shale. Mountaineer Midstream, a natural gas gathering system, provides our midstream services for the Marcellus Shale reportable segment. We acquired Mountaineer Midstream in June 2013. Volume throughput for the Marcellus Shale reportable segment follows.

	Marcellus Shale (1)					
	Year ended December 31,			Percentage Change		
	2015	2014	2013 (2)	2015 v. 2014		2014 v. 2013
Operating Data:						
Average throughput (MMcf/d)	478	382	87	25	%	*

* Not considered meaningful
(1) Contract terms related to throughput rate per MCF are excluded for confidentiality purposes.
(2) For the period of SMLP's ownership in 2013, average throughput was 164 MMcf/d.

The increase in volume throughput in 2015, compared to 2014, was primarily driven by the upstream connection of wells owned by Mountaineer Midstream's anchor customer, Antero.

The increase in volume throughput in 2014, compared with 2013, reflects the continuation of active drilling by Antero and the connection of new wells upstream of the Mountaineer Midstream system as well as the impact of new, upstream compressor stations commissioned by third parties, which contributed to volume throughput.

We expect volumes on the Mountaineer Midstream system to increase throughout the second and third quarters of 2016 as Antero completes a portion of its deferred well inventory.

Financial data for our Marcellus Shale reportable segment follows.

	Marcellus Shale						
	Year ended December 31,			Percentage Change			
	2015	2014	2013	2015 v. 2014		2014 v. 2013	
	(In thousands)						
Revenues:							
Gathering services and related fees	$28,468	$22,694	$9,588	25	%	137	%
Total revenues	28,468	22,694	9,588	25	%	137	%
Costs and expenses:							
Operation and maintenance	4,886	4,560	2,447	7	%	86	%
General and administrative	368	2,194	808	(83	)%	*	
Depreciation and amortization	8,682	7,648	3,998	14	%	91	%
Total costs and expenses	13,936	14,402	7,253	(3	)%	99	%
Add:							
Depreciation and amortization	8,682	7,648	3,998				
Segment adjusted EBITDA	$23,214	$15,940	$6,333	46	%	*	

* Not considered meaningful

Year ended December 31, 2015. Segment adjusted EBITDA increased $7.3 million during 2015 reflecting:

- the impact of an increase in volume throughput which translated into higher gathering services and related fees revenue.
- minimum revenue commitment payments related to the Zinnia Loop project, beginning in the first quarter of 2015.
- a decline in general and administrative expenses primarily as a result of our decision to discontinue allocating certain corporate general and administrative expenses to our reportable segments beginning in the first quarter of 2015.
- an increase in operation and maintenance primarily as a result of system expansion and the associated increase in volume throughput.

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Depreciation and amortization increased during 2015 largely as a result of commissioning the Zinnia Loop project late in the third quarter of 2014.

Year ended December 31, 2014. Segment adjusted EBITDA increased $9.6 million during 2014 reflecting:

- a full year of operations under SMLP's management as well as our build out of the Mountaineer Midstream system to keep pace with increases in production from Antero as processing capacity at MPLX’s Sherwood Processing Complex increased.

Depreciation and amortization increased during the year ended December 31, 2014 largely as a result of a full year of operations.

Williston Basin. Bison Midstream and Polar and Divide provide our services for the Williston Basin reportable segment. Bison Midstream, an associated natural gas gathering system, was acquired from a subsidiary of Summit Investments in June 2013. Polar and Divide, a crude oil and produced water gathering system and transmission pipelines, was acquired from subsidiaries of Summit Investments in May 2015. Our results include activity for Bison Midstream and Polar and Divide since February 16, 2013, the date on which common control began.

Operating data for our Williston Basin reportable segment follows.

	Williston Basin						
	Year ended December 31,			Percentage Change			
	2015	2014	2013	2015 v. 2014		2014 v. 2013	
Operating Data:							
Average throughput – natural gas (MMcf/d) (1)	18	18	14	—	%	29	%
Average throughput rate per Mcf – gas	$2.53	$3.46	$3.86	(27	)%	(10	)%
Average throughput (Mbbl/d) – liquids (2)	55.0	33.6	10.9	64	%	*	
Average throughput rate per Bbl – liquids	$1.84	$1.64	$0.95	12	%	73	%

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* Not considered meaningful

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

(2) For the year ended December 31, 2013. For the period of SMLP's ownership in 2013, average throughput was 12.5 Mbbl/d.

Natural gas. Natural gas volume throughput was flat in 2015 compared with 2014 due to the offsetting effects of customers reducing their drilling activities in response to continued declines in commodity prices and increases in gas-to-oil ratios on existing production.

The increase in natural gas volume throughput in 2014 primarily reflects additional pad site connections and newly installed compression capacity, which improved system hydraulics.

The declines in natural gas gathering rates in 2015 and 2014 were primarily a result of the impact of declining commodity prices on volumes associated with a percent-of-proceeds contract.

Liquids. The increase in liquids volume throughput in 2015 and 2014 reflect new pad site connections and ongoing drilling activity in Polar and Divide's service area.

The increase in average throughput rate for liquids for 2015 and 2014 was primarily as a result of contract amendments in 2014 which increased gathering rates in connection with our commitment to further expand the Polar and Divide system.

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Financial data for our Williston Basin reportable segment follows.

	Williston Basin			Percentage Change	
	Year ended December 31,				
	2015	2014	2013	2015 v. 2014	2014 v. 2013
	(In thousands)				
Revenues:					
Gathering services and related fees	$50,233	$36,672	$21,132	37 %	74 %
Natural gas, NGLs and condensate sales	23,525	56,040	47,130	(58)%	19 %
Other revenues	12,129	11,759	13,239	3 %	(11)%
Total revenues	85,887	104,471	81,501	(18)%	28 %
Costs and expenses:					
Cost of natural gas and NGLs	23,090	54,480	54,840	(58)%	(1)%
Operation and maintenance	24,380	21,768	8,849	12 %	146 %
General and administrative	3,362	7,755	4,402	(57)%	76 %
Depreciation and amortization	26,280	22,491	16,669	17 %	35 %
(Gain) loss on asset sales, net	5	296	—	*	*
Long-lived asset impairment	7,554	—	—	*	*
Goodwill impairment	203,373	54,199	—	*	*
Total costs and expenses	288,044	160,989	84,760	79 %	90 %
Add:					
Depreciation and amortization	26,280	22,491	16,669		
Adjustments related to MVC shortfall payments	11,870	10,743	3,600		
Unit-based compensation	85	340	340		
Loss on asset sales	5	296	—		
Long-lived asset impairment	7,554	—	—		
Goodwill impairment	203,373	54,199	—		
Segment adjusted EBITDA	$47,010	$31,551	$17,350	49 %	82 %

* Not considered meaningful

Year ended December 31, 2015. Segment adjusted EBITDA increased $15.5 million during 2015 reflecting:

- the impact of higher volume throughput on gathering services and related fees as well as other revenues generated by the Polar and Divide system.
- higher gathering rates associated with amendments to liquids contracts in 2014.
- the previously mentioned decision to discontinue allocating certain corporate general and administrative expenses to our reportable segments.
- the impact of declining commodity prices which negatively affect the margins we earn under percent-of-proceeds arrangements.
- an increase in operation and maintenance expense largely as a result of system buildout on the Polar and Divide system.

Depreciation and amortization increased during 2015 largely as a result of assets placed into service. During 2015, we identified certain events, facts and circumstances which indicated that certain of our property, plant and equipment was impaired; as such, we recognized a long-lived asset impairment. The goodwill impairment recognized in 2015 relates to our determination that all of the goodwill associated with the Polar and Divide reporting unit had been impaired.

Year ended December 31, 2014. Segment adjusted EBITDA increased $14.2 million during 2014 reflecting:

- the impact of higher volume throughput on gathering services and related fees as well as other revenues generated by the Polar and Divide system.

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- higher gathering rates associated with amendments to liquids contracts in 2014.
- increased volumes under our percent-of-proceeds arrangements on the Bison Midstream system.
- higher operating and maintenance expense to support volume growth across the systems.

The increase in depreciation and amortization expense during 2014 was largely driven by an increase in assets placed into service and contract amortization. The goodwill impairment recognized in 2014 relates to our determination that all of the goodwill associated with the Bison Midstream reporting unit had been impaired.

For additional information, see the sections entitled "Non-GAAP Financial Measures—Non-GAAP reconciliations items to note," "Critical Accounting Estimates—Recognition and Impairment of Long-Lived Assets" herein and Notes 2 and 6 to the consolidated financial statements.

Barnett Shale. DFW Midstream, a natural gas gathering system, provides our midstream services for the Barnett Shale reportable segment. On September 30, 2014, DFW Midstream acquired certain natural gas gathering assets (the "Lonestar assets"). The Lonestar assets gather natural gas under two long-term, fee-based gathering agreements. Operating data for our Barnett Shale reportable segment follows.

	Barnett Shale				
	Year ended December 31,			Percentage Change	
	2015	2014	2013	2015 v. 2014	2014 v. 2013
Operating Data:					
Average throughput (MMcf/d)	352	358	391	(2)%	(8)%
Average throughput rate per Mcf	$0.62	$0.59	$0.59	5 %	— %

Volume throughput was flat in 2015 after declining in 2014. The 2015 year-over-year comparison reflects several offsetting effects related to customer drilling and completion activities, the contribution from the Lonestar assets beginning in the fourth quarter of 2014 and a lack of drilling activity by DFW Midstream's anchor customer.

For 2014, the decline in volume throughput reflected the impact of multiple customers temporarily shutting-in several large pad sites to drill or complete new wells as noted above. In addition, 2013 volume throughput benefited early in the year due to the first quarter 2013 commissioning of an additional compressor which increased throughput capacity on the DFW Midstream system by 40 MMcf/d.

The higher average throughput rate in 2015 is primarily the result of a shift in volume mix.

Our customers have a number of wells that have been drilled and are in various stages of the completion process; many of which we expect to begin producing before the third quarter of 2016. In addition, one of our customers recently moved a drilling rig back into our service area to drill new wells which we expect will stimulate volume throughput in the second half of 2016.

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Financial data for our Barnett Shale reportable segment follows.

	Barnett Shale				
	Year ended December 31,			Percentage Change	
	2015	2014	2013	2015 v. 2014	2014 v. 2013
	(In thousands)				
Revenues:					
Gathering services and related fees	$80,461	$79,976	$89,147	1 %	(10)%
Natural gas, NGLs and condensate sales	6,700	13,448	17,190	(50)%	(22)%
Other revenues	881	(423)	(1,013)	*	*
Total revenues	88,042	93,001	105,324	(5)%	(12)%
Costs and expenses:					
Operation and maintenance	25,823	29,438	31,784	(12)%	(7)%
General and administrative	1,297	4,607	6,129	(72)%	(25)%
Depreciation and amortization	15,606	15,657	13,929	— %	12 %
Loss on asset sales	13	—	113	*	*
Long-lived asset impairment	531	5,505	—	*	*
Total costs and expenses	43,270	55,207	51,955	(22)%	6 %
Add:					
Depreciation and amortization	16,392	16,601	14,961		
Adjustments related to MVC shortfall payments	(2,182)	628	1,030		
Loss on asset sales	13	—	113		
Long-lived asset impairment	531	5,505	—		
Segment adjusted EBITDA	$59,526	$60,528	$69,473	(2)%	(13)%

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*Not considered meaningful

Year ended December 31, 2015. Segment adjusted EBITDA decreased $1.0 million during 2015 reflecting:

- the impact of declining natural gas prices on the fuel retainage fee that is paid in-kind by certain of our customers to offset the costs we incur to operate DFW Midstream's electric-drive compression assets.
- lower electricity expense which is reflected in operation and maintenance. We purchase a fixed quantity of power at a fixed heat rate based on prevailing natural gas prices. As a result, the decline in natural gas prices translated into lower electricity expenses. This decline was partially offset by an increase in compression expense.
- the previously mentioned decision to discontinue allocating certain corporate general and administrative expenses to our reportable segments.

Depreciation and amortization increased during 2015 largely as a result of placing the Lonestar assets into service in September 2014.

Year ended December 31, 2014. Segment adjusted EBITDA decreased $8.9 million during 2014 reflecting:

- the impact of declining natural gas prices on the fuel retainage fee that is paid in-kind by certain of our customers to offset the costs we incur to operate DFW Midstream's electric-drive compression assets.
- a decrease in gathering services and related fees due to lower volumes.

Depreciation and amortization increased during 2014 largely as a result of placing the Lonestar assets into service in September 2014.

Piceance Basin. Grand River, a natural gas gathering and processing system, provides our midstream services for the Piceance Basin reportable segment. Red Rock Gathering became part of the Grand River system in connection with the Red Rock Drop Down in March 2014. As noted above, our results include activity for Red Rock Gathering since October 23, 2012, the date on which common control began. For additional information, see the notes to the

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consolidated financial statements.
Operating data for our Piceance Basin reportable segment follows.

	Piceance Basin				
	Year ended December 31,			Percentage Change	
	2015	2014	2013	2015 v. 2014	2014 v. 2013
Operating Data:					
Average throughput (MMcf/d)	602	660	646	(9)%	2 %
Average throughput rate per Mcf	$0.53	$0.49	$0.40	8 %	23 %

Volume throughput during 2015 was favorably impacted by new pad site connections for WPX Energy, Inc. and Ursa Resources Group II as well as the March 2014 start-up of a cryogenic processing plant servicing production from Black Hills Corporation. Volume throughput on the Legacy Grand River system declined in 2014 primarily as a result of Encana's continued suspension of drilling activities, which began in the fourth quarter of 2013.
The aggregate average throughput rate increased during 2015 and 2014 largely as a result of a shift in volume throughput mix. Volume growth from Red Rock Gathering's anchor customers continues to offset volume declines on the Legacy Grand River system and thereby has translated into higher average gathering rates per Mcf.
Financial data for our Piceance Basin reportable segment follows.

	Piceance Basin				
	Year ended December 31,			Percentage Change	
	2015	2014	2013	2015 v. 2014	2014 v. 2013
	(Dollars in thousands, except fee-rate data)				
Revenues:					
Gathering services and related fees	$151,667	$115,869	$94,112	31 %	23 %
Natural gas, NGLs and condensate sales	11,854	27,606	23,865	(57)%	16 %
Other revenues	5,401	9,062	9,296	(40)%	(3)%
Total revenues	168,922	152,537	127,273	11 %	20 %
Costs and expenses:					
Cost of natural gas and NGLs	8,308	17,935	13,197	(54)%	36 %
Operation and maintenance	32,196	33,111	33,964	(3)%	(3)%
General and administrative	2,361	8,732	11,566	(73)%	(25)%
Depreciation and amortization	45,018	40,965	35,527	10 %	15 %
(Gain) loss on asset sales	(190)	146	—	*	*
Long-lived asset impairment	1,220	—	—	*	*
Goodwill impairment	45,478	—	—	*	*
Total costs and expenses	134,391	100,889	94,254	33 %	7 %
Other income	—	1,185	—	*	*
Add:					
Depreciation and amortization	45,018	40,965	35,527		
Adjustments related to MVC shortfall payments	(21,590)	15,194	12,395		
Loss on asset sales	24	146	—		
Long-lived asset impairment	1,220	—	—		
Goodwill impairment	45,478	—	—		
Less:					
Gain on asset sales	214	—	—		
Impact of purchase price adjustments	—	1,185	—		
Segment adjusted EBITDA	$104,467	$107,953	$80,941	(3)%	33 %

* Not considered meaningful

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Year ended December 31, 2015. Segment adjusted EBITDA decreased $3.5 million during 2015 reflecting:

- the impact of declining commodity prices which negatively impacted the margins that we earn from our percent-of-proceeds contracts.
- lower gathering services revenue from our anchor customer.
- the previously mentioned decision to discontinue allocating certain corporate general and administrative expenses to our reportable segments.
- an increase in anticipated MVC shortfall payments due to increasing rate and volume commitment provisions in certain gas gathering agreements.

Gathering services and related fees also reflect the recognition of revenue that had been previously deferred in connection with an MVC arrangement, which was determined to no longer be recoverable by the customer. Because we exclude the impacts of adjustments related to MVC shortfall payments from our definition of segment adjusted EBITDA, this metric was not impacted by the 2015 deferred revenue release. (See Note 7 to the consolidated financial statements for additional information.) Other revenues and operation and maintenance also reflect the effect of a decrease in certain electricity expenses, which, due to their pass-through nature, have no impact on segment adjusted EBITDA. Depreciation and amortization increased during the year ended December 31, 2015 largely as a result of an increase in contract amortization for Grand River's anchor customer and the March 2014 commissioning of a cryogenic processing plant. During 2015, we identified certain events, facts and circumstances which indicated that certain of our property, plant and equipment was impaired; as such, we recognized a long-lived asset impairment. The goodwill impairment recognized in 2015 relates to our determination that all of the goodwill associated with the Grand River reporting unit had been impaired.

Year ended December 31, 2014. Segment adjusted EBITDA increased $27.0 million during 2014 reflecting:

- higher gathering services and related fees, largely due to the proportionate contribution of higher margin volume throughput from certain customers and the first quarter 2014 commissioning of a natural gas processing plant.
- an increase in anticipated MVC shortfall payments due to increasing rate and volume commitment provisions in certain gas gathering agreements.
- a decline in operation and maintenance.

Other revenues and operation and maintenance also reflect the effect of a decrease in certain electricity expenses, which, due to their pass-through nature, have no impact on segment adjusted EBITDA. Depreciation and amortization increased during 2014 largely as a result an increase in contract amortization and assets placed into service on the Grand River system. Other income represents the write off of certain balances that had been previously recognized in connection with the purchase accounting for the Legacy Grand River system.

For additional information, see the sections entitled "Non-GAAP Financial Measures—Non-GAAP reconciliations items to note," "Critical Accounting Estimates—Recognition and Impairment of Long-Lived Assets" herein and Notes 2, 6 and 15 to the consolidated financial statements.

Corporate. Corporate represents those results that are not specifically attributable to a reportable segment or that have not been allocated to our reportable segments, including certain general and administrative expense items, transaction costs and interest expense. Items to note follow.

	Corporate Year ended December 31,			Percentage Change	
	2015	2014	2013	2015 v. 2014	2014 v. 2013
	(In thousands)				
Costs and expenses:					
General and administrative	$29,156	$15,031	$9,368	94 %	60 %
Transaction costs	790	730	2,841	8 %	(74)%
Interest expense	48,616	40,159	19,173	21 %	109 %

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General and Administrative. The increase in general and administrative expense during the year ended December 31, 2015, largely reflects the impact of our decision to discontinue allocating certain expenses, primarily salaries, benefits, incentive compensation and rent expense, to our operating segments.
General and administrative expense increased during the year ended December 31, 2014, largely as a result of an increase in salaries, benefits and incentive compensation primarily due to increased head count, an increase in professional expenses associated with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002 and our adoption of COSO 2013.
Transaction Costs. Transaction costs recognized primarily relate to financial and legal advisory costs associated with the Polar and Divide Drop Down in 2015, the Red Rock Drop Down in 2014 and the Bison Drop Down and the acquisition of Mountaineer Midstream in 2013.
Interest Expense. The increase in interest expense during the year ended December 31, 2015 was primarily driven by our July 2014 issuance of 5.5% senior notes.
The increase in interest expense during the year ended December 31, 2014 was primarily driven by our June 2013 issuance of 7.5% senior notes.

Non-GAAP Financial Measures
EBITDA, adjusted EBITDA and distributable cash flow are not financial measures presented in accordance with GAAP. We define EBITDA as net income or loss, plus interest expense, income tax expense, and depreciation and amortization, less interest income and income tax benefit. We define adjusted EBITDA as EBITDA plus adjustments related to MVC shortfall payments, impairments and other noncash expenses or losses, less other noncash income or gains. We define distributable cash flow as adjusted EBITDA plus cash interest received, less cash interest paid, senior notes interest adjustment, cash taxes paid and maintenance capital expenditures. 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 or loss 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 noncash charges, the assets being depreciated and amortized will often have to be replaced in the future, and EBITDA, adjusted EBITDA and distributable cash flow do not reflect any cash requirements for such replacements; and
- our computations of EBITDA, adjusted EBITDA and distributable cash flow may not be comparable to other similarly titled measures of other companies.

We compensate for the limitations of EBITDA, adjusted EBITDA and distributable cash flows as analytical tools by reviewing the comparable GAAP financial measures, understanding the differences between the financial measures and incorporating these data points into our decision-making process.
EBITDA, adjusted EBITDA or distributable cash flow should not be considered in isolation or as a substitute for analysis of our results as reported under GAAP. Because EBITDA, adjusted EBITDA and distributable cash flow may be defined differently by other companies in our industry, our definitions of these non-GAAP financial measures may not be comparable to similarly titled measures of other companies, thereby diminishing their utility.

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Non-GAAP reconciliations items to note. The following items should be noted when reviewing our non-GAAP reconciliations:

- Interest expense presented in the net income-basis non-GAAP reconciliation includes amortization of deferred loan costs while interest expense presented in the cash flow-basis non-GAAP reconciliation is adjusted to exclude amortization of deferred loan costs. See the consolidated statements of cash flows for additional information.
- Depreciation and amortization includes the favorable and unfavorable gas gathering contract amortization expense reported in other revenues.
- 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 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. See Notes 2 and 3 to the consolidated financial statements for additional information.
- Goodwill impairments recognized during 2015 and 2014 are discussed in the sections entitled "Results of Operations" and "Critical Accounting Estimates—Recognition and Impairment of Long-Lived Assets" as well as Note 6 to the consolidated financial statements.
- Long-lived asset impairments recognized during 2015 and 2014 are discussed in the sections entitled "Results of Operations" and "Critical Accounting Estimates—Recognition and Impairment of Long-Lived Assets" as well as Note 4 to the consolidated financial statements.
- The impact of purchase price adjustments reflects certain balances previously recognized in connection with the Predecessor's purchase accounting for the Legacy Grand River system that we wrote off during the fourth quarter of 2014. This write off was recognized in other income. See "Results of Operations—Piceance Basin" and Note 15 to the consolidated financial statements for additional information.
- Senior notes interest adjustment represents the net of interest expense accrued and paid during the period. See "Liquidity and Capital Resources—Long-Term Debt" and Note 8 to the consolidated financial statements for additional information.
- 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.
- As a result of accounting for our drop down transactions similar to a pooling of interests, EBITDA, adjusted EBITDA, and distributable cash flow reflect the historical operations, financial position and cash flows of contributed subsidiaries for the periods beginning with the date that common control began and ending on the date that the respective drop down closed. See Notes 1 and 15 to the consolidated financial statements for additional information.
- EBITDA, adjusted EBITDA, distributable cash flow and net cash provided by operating activities include transaction costs. These unusual expenses are settled in cash. For additional information, see "Results of Operations—Corporate" herein.

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

	Year ended December 31,		
	2015	2014	2013
	(In thousands)		
Reconciliation of net income to EBITDA, adjusted EBITDA and distributable cash flow:			
Net (loss) income	$(186,809)	$(14,734)	$52,837
Add:			
Interest expense	48,616	40,159	19,173
Income tax expense	—	631	729
Depreciation and amortization	96,975	88,293	71,606
Less:			
Interest income	2	4	5
Income tax benefit	676	—	—
EBITDA	$(41,896)	$114,345	$144,340
Add:			
Adjustments related to MVC shortfall payments	(11,902)	26,565	17,025
Unit-based compensation	6,259	5,036	3,846
Loss on asset sales	42	442	113
Long-lived asset impairment	9,305	5,505	—
Goodwill impairment	248,851	54,199	—
Less:			
Gain on asset sales	214	—	—
Impact of purchase price adjustment	—	1,185	—
Adjusted EBITDA	$210,445	$204,907	$165,324
Add cash interest received	2	4	5
Less:			
Cash interest paid	48,947	31,524	9,016
Senior notes interest adjustment	(1,421)	6,733	12,125
Cash taxes paid	—	—	660
Maintenance capital expenditures	9,548	16,336	15,071
Distributable cash flow	$153,373	$150,318	$128,457

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

	Year ended December 31,		
	2015	2014	2013
	(In thousands)		
Reconciliation of net cash provided by operating activities to EBITDA, adjusted EBITDA and distributable cash flow:			
Net cash provided by operating activities	$165,950	$154,997	$140,469
Add:			
Interest expense, excluding deferred loan costs	45,359	37,389	16,927
Income tax expense	—	631	729
Impact of purchase price adjustments	—	1,185	—
Changes in operating assets and liabilities	11,716	(14,671)	(9,821)
Gain on asset sales	214	—	—
Less:			
Unit-based compensation	6,259	5,036	3,846
Interest income	2	4	5
Income tax benefit	676	—	—
Loss on asset sales	42	442	113
Long-lived asset impairment	9,305	5,505	—
Goodwill impairment	248,851	54,199	—
EBITDA	$(41,896)	$114,345	$144,340
Add:			
Adjustments related to MVC shortfall payments	(11,902)	26,565	17,025
Unit-based compensation	6,259	5,036	3,846
Loss on asset sales	42	442	113
Long-lived asset impairment	9,305	5,505	—
Goodwill impairment	248,851	54,199	—
Less:			
Gain on asset sales	214	—	—
Impact of purchase price adjustment	—	1,185	—
Adjusted EBITDA	$210,445	$204,907	$165,324
Add cash interest received	2	4	5
Less:			
Cash interest paid	48,947	31,524	9,016
Senior notes interest adjustment	(1,421)	6,733	12,125
Cash taxes paid	—	—	660
Maintenance capital expenditures	9,548	16,336	15,071
Distributable cash flow	$153,373	$150,318	$128,457

Liquidity and Capital Resources

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 instruments.

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Capital Markets Activity

November 2013 Shelf Registration Statement. In October 2013, we filed a shelf registration statement 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 a subsidiary of Summit Investments in accordance with our obligations under several registration rights agreements. In November 2013, the SEC declared our shelf registration statement effective.

In March 2014, we completed an underwritten public offering of 10,350,000 common units at a price of $38.75 per unit, of which 5,300,000 common units were offered by the Partnership and 5,050,000 common units were offered by a subsidiary of Summit Investments. Concurrent with the offering, our general partner made a capital contribution to maintain its 2% general partner interest. We used the proceeds from our primary offering of common units and the general partner capital contribution to fund a portion of the purchase of Red Rock Gathering.

In September 2014, a subsidiary of Summit Investments completed an underwritten public offering of 4,347,826 SMLP common units. We did not receive any proceeds from this offering.

On May 13, 2015, we completed an underwritten public offering of 6,500,000 common units at a price of $30.75 per unit pursuant to an effective shelf registration statement on Form S-3 previously filed with the SEC (the "May 2015 Equity Offering"). On May 22, 2015, the underwriters exercised in full their option to purchase an additional 975,000 common units from us at a price of $30.75 per unit. Concurrent with both transactions, our general partner made a capital contribution to us to maintain its 2% general partner interest. We used the proceeds from the May 13, 2015 transaction to partially fund the Polar and Divide Drop Down. We used $25.0 million of the $29.0 million proceeds from the exercise of the underwriters' option to pay down our revolving credit facility. Following the May 2015 Equity Offering and the exercise of the underwriters' option, we can issue up to $464.8 million of debt and equity securities in primary offerings and 5,293,571 common units pursuant to this shelf registration statement.

In June 2015, we executed an equity distribution agreement and filed a prospectus and a prospectus supplement with the SEC for the issuance and sale from time to time of SMLP common units having an aggregate offering price of up to $150.0 million (the "June 2015 ATM Program"). These sales will be made (i) pursuant to the terms of the equity distribution agreement between us and the sales agents named therein and (ii) by means of ordinary brokers' transactions at market prices, in block transactions or as otherwise agreed between us and the sales agents. Sales of our common units may be made in negotiated transactions or transactions that are deemed to be "at-the-market offerings" as defined by SEC Rules. There were no transactions under the June 2015 ATM Program during the period from inception to December 31, 2015.

July 2014 Shelf Registration Statement. In July 2014, we filed a registration statement with the SEC to issue an unlimited amount of debt and equity securities and shortly thereafter completed a public offering of $300.0 million aggregate principal 5.5% senior notes due 2022. We used the proceeds to repay a portion of the outstanding borrowings under our revolving credit facility.

Private Offerings of Debt and Equity. In June 2013, we issued $300.0 million unregistered 7.5% senior unsecured notes and guarantees notes maturing July 1, 2021 (the "7.5% senior notes") and used the net proceeds to partially fund the acquisition of Mountaineer Midstream. In March 2014, the SEC declared our registration statement to exchange all of the unregistered 7.5% senior notes and guarantees for registered senior notes and guarantees with substantially identical terms effective. In April 2014, the exchange period concluded with 100% of the unregistered senior notes being exchanged for registered notes.

In June 2013, we issued common limited partner units and general partner interests to a subsidiary of Summit Investments to partially fund the Bison Drop Down and the acquisition of Mountaineer Midstream.

For additional information, see Notes 1, 8, 10 and 15 to the consolidated financial statements.

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 the assets of Summit Holdings and its subsidiaries 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. As of December 31, 2015, the outstanding balance of the revolving credit facility was $344.0 million and the unused portion totaled $356.0 million. As of December 31, 2015, we were in compliance with the covenants in the revolving credit facility. There were no defaults or events of default during 2015.

Senior Notes. In July 2014, Summit Holdings and its 100% owned finance subsidiary, Summit Midstream Finance Corp. ("Finance Corp.," together with Summit Holdings, the "Co-Issuers") co-issued $300.0 million of 5.50% senior

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unsecured notes maturing August 15, 2022 (the "5.5% senior notes"). In June 2013, the Co-Issuers co-issued $300.0 million of 7.50% senior unsecured notes maturing July 1, 2021 (the "7.5% senior notes"). The 7.5% senior notes were initially sold in reliance on Rule 144A and Regulation S under the Securities Act. Effective as of April 7, 2014, all of the holders of our 7.5% senior notes exchanged their unregistered 7.5% senior notes and the guarantees of those notes for identical registered notes and guarantees. There were no defaults or events of default during 2014 on either series of senior notes.

For additional information on our revolving credit facility and senior notes, see Note 8 to the consolidated financial statements.

Cash Flows

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

	Year ended December 31,		
	2015	2014	2013
	(In thousands)		
Net cash provided by operating activities	$165,950	$154,997	$140,469
Net cash used in investing activities	(406,402)	(536,367)	(592,393)
Net cash provided by financing activities	233,359	387,517	460,947
Net change in cash and cash equivalents	$(7,093)	$6,147	$9,023

Operating activities. Cash flows from operating activities increased by $11.0 million for the year ended December 31, 2015 primarily due to cash received as a result of MVCs. The impact of these cash receipts was largely offset by an increase in interest due to the 5.5% senior notes and other operating activities.

Cash flows from operating activities increased by $14.5 million for the year ended December 31, 2014 largely due to cash received as a result of MVCs.

Investing activities. Cash flows used in investing activities for the year ended December 31, 2015 were related primarily to: (i) the Polar and Divide Drop Down, (ii) the ongoing expansion of compression capacity on the Bison Midstream system, (iii) ongoing expansion of the Polar and Divide system, including the Stampede Lateral and (iv) pipeline construction projects to connect new receipt points on the Grand River and Bison Midstream systems.

Cash flows used in investing activities for the year ended December 31, 2014 primarily reflect the Partnership's acquisition of Red Rock Gathering from a subsidiary of Summit Investments and build out of the Polar and Divide system. Additional expenditures for the year ended December 31, 2014 primarily reflect construction of a processing plant on the Grand River system, projects to expand compression capacity on the Bison Midstream system, adding pipeline on the Mountaineer Midstream system, the February 2014 commissioning of a new natural gas treating facility on the DFW Midstream system and the purchase of the Lonestar assets.

Cash flows used in investing activities for the year ended December 31, 2013 were largely due to the acquisitions of Bison Midstream and Mountaineer Midstream and construction of the Polar and Divide system. Additional expenditures in 2013 reflect the construction of seven miles 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 began construction on a new 150 gallon per minute natural gas treating facility on the DFW Midstream system, which was commissioned in the first quarter of 2014.

Financing activities. Details of cash flows provided by financing activities were as follows:

Net cash used in financing activities for the year ended December 31, 2015 was primarily composed of the following:

- Net proceeds from an offering of common units in May 2015, which were used to partially fund the Polar and Divide Drop Down;
- Net borrowings under our revolving credit facility, including $92.5 million to partially fund the Polar and Divide Drop Down; and
- Distributions declared and paid in 2015.

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Net cash provided by financing activities for the year ended December 31, 2014 was primarily composed of the following:

- Proceeds from the 5.5% senior notes issuance, the net of which was used to pay down our revolving credit facility. We incurred loan costs of $5.1 million in connection with their issuance which will be amortized over the life of the notes;
- Borrowings of $100.0 million under our revolving credit facility to partially fund the Red Rock Drop Down;
- Net proceeds from an offering of common units in March 2014, which were used to partially fund the Red Rock Drop Down;
- Distributions declared and paid in 2014; and
- Cash advances to support the buildout of the Polar and Divide system.

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

- Distributions declared and paid in 2013;
- Borrowings 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;
- Proceeds from the 7.5% senior notes issuance, the net of which was used to pay down our revolving credit facility. We incurred loan costs of $7.4 million in connection with the senior notes issuance which will be amortized over the life of the notes;
- Payments of $294.2 million on our revolving credit facility, all of which was funded by the 7.5% senior notes issuance;
- Issuance of $98.0 million of common units and $2.0 million of general partner interests to Summit Investments for cash to partially fund the Mountaineer Acquisition; and
- Cash advances to support the buildout of the Polar and Divide system.

Contractual Obligations

The table below summarizes our contractual obligations as of December 31, 2015:

	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
	(In thousands)				
Long-term debt and interest payments (1)	$1,229,089	$50,859	$444,730	$78,000	$655,500
Purchase obligations (2)	22,949	21,661	1,188	100	—
Total contractual obligations	$1,252,038	$72,520	$445,918	$78,100	$655,500

(1) For the purpose of calculating future interest on the revolving credit facility, assumes no change in balance or rate from December 31, 2015. Includes a 0.50% commitment fee on the unused portion of the revolving credit facility. See Note 8 to the consolidated financial statements for additional information.
(2) Represents agreements to purchase goods or services that are enforceable and legally binding.

Operating leases. A substantial majority of the operating leases that support our operations have been entered into by Summit Investments with the associated rent expense allocated to us. Future minimum lease payments associated with operating leases in the Partnership's name are immaterial. See Note 14 to the consolidated financial statements for additional information.

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Capital Requirements

The table below summarizes our capital expenditures by reportable segment and in total for the years ended December 31.

	Year ended December 31,		
	2015	2014	2013
	(In thousands)		
Capital expenditures:			
Marcellus Shale	$1,306	$33,866	$1,822
Williston Basin	90,234	139,422	99,983
Barnett Shale	6,875	14,567	29,534
Piceance Basin	19,263	32,505	50,709
Total reportable segment capital expenditures	117,678	220,360	182,048
Corporate	429	460	930
Total capital expenditures	$118,107	$220,820	$182,978

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.

For the year ended December 31, 2015, SMLP recorded total capital expenditures of $118.1 million, which included $9.5 million of maintenance capital expenditures.

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 instruments.

We believe that our existing $700.0 million revolving credit facility, which had $356.0 million of available capacity at December 31, 2015, along with commitments to increase its borrowing capacity by $550.0 million contingent upon and concurrent with the Initial Close of the 2016 Drop Down (see Note 8 to the consolidated financial statements), together with financial support from our Sponsor and/or access to the debt and equity capital markets, will be adequate to finance our acquisition strategy for the foreseeable future without adversely impacting our liquidity or our ability to make quarterly cash distributions to our unitholders.

Distributions, Including IDRs

Based on the terms of our partnership agreement, we expect to distribute most of the cash generated by our operations to our unitholders. With respect to our payment of IDRs to the general partner, we reached the second target distribution in connection with the distribution declared in respect of the fourth quarter of 2013. We reached the third target distribution in connection with the distribution declared in respect of the second quarter of 2014. For additional information, see "Our Cash Distribution Policy and Restrictions on Distributions" in Item 5. Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities and Note 10 to the consolidated financial statements.

Credit and Counterparty Concentration Risks

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.

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Given the current environment, certain of our customers may be temporarily unable to meet their current obligations. While this may cause disruption to cash flows, we believe that we are properly positioned to deal with the potential disruption because the vast majority of our gathering assets are strategically positioned at the beginning of the midstream value chain. The majority of our infrastructure is connected directly to our customer's wellheads and pad sites, which means our gathering systems are typically the first third-party infrastructure through which our customer's commodities flow and, in many cases, the only way for our customers to get their production to market.

We estimate the quarterly impact of expected MVC shortfall payments for inclusion in our calculation of adjusted EBITDA. As such, we have exposure due to nonperformance under our MVC contracts whereby a customer, who was not meeting their MVCs, does not have the wherewithal to make its MVC shortfall payments when they become due. We typically receive payment for all prior-year MVC shortfall billings in the quarter immediately following billing. Therefore, our exposure to risk of nonperformance is limited to and accumulates during the current year-to-date contracted measurement period. The components of adjustments related to MVC shortfall payments by reportable segment for the year ended December 31, 2015 follow.

	Williston Basin	Barnett Shale	Piceance Basin	Total
	(In thousands)			
Adjustments related to MVC shortfall payments:				
Net change in deferred revenue for MVC shortfall payments (1)	$11,870	$(1,700)	$(21,623)	$(11,453)
Expected MVC shortfall payments (2)	—	(482)	33	(449)
Total adjustments related to MVC shortfall payments	$11,870	$(2,182)	$(21,590)	$(11,902)

(1) See Notes 3 and 7 for additional information on the changes in deferred revenue.

(2) As of December 31, 2015, accounts receivable included $40.2 million of total shortfall payment billings, of which $12.7 million related to shortfall billings associated with MVC arrangements that can be utilized to offset gathering fees in future periods.

For additional information, see Notes 2, 3, 7 and 9 to the consolidated financial statements.

Off-Balance Sheet Arrangements

We had no off-balance sheet arrangements as of or during the year ended December 31, 2015.

Critical Accounting 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 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 amortizing intangible assets and goodwill.

Property, Plant and Equipment and Amortizing Intangible Assets. As of December 31, 2015, we had net property, plant and equipment with a carrying value of approximately $1.5 billion and net amortizing intangible assets with a carrying value of approximately $438.1 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 as well as in connection with any goodwill impairment evaluations.

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With respect to property, plant and equipment and our amortizing 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. Any impairment determinations, including those recognized in 2015 and 2014 and disclosed in Note 4 to the consolidated financial statements, involve significant assumptions and judgments. Differing assumptions regarding any of these inputs could have a significant effect on the various valuations. As such, the fair value measurements utilized within these estimates are classified as non-recurring Level 3 measurements in the fair value hierarchy because they are not observable from objective sources. Due to the volatility of the inputs used, we cannot predict the likelihood of any future impairment.

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

Goodwill. We evaluate goodwill for impairment annually on September 30 and 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 value, including goodwill.

2014 Impairment Evaluations. We performed our 2014 annual goodwill impairment analysis as of September 30 and concluded that none of our goodwill had been impaired.

During the latter part of the fourth quarter of 2014, the declines in prices for natural gas, NGLs and crude oil accelerated, negatively impacting producers in each of our areas of operation. As a result, we considered whether any of our goodwill could have been impaired. In connection with this assessment, we concluded that a fourth quarter triggering event had occurred which required that we test the goodwill associated with our Polar and Divide and Bison Midstream reporting units for impairment as of December 31, 2014. See Notes 2 and 6 for additional information.

2015 Impairment Evaluations. We performed our 2015 annual goodwill impairment analysis as of September 30 and concluded that none of our goodwill had been impaired.

During the latter part of the fourth quarter of 2015 and the early part of the first quarter of 2016, the declines in forward prices for natural gas, NGLs and crude oil accelerated significantly. As a result, the energy sector's public debt and equity market experienced increased volatility, particularly for comparable companies operating in the midstream services sector. Additionally, during this period, the values of our publicly traded equity and debt instruments decreased as did those of comparable midstream companies. Due to (i) the increased market volatility, (ii) the decrease in market values of comparable companies, (iii) the continued trend of falling commodity prices and (iv) the finalization of our annual financial and operating plans which took into account changes resulting from expected levels of drilling activity, we concluded that a triggering event occurred which required that we test the goodwill associated with our Grand River and Polar and Divide reporting units for impairment as of December 31, 2014. See Notes 2 and 6 for additional information.

Minimum Volume Commitments

Certain of our gas gathering agreements provide for a monthly, quarterly or annual MVC from our customers. As of December 31, 2015, we had MVCs totaling 1.2 Bcfe/d through 2020.

Under these MVCs, our customers agree to ship and/or process a minimum volume of production 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 contracted measurement 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 contracted measurement periods to the extent that such customer's throughput volumes in a subsequent contracted measurement period exceed its MVC for that period.

We recognize customer billings for obligations under their MVCs as revenue when the obligations are billable under the contract and the customer does not have the right to utilize shortfall payments to offset gathering fees in excess of its MVCs in subsequent periods.

We billed $58.2 million of MVC shortfall payments to customers that did not meet their MVCs during 2015. For those customers that do not have credit banking mechanisms in their gathering agreements, or have no ability to use MVC shortfall payments as credits, the MVC shortfall payments from these customers are accounted for as gathering revenue in the period that they are earned. We recognized $39.5 million of gathering revenue due to the credit bank expiration of previous MVC shortfall payments. Of the gathering revenue, $37.1 million is related to the deferred revenue recognition associated with a certain Piceance Basin customer for which we determined that it

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would be remote that it could ship volumes in excess of its future MVC as an offset to future gathering fees. As such, the deferred revenue associated with this customer, as reflected on the balance sheet, was recognized as revenue on the income statement.

MVC shortfall payment adjustments in 2015 totaled $(0.4) million and included adjustments related to future anticipated shortfall payments from certain customers in the Piceance Basin, Williston Basin and Barnett Shale segments. The net impact of our MVC shortfall payment mechanisms increased adjusted EBITDA by $57.7 million in 2015.

The following table presents the impact of our MVC activity by reportable segment during the year ended December 31, 2015.

	Year ended December 31, 2015			
	MVC billings	Gathering revenue	Adjustments to MVC shortfall payments	Net impact to adjusted EBITDA
	(In thousands)			
Net change in deferred revenue:				
Williston Basin	$11,897	$27	$11,870	$11,897
Barnett Shale	677	2,377	(1,700)	677
Piceance Basin	15,508	37,131	(21,623)	15,508
Total change in deferred revenue	$28,082	$39,535	$(11,453)	$28,082
MVC shortfall payment adjustments:				
Marcellus Shale	$3,237	$3,237	$—	$3,237
Williston Basin	—	—	—	—
Barnett Shale	1,142	1,142	(482)	660
Piceance Basin	25,704	25,704	33	25,737
Total MVC shortfall payment adjustments	$30,083	$30,083	$(449)	$29,634
Total	$58,165	$69,618	$(11,902)	$57,716

Deferred Revenue. 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 also recognize deferred revenue when it is determined that a given amount of MVC shortfall payments cannot be recovered by offsetting gathering or processing fees in subsequent contracted measurement periods. In making this determination, we consider both quantitative and qualitative facts and circumstances, including, but not limited to, contract terms, capacity of the associated pipeline or receipt point and/or expectations regarding future investment, drilling and production.

We classify deferred revenue as a current liability for arrangements where the expiration of a customer's right to utilize shortfall payments is twelve 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. As of December 31, 2015, current deferred revenue totaled $0.7 million. Noncurrent deferred revenue totaled $45.5 million at December 31, 2015 and represents amounts that provide these customers the ability to offset their gathering fees, as determined by the MVC contract, to the extent that their throughput volumes exceed their MVC.

Adjustments for MVC Shortfall Payments. Adjustments related to MVC shortfall payments account for:

- the net increases or decreases in deferred revenue for MVC shortfall payments and
- our inclusion of expected annual MVC shortfall payments. We include a proportional amount of these historical or expected MVC shortfall payments in our calculation of segment adjusted EBITDA each quarter prior to the quarter in

which we actually recognize the shortfall payment. These adjustments have not been billed to our customers and are not recognized in our consolidated financial statements.

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We estimate expected annual MVC shortfall payments based on assumptions including, but not limited to, contract terms, historical volume throughput data and expectations regarding future investment, drilling and production. For additional information, see Notes 2, 3 and 7 to the consolidated financial statements and the "Results of Operations" and "Liquidity and Capital Resources—Credit and Counterparty Concentration Risks" sections herein.

Forward-Looking Statements

Investors are cautioned that certain statements contained in this report 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 "will continue," "will likely result," and similar expressions, or future conditional verbs such as "may," "will," "should," "wou and "could." In addition, any statement concerning future financial performance (including future revenues, earnings or growth rates), ongoing business strategies or prospects, and possible actions taken by us, Summit Investments or our Sponsor, are also forward-looking statements. These forward-looking statements involve external risks and uncertainties, including, but not limited to, those described in Item 1A. Risk Factors included in this report. Forward-looking statements are based on current expectations and projections about future events and are inherently subject to a variety of risks and uncertainties, many of which are beyond the control of our management team. All forward-looking statements in this report and subsequent written and oral forward-looking statements attributable to us, or to persons acting on our behalf, are expressly qualified in their entirety by the cautionary statements in this paragraph. These risks and uncertainties include, among others:

- fluctuations in natural gas, NGLs and crude oil prices;
- the extent and success of drilling efforts, as well as the extent and quality of natural gas and crude oil volumes produced within proximity of our assets;
- failure or delays by our customers in achieving expected production in their natural gas, crude oil and produced water projects;
- competitive conditions in our industry and their impact on our ability to connect hydrocarbon 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 and our ability to enforce the terms and conditions of certain of our gathering agreements in the event of a bankruptcy of one or more of our customers;
- our ability to acquire any assets owned by third parties, which is subject to a number of factors, including prevailing conditions and outlook in the natural gas, NGL and crude oil industries and markets, and our ability to obtain financing on acceptable terms from the credit and/or capital markets or other sources;
- 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;
- natural disasters, accidents, weather-related delays, casualty losses and other matters beyond our control;
- operational risks and hazards inherent in the gathering, treating and/or processing of natural gas, crude oil and produced water;

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- 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, safety and climate change requirements;
- the effects of litigation;
- changes in general economic conditions; and
- certain factors discussed elsewhere in this report.

Developments in any of these areas could cause actual results to differ materially from those anticipated or projected or cause a significant reduction in the market price of our common units 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 7A. Quantitative and Qualitative Disclosures About Market Risk.

Interest Rate Risk

Our current interest rate risk exposure is largely related to our debt portfolio. As of December 31, 2015, we had $600.0 million of fixed-rate senior notes and $344.0 million of variable rate debt (see Note 8 to the consolidated financial statements for additional information). While existing fixed-rate debt mitigates the downside impact of fluctuations in interest rates, future issuances of long-term debt could be impacted by increases in interest rates, which could result in higher overall interest costs. In addition, the borrowings under our revolving credit facility, which have a variable interest rate, also expose us to the risk of increasing interest rates. For the year ended December 31, 2015, a hypothetical 1.0% increase (decrease) in interest rates would have increased (decreased) our interest expense by approximately $2.7 million assuming no changes in amounts drawn or other variables under our revolving credit facility or senior notes.

Commodity Price Risk

We currently generate a substantial majority of our revenues pursuant to primarily long-term and 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 percent-of-proceeds 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.

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Item 8. Financial Statements and Supplementary Data.

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

We have audited the accompanying consolidated balance sheets of Summit Midstream Partners, LP and subsidiaries (the "Partnership") as of December 31, 2015 and 2014, and the related consolidated statements of operations, partners' capital and cash flows for each of the three years in the period ended December 31, 2015. 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. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes 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, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America.
As discussed in Note 3 to the consolidated financial statements, the disclosures in the accompanying financial statements have been retrospectively adjusted for a change in the composition of reportable segments.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Partnership's internal control over financial reporting as of December 31, 2015, based on the criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2016 expressed an unqualified opinion on the Partnership's internal control over financial reporting.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 26, 2016

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SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2015	2014
	(In thousands)	
Assets		
Current assets:		
Cash and cash equivalents	$19,411	$26,504
Accounts receivable	84,022	89,201
Other current assets	3,210	3,517
Total current assets	106,643	119,222
Property, plant and equipment, net	1,463,802	1,414,350
Intangible assets, net	438,093	477,734
Goodwill	16,211	265,062
Other noncurrent assets	15,782	17,353
Total assets	$2,040,531	$2,293,721
Liabilities and Partners' Capital		
Current liabilities:		
Trade accounts payable	$18,971	$24,855
Due to affiliate	1,149	2,711
Deferred revenue	677	2,377
Ad valorem taxes payable	9,890	9,118
Accrued interest	17,483	18,858
Other current liabilities	11,464	13,550
Total current liabilities	59,634	71,469
Long-term debt	944,000	808,000
Deferred revenue	45,486	55,239
Other noncurrent liabilities	7,169	7,292
Total liabilities	1,056,289	942,000
Commitments and contingencies (Note 14)		
Common limited partner capital (42,063 units issued and outstanding at December 31, 2015 and 34,427 units issued and outstanding at December 31, 2014)	744,977	649,060
Subordinated limited partner capital (24,410 units issued and outstanding at December 31, 2015 and 2014)	213,631	293,153
General partner interests (1,355 units issued and outstanding at December 31, 2015 and 1,201 units issued and outstanding at December 31, 2014)	25,634	24,676
Summit Investments' equity in contributed subsidiaries	—	384,832
Total partners' capital	984,242	1,351,721
Total liabilities and partners' capital	$2,040,531	$2,293,721

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

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SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year ended December 31,		
	2015	2014	2013
	(In thousands, except per-unit amounts)		
Revenues:			
Gathering services and related fees	$310,829	$255,211	$213,979
Natural gas, NGLs and condensate sales	42,079	97,094	88,185
Other revenues	18,411	20,398	21,522
Total revenues	371,319	372,703	323,686
Costs and expenses:			
Cost of natural gas and NGLs	31,398	72,415	68,037
Operation and maintenance	87,285	88,927	77,114
General and administrative	36,544	38,269	32,273
Transaction costs	790	730	2,841
Depreciation and amortization	96,189	87,349	70,574
(Gain) loss on asset sales, net	(172)	442	113
Long-lived asset impairment	9,305	5,505	—
Goodwill impairment	248,851	54,199	—
Total costs and expenses	510,190	347,836	250,952
Other income	2	1,189	5
Interest expense	(48,616)	(40,159)	(19,173)
(Loss) income before income taxes	(187,485)	(14,103)	53,566
Income tax benefit (expense)	676	(631)	(729)
Net (loss) income	$(186,809)	$(14,734)	$52,837
Less net income attributable to Summit Investments	5,403	9,258	9,253
Net (loss) income attributable to SMLP	(192,212)	(23,992)	43,584
Less net (loss) income attributable to general partner, including IDRs	3,398	3,125	1,035
Net (loss) income attributable to limited partners	$(195,610)	$(27,117)	$42,549
(Loss) earnings per limited partner unit:			
Common unit – basic	$(3.20)	$(0.49)	$0.86
Common unit – diluted	$(3.20)	$(0.49)	$0.86
Subordinated unit – basic and diluted	$(2.88)	$(0.44)	$0.79
Weighted-average limited partner units outstanding:			
Common units – basic	39,217	33,311	26,951
Common units – diluted	39,217	33,311	27,101
Subordinated units – basic and diluted	24,410	24,410	24,410

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

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

	Partners' capital Limited partners Common	Subordinated	General partner	Summit Investments' equity in contributed subsidiaries	Total
	(In thousands)				
Partners' capital, January 1, 2013	$418,856	$380,169	$20,222	$211,001	$1,030,248
Net income	22,311	20,238	1,035	9,253	52,837
Distributions to unitholders	(46,286)	(42,107)	(1,803)	—	(90,196)
Unit-based compensation	2,999	—	—	—	2,999
Consolidation of Bison Midstream net assets	—	—	—	303,168	303,168
Contribution from Summit Investments to Bison Midstream	—	—	—	2,229	2,229
Purchase of Bison Midstream	47,936	—	978	(248,914)	(200,000)
Contribution of net assets from Summit Investments 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
Consolidation of Polar Midstream net assets	—	—	—	216,105	216,105
Class B membership interest unit-based compensation	17	—	—	830	847
Repurchase of DFW Net Profits Interests	(5,859)	(5,859)	(239)	—	(11,957)
Cash advance from Summit Investments to contributed subsidiaries, net	—	—	—	72,745	72,745
Capitalized interest allocated to contributed subsidiaries from Summit Investments	—	—	—	2,046	2,046
Expenses paid by Summit Investments on behalf of contributed subsidiaries	—	—	—	11,964	11,964
Capital expenditures paid by Summit Investments on behalf of contributed subsidiaries	—	—	—	52	52
Partners' capital, December 31, 2013	$566,532	$379,287	$23,324	$523,944	$1,493,087

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SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL
(continued)

	Partners' capital Limited partners Common	Subordinated	General partner	Summit Investments' equity in contributed subsidiaries	Total
	(In thousands)				
Partners' capital, December 31, 2013	$566,532	$379,287	$23,324	$523,944	$1,493,087
Net (loss) income	(15,948)	(11,169)	3,125	9,258	(14,734)
Distributions to unitholders	(67,658)	(49,796)	(4,770)	—	(122,224)
Unit-based compensation	4,696	—	—	—	4,696
Tax withholdings on vested SMLP LTIP awards	(656)	—	—	—	(656)
Issuance of common units, net of offering costs	197,806	—	—	—	197,806
Contribution from general partner	—	—	4,235	—	4,235
Purchase of Red Rock Gathering	—	—	—	(307,941)	(307,941)
Excess of purchase price over acquired carrying value of Red Rock Gathering	(37,910)	(26,891)	(1,323)	66,124	—
Assets contributed to Red Rock Gathering from Summit Investments	2,426	1,722	85	—	4,233
Cash advance from Summit Investments to contributed subsidiaries, net	—	—	—	81,421	81,421
Expenses paid by Summit Investments on behalf of contributed subsidiaries	—	—	—	10,483	10,483
Capitalized interest allocated to contributed subsidiaries from Summit Investments	—	—	—	606	606
Capital expenditures paid by Summit Investments on behalf of contributed subsidiaries	—	—	—	597	597
Class B membership interest unit-based compensation	—	—	—	340	340
Repurchase of SMLP LTIP units	(228)	—	—	—	(228)
Partners' capital, December 31, 2014	$649,060	$293,153	$24,676	$384,832	$1,351,721

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SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL
(continued)

	Partners' capital Limited partners Common	Subordinated	General partner	Summit Investments' equity in contributed subsidiaries	Total
	(In thousands)				
Partners' capital, December 31, 2014	$649,060	$293,153	$24,676	$384,832	$1,351,721
Net (loss) income	(123,817)	(71,793)	3,398	5,403	(186,809)
Distributions to unitholders	(86,880)	(55,410)	(9,784)	—	(152,074)
Unit-based compensation	6,174	—	—	—	6,174
Tax withholdings on vested SMLP LTIP awards	(1,616)	—	—	—	(1,616)
Issuance of common units, net of offering costs	221,977	—	—	—	221,977
Contribution from general partner	—	—	4,737	—	4,737
Purchase of Polar and Divide	—	—	—	(285,677)	(285,677)
Excess of acquired carrying value over consideration paid for Polar and Divide	80,079	47,681	2,607	(130,367)	—
Cash advance from Summit Investments to contributed subsidiaries, net	—	—	—	21,719	21,719
Expenses paid by Summit Investments on behalf of contributed subsidiaries	—	—	—	3,084	3,084
Capitalized interest allocated from Summit Investments to contributed subsidiaries	—	—	—	921	921
Class B membership interest unit-based compensation	—	—	—	85	85
Partners' capital, December 31, 2015	$744,977	$213,631	$25,634	$—	$984,242

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

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

	Year ended December 31,		
	2015	2014	2013
	(In thousands)		
Cash flows from operating activities:			
Net (loss) income	$(186,809)	$(14,734)	$52,837
Adjustments to reconcile net (loss) income to net cash provided by operating activities:			
Depreciation and amortization	96,975	88,293	71,606
Amortization of deferred loan costs	3,257	2,770	2,246
Unit-based compensation	6,259	5,036	3,846
(Gain) loss on asset sales, net	(172)	442	113
Long-lived asset impairment	9,305	5,505	—
Goodwill impairment	248,851	54,199	—
Purchase accounting adjustment	—	(1,185)	—
Changes in operating assets and liabilities:			
Accounts receivable	5,180	(19,255)	(20,490)
Trade accounts payable	(2,770)	(684)	(3,419)
Due to affiliate	1,377	(883)	1,427
Change in deferred revenue	(11,453)	26,378	16,685
Ad valorem taxes payable	772	743	(11)
Accrued interest	(1,375)	6,714	12,128
Other, net	(3,447)	1,658	3,501
Net cash provided by operating activities	165,950	154,997	140,469
Cash flows from investing activities:			
Capital expenditures	(118,107)	(220,820)	(182,978)
Proceeds from asset sales	323	325	585
Acquisition of gathering systems	—	(10,872)	(210,000)
Acquisitions of gathering systems from affiliate	(288,618)	(305,000)	(200,000)
Net cash used in investing activities	(406,402)	(536,367)	(592,393)

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

	Year ended December 31,		
	2015	2014	2013
	(In thousands)		
Cash flows from financing activities:			
Distributions to unitholders	(152,074)	(122,224)	(90,196)
Borrowings under revolving credit facility	187,000	237,295	380,950
Repayments under revolving credit facility	(51,000)	(315,295)	(294,180)
Deferred loan costs	(277)	(5,320)	(10,608)
Proceeds from issuance of common units, net	221,977	197,806	—
Contribution from general partner	4,737	4,235	2,229
Cash advance from Summit Investments to contributed subsidiaries, net	21,719	81,421	72,745
Expenses paid by Summit Investments on behalf of contributed subsidiaries	3,084	10,483	11,964
Issuance of senior notes	—	300,000	300,000
Repurchase of equity-based compensation awards	—	(228)	(11,957)
Issuance of units to affiliate in connection with the Mountaineer Acquisition	—	—	100,000
Other, net	(1,807)	(656)	—
Net cash provided by financing activities	233,359	387,517	460,947
Net change in cash and cash equivalents	(7,093)	6,147	9,023
Cash and cash equivalents, beginning of period	26,504	20,357	11,334
Cash and cash equivalents, end of period	$19,411	$26,504	$20,357
Supplemental cash flow disclosures:			
Cash interest paid	$48,947	$31,524	$9,016
Less capitalized interest	3,137	3,778	6,255
Interest paid (net of capitalized interest)	$45,810	$27,746	$2,761
Cash paid for taxes	$—	$—	$660
Noncash investing and financing activities:			
Capital expenditures in trade accounts payable (period-end accruals)	$14,962	$18,076	$29,860
Excess of acquired carrying value over consideration paid for Polar and Divide	130,367	—	—
Capitalized interest allocated to contributed subsidiaries from Summit Investments	921	606	2,046
Capital expenditures paid by Summit Investments on behalf of contributed subsidiaries	—	597	52
Excess of consideration paid over acquired carrying value of Red Rock Gathering	—	(66,124)	—
Assets contributed to Red Rock Gathering from Summit Investments	—	4,233	—
Issuance of units to affiliate to partially fund the Bison Drop Down	—	—	48,914
Contribution of net assets from Summit Investments in excess of consideration paid for Bison Midstream	—	—	56,535

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

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SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
1. ORGANIZATION, BUSINESS OPERATIONS AND PRESENTATION AND CONSOLIDATION
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 the continental United States. Our business activities are conducted through our subsidiary, Summit Midstream Holdings, LLC ("Summit Holdings"), a Delaware limited liability company, and its subsidiaries. References to the "Partnership," "we," or "our," refer collectively to SMLP and its subsidiaries.
Summit Midstream GP, LLC, a Delaware limited liability company (the "general partner"), manages our operations and activities. Summit Midstream Partners, LLC, a Delaware limited liability company ("Summit Investments"), is the ultimate owner of our general partner and has the right to appoint the entire board of directors of our general partner. Summit Investments is controlled by Energy Capital Partners II, LLC and its parallel and co-investment funds (collectively, "Energy Capital Partners").
In addition to its 2% general partner interest in SMLP (including the incentive distribution rights ("IDRs") in respect of SMLP), Summit Investments has direct and indirect ownership interests in our common and subordinated units. As of December 31, 2015, Summit Investments beneficially owned 5,444,731 SMLP common units and all of our subordinated units.
Our operations are conducted through, and our operating assets are owned by, various wholly-owned operating subsidiaries. Neither SMLP nor its subsidiaries have any employees. All of the personnel that conduct our business are employed by Summit Investments, but these individuals are sometimes referred to as our employees.
Effective with the completion of its IPO, SMLP had a 100% ownership interest in Summit Holdings, which had a 100% ownership interest in both DFW Midstream Services LLC ("DFW Midstream") and Grand River Gathering, LLC ("Grand River" or the "Legacy Grand River" system).
On June 4, 2013, the Partnership acquired all of the membership interests of Bison Midstream, LLC ("Bison Midstream") from a subsidiary of Summit Investments (the "Bison Drop Down"). As such, the Bison Drop Down was determined to be a transaction among entities under common control. Prior to the Bison Drop Down, on February 15, 2013, Summit Investments acquired Bear Tracker Energy, LLC ("BTE"), which was subsequently renamed Meadowlark Midstream Company, LLC ("Meadowlark Midstream"). The net assets that comprise Bison Midstream were carved out from Meadowlark Midstream in connection with the Bison Drop Down. Common control of Bison Midstream began in February 2013.
On June 21, 2013, Mountaineer Midstream Company, LLC ("Mountaineer Midstream"), a newly formed, wholly owned subsidiary of the Partnership, acquired natural gas gathering pipeline and compression assets from an affiliate of MarkWest Energy Partners, L.P. ("MarkWest") (the "Mountaineer Acquisition"). In December 2013, Mountaineer Midstream was merged into DFW Midstream.
On March 18, 2014, SMLP acquired all of the membership interests of Red Rock Gathering Company, LLC ("Red Rock Gathering") from a subsidiary of Summit Investments (the "Red Rock Drop Down"). As such, the Red Rock Drop Down was determined to be a transaction among entities under common control. Common control of Red Rock Gathering began in October 2012. Concurrent with the closing of the Red Rock Drop Down, SMLP contributed its interest in Red Rock Gathering to Grand River.
On May 18, 2015, the Partnership acquired all of the membership interests of Polar Midstream, LLC ("Polar Midstream") and Epping Transmission Company, LLC ("Epping," and collectively with Polar Midstream, "Polar and Divide") from a subsidiary of Summit Investments (the "Polar and Divide Drop Down"). As such, the Polar and Divide Drop Down was determined to be a transaction among entities under common control. Polar Midstream's net assets were carved out of Meadowlark Midstream immediately prior to the Polar and Divide Drop Down. Concurrent with the closing of the Polar and Divide Drop Down, Epping became a wholly owned subsidiary of Polar Midstream and SMLP contributed Polar Midstream (including Epping) to Bison Midstream. Common control began in (i)

February 2013 for Polar Midstream and (ii) April 2014 for Epping.

On February 25, 2016, Summit Midstream Partners, LP ("SMLP" or the "Partnership") and Summit Midstream Partners Holdings, LLC (“SMP Holdings”) entered into a contribution agreement (the "Contribution Agreement") pursuant to which SMP Holdings agreed to contribute to the Partnership substantially all of (i) the issued and

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outstanding membership interests of Summit Midstream Utica, LLC, Meadowlark Midstream Company, LLC and Tioga Midstream, LLC (collectively, the "Contributed Entities"), each limited liability companies and indirect wholly owned subsidiaries of SMP Holdings and (ii) SMP Holdings' 40.0% joint venture interest in each of Ohio Gathering Company, L.L.C. and Ohio Condensate Company, L.L.C. (collectively with the Contributed Entities, the "2016 Drop Down Assets")(the "2016 Drop Down"). The 2016 Drop Down is expected to close in March 2016 (the "Initial Close"), subject to customary closing conditions.

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

- the Mountaineer Midstream system ("Mountaineer Midstream"), a natural gas gathering system located in the Appalachian Basin, which includes the Marcellus Shale formation in northern West Virginia;
- Bison Midstream, an associated natural gas gathering system located in the Williston Basin, which includes the Bakken and Three Forks shale formations in northwestern North Dakota;
- Polar and Divide, a crude oil and produced water gathering system and transmission pipelines located in the Williston Basin, which includes the Bakken and Three Forks shale formations in northwestern North Dakota;
- DFW Midstream, a natural gas gathering system located in the Fort Worth Basin, which includes the Barnett Shale formation in north-central Texas; and
- Grand River, a natural gas and natural gas liquids gathering and processing system located in the Piceance Basin, which includes the Mesaverde formation and the Mancos and Niobrara shale formations in western Colorado and eastern Utah.

Our operating subsidiaries, which are wholly owned by Summit Holdings, are: DFW Midstream (which includes Mountaineer Midstream); Bison Midstream (and its wholly owned subsidiaries Polar Midstream and Epping); and Grand River (and its wholly owned subsidiary Red Rock Gathering). All of our operating subsidiaries are focused on the development, construction and operation of natural gas gathering and processing systems and crude oil and produced water gathering systems.

Presentation and 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.

We conduct our operations in the midstream sector through four reportable segments:

- the Marcellus Shale, which is served by Mountaineer Midstream;
- the Williston Basin, which is served by Bison Midstream and Polar and Divide;
- the Barnett Shale, which is served by DFW Midstream; and
- the Piceance Basin, which is served by Grand River. Grand River is composed of the Legacy Grand River and Red Rock Gathering systems.

Our reportable segments reflect the way in which we internally report the financial information used to make decisions and allocate resources in connection with our operations.

The consolidated financial statements include the assets, liabilities, and results of operations of SMLP and its wholly owned subsidiaries. All intercompany transactions among the consolidated entities have been eliminated in consolidation. For the purposes of the consolidated financial statements, SMLP's results of operations reflect the results of operations of: (i) DFW Midstream and Grand River for all periods presented, (ii) Bison Midstream and Polar and Divide since February 16, 2013 and (iii) Mountaineer Midstream since June 22, 2013. The financial position, results of operations and cash flows of Bison Midstream and Polar Midstream included herein have been derived from the accounting records of Meadowlark Midstream on a carve-out basis (see Note 2). The carve-out allocations and estimates were based on methodologies that management believes are reasonable. The results

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reflected herein, however, may not reflect what Bison Midstream's or Polar Midstream's financial position, results of operations or cash flows would have been if either had been a stand-alone company.

SMLP recognized its drop down acquisitions at Summit Investments' historical cost because the acquisitions were executed by entities under common control. The excess of Summit Investments' net investment over the purchase price paid for a contributed subsidiary is recognized as an addition to partners' capital, while the excess of purchase price paid over net investment is recognized as a reduction to partners' capital. Due to the common control aspect, we account for drop down transactions on an “as-if pooled” basis for the periods during which common control existed.

Reclassifications. Certain reclassifications have been made to prior-year amounts to conform to current-year presentation. We combined the balances associated with the unfavorable gas gathering contract with other noncurrent liabilities. These balance sheet changes had no impact on (i) total liabilities or (ii) total liabilities and partners' capital. We also evaluated our historical classification of (i) gathering fee revenue associated with certain Bison Midstream percent-of-proceeds contracts and (ii) certain pass-through expenses also for Bison Midstream. As a result of this evaluation, we determined that certain amounts that had previously been recognized in cost of natural gas and NGLs would be more appropriately reflected as gathering services and related fees and other revenues to enhance reporting transparency. The impact of these reclassifications, which had no impact on net (loss) income, total partners' capital or segment adjusted EBITDA, follows.

	Year ended December 31,	
	2014	2013
	(In thousands)	
Gathering services and related fees	$15,616	$16,805
Other revenues	3,952	10,068
Net impact on total revenues	$19,568	$26,873
Cost of natural gas and NGLs	$19,568	$26,873
Net impact on cost of natural gas and NGLs and total costs and expenses	$19,568	$26,873

In the fourth quarter 2015, we began reporting all of our operations in North Dakota as one reportable segment, the Williston Basin reportable segment. These presentation changes had no impact on total assets, total liabilities, total revenues, total costs and expenses, net income, partners' capital, cash flows or total segment adjusted EBITDA. See Note 3 for additional information on this change.

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 customers and other counterparties. We evaluate the collectability of accounts receivable and the need for an allowance for doubtful accounts based on customer-specific facts and circumstances. To the extent we doubt the collectability of a specific customer or counterparty receivable, we recognize an allowance for doubtful accounts.

Other Current Assets. Other current assets primarily consist of the current portion of prepaid expenses that are charged to expense over the period of benefit or the life of the related contract.

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.

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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. Estimates of useful lives follow.

	Useful lives (In years)
Gathering and processing systems and related equipment	30
Other	4-15

Construction in progress is depreciated consistent with its applicable asset class once it is placed in service. Land and line fill are not depreciated.

We base an asset's carrying value on estimates, assumptions and judgments for useful life and salvage value. Upon sale, retirement or other disposal, 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.

Accrued capital expenditures are reflected in trade accounts payable.

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. For identified asset retirement obligations, we then evaluate whether the expected date and related costs of retirement can be estimated. We have concluded that our gathering and processing assets have an indeterminate life because they are owned and will operate for an indeterminate 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, 2015 or 2014.

Amortizing Intangibles. Upon the acquisition of DFW Midstream, certain of its 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 above-market contracts as favorable gas gathering contracts. We have recognized the below-market contract as the unfavorable gas gathering contract and included it in other noncurrent liabilities. We amortize these contracts on a units-of-production basis over the contract's estimated useful life. We define useful life as the period over which the contract is expected to contribute to our future cash flows. These contracts have original terms ranging from 10 years to 20 years. We recognize the amortization expense associated with these contracts in other revenues.

We amortize all other gas gathering contracts, or contract intangibles, over the period of economic benefit based upon 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 contracts in depreciation and amortization expense.

We have rights-of-way 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. We recognize the amortization expense associated with rights-of-way assets in depreciation and amortization expense.

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. To estimate the fair value of the reporting units under step one, we utilize two valuation methodologies: the market approach and the income approach. Both of these approaches incorporate significant estimates and assumptions to calculate enterprise fair value for a reporting unit. The most significant estimates and assumptions inherent within these two valuation methodologies are: (i) determination of the weighted-average cost of capital; (ii) the selection of guideline public companies; (iii) market multiples; (iv) weighting of the income and market approaches; (v) growth rates; (vi) commodity prices; and (vi) the expected levels of throughput volume gathered. Changes in these and other assumptions could materially affect the estimated amount of fair value for any of our reporting units.

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.

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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. Significant estimates and assumptions utilized in the determination of a reporting unit's implied fair value are based on a variety of factors specific to a given reporting unit's individual assets and liabilities as well as market and industry considerations. 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.

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 (except goodwill) 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 either a market-based approach or an income-based approach. We discuss our policy for goodwill impairment above.

Derivative Contracts. We have commodity price exposure related to our sale of the physical natural gas we retain from our DFW Midstream customers and our procurement of electricity to operate DFW Midstream's electric-drive compression assets. 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 these 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 fair-value-measurement standard under GAAP 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 the inputs 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 internally developed present value of future cash flows model that underlies management's fair value measurement).

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

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We recognize revenue earned from fee-based gathering, treating and processing services in gathering services and related fees revenue. We also earn revenue from the sale of physical natural gas purchased from our customers under percentage-of-proceeds arrangements. These revenues are recognized in natural gas, NGLs and condensate sales with corresponding expense recognition for the producer's share of the proceeds in cost of natural gas and NGLs. We sell substantially all of 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. Revenues from the retainage of natural gas and condensate are recognized in natural gas, NGLs and condensate sales; 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, with the revenue component recognized in other revenues.

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 provide gathering and/or processing 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 (i) natural gas gathering, treating, and/or processing and (ii) crude oil and/or produced water gathering.
- 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.

Certain of our gathering and processing agreements provide for a monthly, quarterly or annual minimum volume commitment ("MVC"). Under these MVCs, our customers agree to ship and/or process a minimum volume of production 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 contracted measurement 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 contracted measurement periods to the extent that such customer's throughput volumes in a subsequent contracted measurement period exceed its MVC for that contracted measurement period.

We recognize customer billings for obligations under their MVCs as revenue when the obligations are billable under the contract and the customer does not have the right to utilize shortfall payments to offset gathering or processing fees in excess of its MVCs in subsequent periods.

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 volume throughput, or (ii) expired (or lapsed) through the passage of time pursuant to the terms of the applicable gathering or processing agreement. We also recognize deferred revenue when it is determined that a given amount of MVC shortfall payments cannot be recovered by offsetting gathering or processing fees in subsequent contracted measurement periods. In making this determination, we consider both quantitative and qualitative facts and circumstances, including, but not limited to, contract terms, capacity of the associated pipeline or receipt point and/or expectations regarding future investment, drilling and production.

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.

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.

Income Taxes. As a partnership, we are generally not subject to federal and state income taxes, except as noted below. However, our unitholders are individually responsible for paying federal and state income taxes on their share of our taxable income. Net income or loss for GAAP purposes may differ significantly from taxable income reportable to our unitholders as a result of differences between the tax basis and the GAAP basis of assets and liabilities and the taxable income allocation requirements under our partnership agreement.

In general, legal entities that are chartered, organized or conducting business in the state of Texas are subject to a 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.

In 2014, we elected to apply changes to the determination of cost of goods sold for the Texas Margin Tax which permits the use of accelerated depreciation allowed for federal income tax purposes. As a result of this change, we recognized a a deferred tax liability. Other noncurrent liabilities included a deferred tax liability of $0.6 million and $1.3 million as of December 31, 2015 and 2014, respectively.

Earnings Per Unit ("EPU"). We determine basic EPU by dividing the net income or loss that is attributed, in accordance with the net income and loss allocation provisions of our partnership agreement, to common and subordinated unitholders under the two-class method, after deducting (i) the general partner's 2% interest in net income or loss, (ii) any payment of IDRs and (iii) any net income or loss of contributed subsidiaries that is attributable to Summit Investments, by the weighted-average number of common and subordinated units outstanding. Diluted EPU 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 and included in the weighted-average number of units outstanding. When it is determined that potential common units resulting from an award subject to performance or market conditions should be included in the diluted EPU calculation, the impact is reflected by applying the treasury stock method.

Comprehensive Income. Comprehensive income is the same as net income (loss) 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. 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. We accrue for losses associated with environmental remediation obligations when such losses are probable and reasonably estimable. Such accruals are adjusted as further information develops or circumstances change. Recoveries of environmental remediation costs from other parties or insurers are recorded as assets when their receipt is deemed probable.

Carve-Out Entities. For drop down transactions involving entities that were carved out of other entities, the majority of the assets and liabilities allocated to the carve-out entity are specifically identified based on the original entity's existing divisional organization. Goodwill is allocated to the carve-out entity based on initial purchase accounting estimates. Revenues and depreciation and amortization are specifically identified based on the relationship of the carve-out entity to the original entity's existing divisional structure. Operation and maintenance and general and administrative expenses are allocated to the carve-out entity based on volume throughput.

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 may materially affect our financial statements, except as noted below.

In May 2014, the FASB released a joint revenue recognition standard, Accounting Standards Update ("ASU") No. 2014-09 Revenue From Contracts With Customers (Topic 606) ("ASU 2014-09"). Under ASU 2014-09, revenue will be recognized under a five-step model: (i) identify the contract with the customer; (ii) identify the performance obligations in the contract; (iii) determine the transaction price; (iv) allocate the transaction price to performance obligations; and (v) recognize revenue when (or as) the Company satisfies a performance obligation. In its original form, ASU 2014-09 was effective for fiscal years, and interim periods within those years, beginning after December 15, 2016; early adoption was not permitted. In July 2015, the FASB reaffirmed the guidance in its April 2015 proposed ASU that defers for one year the effective date of the ASU 2014-09 for both public and nonpublic entities reporting under U.S. GAAP and allows early adoption as of the original effective date. We are currently in the process of evaluating the impact of this update.

In April 2015, the FASB issued ASU No. 2015-03 Interest—Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs ("ASU 2015-03"). Under ASU 2015-03, entities that have historically presented debt issuance costs as an asset, related to a recognized debt liability, will be required to present those costs as a direct deduction from the carrying amount of that debt liability. This presentation will result in debt issuance cost being presented the same way debt discounts have historically been handled. In August 2015, the FASB amended ASU 2015-03 to address the presentation and subsequent measurement of debt issuance costs related to line of credit (“LOC”) arrangements. The amendment added a paragraph that states that the SEC staff would not object to an entity deferring and presenting debt issuance costs as an asset and subsequently amortizing deferred debt issuance costs ratably over the term of a LOC arrangement, regardless of whether there are outstanding borrowings under that LOC arrangement. This new standard is effective for fiscal years, and interim periods within those years, beginning after December 15, 2015, and interim and annual periods thereafter. Early adoption is permitted. The adoption of this update will result in a reclassification from other noncurrent assets to long-term debt of the debt issuance costs associated with our senior notes. Debt issuance costs associated with our revolving credit facility will remain in other noncurrent assets. There will be no impact on interest expense, net income, earnings per unit or partners' capital.

In September 2015, the FASB issued ASU No. 2015-16 Business Combinations (Topic 805): Simplifying the Accounting for Measurement-Period Adjustments (“ASU 2015-16”). Under ASU 2015-16, an acquirer would be required to recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. Further, the acquirer must record in the financial statements for the same period, the effect on earnings of changes in depreciation, amortization, or other income effects, if any, as a result of the change to the provisional amounts, calculated as if the accounting had been completed at the acquisition date. Entities must also present separately on the face of the income statement or disclose in the notes the portion of the amount recorded in current-period earnings by line item that would have been recorded in previous reporting periods if the adjustment to the provisional amounts had been recognized as of the acquisition date. This new standard is effective for fiscal years, and interim periods within those years, beginning after December 15, 2015, and interim and annual periods thereafter. Early adoption is permitted. We are currently in the process of evaluating the impact of this update.

In January 2016, the FASB issued ASU No. 2016-01 Financial Instruments—Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities (“ASU 2016-01”). Among other changes, the amendments in ASU 2016-01 supersede the guidance to classify equity securities with readily determinable fair values into different categories and require equity securities to be measured at fair value with changes in the fair value recognized through net income. They also simplify the impairment assessment of equity investments without readily determinable fair values and require use of the exit price notion when measuring the fair value of financial instruments for disclosure purposes. Under ASU 2016-01, an entity will be required to present separately in other comprehensive income the portion of the total change in the fair value of a liability resulting from a change in the instrument-specific credit risk when the entity has elected to measure the liability at fair value in accordance with the fair value option for financial instruments, to separately present financial assets and financial liabilities by measurement category and form of financial asset. ASU 2016-01 also clarifies that an entity should evaluate the need for a valuation allowance on a deferred tax asset related to available-for-sale securities in combination with the entity’s other deferred tax assets. This new standard is effective for fiscal years, and interim periods within those years, beginning after December 31, 2017. Early adoption is permissible, but limited in application. The adoption of this new update could impact the fair value we disclose for certain financial instruments but is not expected to impact amounts recognized in the consolidated financial statements.

3. SEGMENT INFORMATION

As of December 31, 2015, our reportable segments are:

- the Marcellus Shale, which is served by Mountaineer Midstream;
- the Williston Basin, which is served by Bison Midstream and Polar and Divide;
- the Barnett Shale, which is served by DFW Midstream; and
- the Piceance Basin, which is served by Grand River.

Each of our reportable segments provides midstream services in a specific geographic area. Our reportable segments reflect the way in which we internally report the financial information used to make decisions and allocate resources in connection with our operations.

In connection with the Polar and Divide Drop Down, we identified two reportable segments in the Williston Basin. For the second and third quarters of 2015, we reported the results of Bison Midstream in the Williston Basin – Gas reportable segment and those of Polar and Divide in the Williston Basin – Liquids reportable segment. In the fourth quarter of 2015, we changed how we manage and evaluate our operations in North Dakota. Prior to the fourth quarter of 2015, Bison Midstream and Polar and Divide were managed separately and their financial results were evaluated separately. In the fourth quarter of 2015, we began managing our North Dakota operations under a single management team and began reporting their financial results on a combined basis. As a result, we no longer distinguish between liquids and gas in the Williston Basin and now have one reportable segment, the Williston Basin reportable segment, representing those operations.

Corporate represents those assets and liabilities and revenues and expenses that are not specifically attributable to a reportable segment, not individually reportable, or that have not been allocated to our reportable segments. Beginning in the first quarter of 2015, we discontinued allocating certain general and administrative expenses, primarily salaries, benefits, incentive compensation and rent expense, to our operating segments.

Assets by reportable segment follow.

	December 31,		
	2015	2014	2013
	(In thousands)		
Assets:			
Marcellus Shale	$233,116	$243,884	$214,379
Williston Basin	563,952	709,888	645,014
Barnett Shale	416,586	428,935	431,578
Piceance Basin	797,057	872,437	876,969
Total reportable segment assets	2,010,711	2,255,144	2,167,940
Corporate	29,820	38,577	23,203
Total assets	$2,040,531	$2,293,721	$2,191,143

For information on the sale or impairment of long-lived assets, other than goodwill, see Note 4. For information on goodwill by reportable segment, including goodwill impairments, see Note 6.

Revenues by reportable segment follow.

	Year ended December 31,		
	2015	2014	2013
	(In thousands)		
Revenues:			
Marcellus Shale	$28,468	$22,694	$9,588
Williston Basin	85,887	104,471	81,501
Barnett Shale	88,042	93,001	105,324
Piceance Basin	168,922	152,537	127,273
Total reportable segment revenues and total revenues	$371,319	$372,703	$323,686

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

	Year ended December 31,					
	2015		2014		2013	
Percentage of total revenues (1):						
Counterparty A - Piceance	17	%	19	%	19	%
Counterparty B - Piceance	16	%	*		*	
Counterparty C - Barnett Shale	*		*		14	%

(1) Includes recognition of revenue that was previously deferred in connection with minimum volume commitments (see Notes 2 and 7).

* Less than 10%

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Depreciation and amortization, including the amortization expense associated with our favorable and unfavorable gas gathering contracts as reported in other revenues, by reportable segment follows.

	Year ended December 31,		
	2015	2014	2013
	(In thousands)		
Depreciation and amortization:			
Marcellus Shale	$8,682	$7,648	$3,998
Williston Basin	26,280	22,491	16,669
Barnett Shale	16,392	16,601	14,961
Piceance Basin	45,018	40,965	35,527
Total reportable segment depreciation and amortization	96,372	87,705	71,155
Corporate	603	588	451
Total depreciation and amortization	$96,975	$88,293	$71,606

Capital expenditures by reportable segment follow.

	Year ended December 31,		
	2015	2014	2013
	(In thousands)		
Capital expenditures:			
Marcellus Shale	$1,306	$33,866	$1,822
Williston Basin	90,234	139,422	99,983
Barnett Shale	6,875	14,567	29,534
Piceance Basin	19,263	32,505	50,709
Total reportable segment capital expenditures	117,678	220,360	182,048
Corporate	429	460	930
Total capital expenditures	$118,107	$220,820	$182,978

We assess the performance of our reportable segments based on segment adjusted EBITDA. We define segment adjusted EBITDA as total revenues less total costs and expenses; plus (i) other income excluding interest income, (ii) depreciation and amortization, (iii) adjustments related to MVC shortfall payments, (iv) impairments and (v) other noncash expenses or losses, less other noncash income or gains.

Segment adjusted EBITDA by reportable segment follows.

	Year ended December 31,		
	2015	2014	2013
	(In thousands)		
Reportable segment adjusted EBITDA:			
Marcellus Shale	$23,214	$15,940	$6,333
Williston Basin	47,010	31,551	17,350
Barnett Shale	59,526	60,528	69,473
Piceance Basin	104,467	107,953	80,941
Total reportable segment adjusted EBITDA	$234,217	$215,972	$174,097

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A reconciliation of (loss) income before income taxes to total reportable segment adjusted EBITDA follows.

	Year ended December 31,		
	2015	2014	2013
	(In thousands)		
Reconciliation of Income (loss) Before Income Taxes to Segment Adjusted EBITDA:			
(Loss) income before income taxes	$(187,485)	$(14,103)	$53,566
Add:			
Allocated corporate expenses	23,772	11,065	8,773
Interest expense	48,616	40,159	19,173
Depreciation and amortization	96,975	88,293	71,606
Adjustments related to MVC shortfall payments	(11,902)	26,565	17,025
Unit-based compensation	6,259	5,036	3,846
Loss on asset sales	42	442	113
Long-lived asset impairment	9,305	5,505	—
Goodwill impairment	248,851	54,199	—
Less:			
Interest income	2	4	5
Gain on asset sales	214	—	—
Impact of purchase price adjustment	—	1,185	—
Total reportable segment adjusted EBITDA	$234,217	$215,972	$174,097

Segment adjusted EBITDA excludes the effect of allocated corporate expenses, such as certain general and administrative expenses (including compensation-related expenses and professional services fees), transaction costs, interest expense and income tax expense.

Adjustments related to MVC shortfall payments account for:

- the net increases or decreases in deferred revenue for MVC shortfall payments and
- our inclusion of expected annual MVC shortfall payments. We include a proportional amount of these historical or expected MVC shortfall payments in each quarter prior to the quarter in which we actually recognize the shortfall payment. These adjustments have not been billed to our customers and are not recognized in our consolidated financial statements.

Adjustments related to MVC shortfall payments by reportable segment follow.

	Year ended December 31,		
	2015	2014	2013
	(In thousands)		
Adjustments related to MVC shortfall payments:			
Williston Basin	$11,870	$10,743	$3,600
Barnett Shale	(2,182)	628	1,030
Piceance Basin	(21,590)	15,194	12,395
Total adjustments related to MVC shortfall payments	$(11,902)	$26,565	$17,025

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4. PROPERTY, PLANT, AND EQUIPMENT, NET

Details on property, plant, and equipment follow.

	December 31,	
	2015	2014
	(In thousands)	
Gathering and processing systems and related equipment	$1,574,916	$1,459,585
Construction in progress	25,484	37,604
Land and line fill	9,339	9,964
Other	30,935	28,871
Total	1,640,674	1,536,024
Less accumulated depreciation	176,872	121,674
Property, plant, and equipment, net	$1,463,802	$1,414,350

During 2015 and 2014, we identified certain events, facts and circumstances which indicated that certain of our property, plant and equipment could be impaired. (There were no impairment indicators during 2013.) As such, we reviewed the assets that had been identified as potentially impaired and estimated the fair value of the identified property, plant and equipment using a market-based approach. For the assets which had fair values below their carrying value, we recognized the following long-lived asset impairments, by segment.

	Year ended December 31,		
	2015	2014	2013
	(In thousands)		
Long-lived asset impairment:			
Williston Basin	$7,554	$—	$—
Barnett Shale	531	5,505	—
Piceance Basin	1,220	—	—

Our impairment determinations, in the context of these reviews, involved significant assumptions and judgments. Differing assumptions regarding any of these inputs could have a significant effect on the various valuations. As such, the fair value measurements utilized within these estimates are classified as non-recurring Level 3 measurements in the fair value hierarchy because they are not observable from objective sources. Due to the volatility of the inputs used, we cannot predict the likelihood of any future impairment.

During the fourth quarters of 2015 and 2014, we identified a need to evaluate the goodwill associated with certain of our gathering systems (see Note 6). In connection with these evaluations, we also evaluated the related property, plant and equipment associated therewith for impairment and concluded that no impairment was necessary.

Depreciation expense and capitalized interest follow.

	Year ended December 31,		
	2015	2014	2013
	(In thousands)		
Depreciation expense	$55,685	$49,816	$37,313
Capitalized interest	3,137	3,778	6,255

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5. AMORTIZING INTANGIBLE ASSETS AND UNFAVORABLE GAS GATHERING CONTRACT

Details regarding our intangible assets and the unfavorable gas gathering contract (included in other noncurrent liabilities), all of which are subject to amortization, follow.

	December 31, 2015			
	Useful lives (In years)	Gross carrying amount	Accumulated amortization	Net
		(Dollars in thousands)		
Favorable gas gathering contracts	18.7	$24,195	$(9,534)	$14,661
Contract intangibles	12.5	426,464	(111,052)	315,412
Rights-of-way	25.2	125,922	(17,902)	108,020
Total intangible assets		$576,581	$(138,488)	$438,093
Unfavorable gas gathering contract	10.0	$10,962	$(6,077)	$4,885

	December 31, 2014			
	Useful lives (In years)	Gross carrying amount	Accumulated amortization	Net
		(Dollars in thousands)		
Favorable gas gathering contracts	18.7	$24,195	$(8,056)	$16,139
Contract intangibles	12.5	426,464	(75,713)	350,751
Rights-of-way	24.7	123,581	(12,737)	110,844
Total intangible assets		$574,240	$(96,506)	$477,734
Unfavorable gas gathering contract	10.0	$10,962	$(5,385)	$5,577

During the fourth quarters of 2015 and 2014, we identified a need to evaluate the goodwill associated with certain of our gathering systems (see Note 6). In connection with these evaluations, we also evaluated the related intangible assets associated therewith for impairment and concluded that no impairment was necessary.

We recognized amortization expense in other revenues as follows:

	Year ended December 31,		
	2015	2014	2013
	(In thousands)		
Amortization expense – favorable gas gathering contracts	$(1,478)	$(1,741)	$(2,078)
Amortization expense – unfavorable gas gathering contract	692	797	1,046

We recognized amortization expense in costs and expenses as follows:

	Year ended December 31,		
	2015	2014	2013
	(In thousands)		
Amortization expense – contract intangibles	$35,339	$32,554	$28,654
Amortization expense – rights-of-way	5,165	4,979	4,607

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The estimated aggregate annual amortization expected to be recognized as of December 31, 2015 for each of the five succeeding fiscal years follows.

	Intangible assets	Unfavorable gas gathering contract
	(In thousands)	
2016	$42,301	$924
2017	41,152	1,047
2018	40,606	1,035
2019	40,852	1,045
2020	43,498	834

6. GOODWILL

Recorded goodwill is related to the original acquisitions of the Grand River, Bison Midstream, Polar and Divide and Mountaineer Midstream systems. The assets acquired in the Polar and Divide Drop Down were carved out of Meadowlark Midstream. As such, we elected to apply the historical cost approach to determine the amount of goodwill to assign to the Polar and Divide reporting unit. Our procedures indicated that the remaining goodwill balance at Meadowlark Midstream was entirely attributable to the Polar and Divide reporting unit.

A rollforward of goodwill by reportable segment and in total follows.

	Piceance Basin	Williston Basin	Marcellus Shale	Total
	(In thousands)			
Goodwill, January 1, 2014	$45,478	$257,572	$16,211	$319,261
Goodwill impairment	—	(54,199)	—	(54,199)
Goodwill, December 31, 2014	45,478	203,373	16,211	265,062
Goodwill impairment	(45,478)	(203,373)	—	(248,851)
Goodwill, December 31, 2015	$—	$—	$16,211	$16,211

Accumulated goodwill impairments by reportable segment for those reporting units that have previously recognized goodwill follow.

	December 31, 2015	2014	2013
	(In thousands)		
Accumulated goodwill impairment:			
Piceance Basin	$45,478	$—	$—
Williston Basin	257,572	54,199	—
Total accumulated goodwill impairment	$303,050	$54,199	$—

As discussed in Note 2, we evaluate goodwill for impairment annually on September 30 and 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 value, including goodwill.

2014 Annual Impairment Evaluation. In September 2014, we performed our annual goodwill impairment testing as of September 30 using a combination of the income and market approaches. We determined that the fair value of the Grand River, Mountaineer Midstream and Polar Midstream reporting units substantially exceeded their carrying value, including goodwill. We also determined that the fair value of the Bison Midstream reporting unit exceeded its carrying value. However, it did not exceed its carrying value, including goodwill, by a substantial amount. Because the fair value of each reporting unit exceeded its carrying value, including goodwill, there were no associated impairments of goodwill in connection with our 2014 annual goodwill impairment test.

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Fourth Quarter 2014 Goodwill Impairment. During the latter part of the fourth quarter of 2014, the declines in prices for natural gas, NGLs and crude oil accelerated, negatively impacting producers in each of our areas of operation. As a result, we considered whether the goodwill associated with our Grand River, Mountaineer Midstream, Polar Midstream and Bison Midstream reporting units could have been impaired. Our assessments related to Grand River and Mountaineer Midstream did not result in an indication that the associated goodwill had been impaired.

Our assessment related to the Polar Midstream and Bison Midstream reporting units did result in an indication that the associated goodwill could have been impaired. We noted that both reporting units were impacted by the recent price declines. We also noted that a key Bison Midstream customer announced that it was delaying its previously announced drilling plans which caused SMLP to reduce its forecasted volume assumption. The impact of these events increased the likelihood that the goodwill associated with the Polar Midstream and Bison Midstream reporting units could have been impaired. As such, we concluded that a triggering event occurred during the fourth quarter of 2014 requiring that we test the goodwill associated with these reporting units for impairment.

In connection therewith, we reperformed our step one analyses for each as of December 31, 2014. To estimate the fair value of the reporting units, we utilized two valuation methodologies: the market approach and the income approach. The results of our step one goodwill impairment testing indicated that the fair value of the Polar Midstream reporting unit exceeded its carrying value, including goodwill as of December 31, 2014. As a result, there was no associated impairment of goodwill in connection with the fourth quarter 2014 triggering event.

The results of our step one goodwill impairment testing indicated that the fair value of the Bison Midstream reporting unit was below its carrying value, including goodwill as of December 31, 2014. As a result, we performed step two of the goodwill impairment test.

To perform step two, we first determined the fair values of the identifiable assets and liabilities. Significant assumptions utilized in the determination of the fair value of each reporting unit's individual assets and liabilities included the determination of discount rate and contributory asset charge utilized in our calculation of the fair value of our contract intangibles, expected levels of throughput volume and associated capital expenditures and commodity prices.

In the first quarter of 2015, we finalized our calculations of the fair values of the identified assets and liabilities in step two of the December 31, 2014 goodwill impairment testing for the Bison Midstream reporting unit. This process confirmed the preliminary goodwill impairment of $54.2 million that was recognized as of December 31, 2014.

2015 Annual Impairment Evaluation. We performed our annual goodwill impairment testing as of September 30, 2015 using a combination of the income and market approaches. We determined that the fair value of the Grand River, Mountaineer Midstream and Polar Midstream reporting units exceeded their carrying value, including goodwill. Because the fair value of each reporting unit exceeded its carrying value, including goodwill, there were no associated impairments of goodwill in connection with our 2015 annual goodwill impairment test.

Fourth Quarter 2015 Goodwill Impairments. During the latter part of the fourth quarter of 2015 and the early part of the first quarter of 2016, the declines in forward prices for natural gas, NGLs and crude oil accelerated significantly. As a result, the energy sector's public debt and equity market experienced increased volatility, particularly for comparable companies operating in the midstream services sector. Additionally, during this period, the values of our publicly traded equity and debt instruments decreased as did those of comparable midstream companies.

Due to (i) the increased market volatility, (ii) the decrease in market values of comparable companies, (iii) the continued trend of falling commodity prices and (iv) the finalization of our annual financial and operating plans which took into account changes resulting from expected levels of drilling activity, we concluded that a triggering event occurred during the fourth quarter of 2015 requiring that we test the goodwill associated with our Grand River and Polar and Divide reporting units. Our assessment related to Mountaineer Midstream did not result in an indication that a triggering event had occurred for Mountaineer Midstream.

In connection therewith, we updated our step one analyses as of December 31, 2015. These updated analyses indicated that the carrying values for Grand River and Polar and Divide exceeded their estimated fair values. As a result, we then performed step two of the goodwill impairment test for both reporting units.

To perform step two, we first determined the estimated fair values of the identifiable assets and liabilities. Significant assumptions utilized in the determination of the fair value of each reporting unit's individual assets and liabilities included the determination of discount rate taking into consideration company-specific risks and contributory asset charge utilized in our contract intangibles, expected levels of throughput volume and associated capital expenditures.

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Our preliminary estimates of the fair values of the identified assets and liabilities calculated in step two indicated that all of the associated goodwill for both reporting units had been impaired. As such, we recorded an estimated goodwill impairment of $45.5 million for Grand River and $203.4 million for Polar and Divide. These amounts represent our estimate of impairment pending finalization of the fair value calculations. We expect finalization to occur in the first quarter of 2016.

Fair Value Measurement. Our impairment determinations, in the context of (i) our annual impairment evaluations and (ii) our other-than-annual impairment evaluations involved significant assumptions and judgments, as discussed above. Differing assumptions regarding any of these inputs could have a significant effect on the various valuations. As such, the fair value measurements utilized within these models are classified as non-recurring Level 3 measurements in the fair value hierarchy because they are not observable from objective sources. Due to the volatility of the inputs used, we cannot predict the likelihood of any future impairment.

7. DEFERRED REVENUE

The majority of our gas gathering agreements provide for a monthly, quarterly or annual MVC from our customers. 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.

Many of our gas gathering agreements contain provisions that can reduce or delay the cash flows that we expect to receive from our MVCs to the extent that a customer's actual throughput volumes are above or below its MVC for the applicable contracted measurement period. 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 that customer's 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 measurement periods (as applicable).
- To the extent that a customer's throughput volumes exceed its MVC in the applicable contracted measurement period, it may be entitled to apply the excess throughput against its aggregate MVC, thereby reducing the period for which its annual MVC applies. As a result of this mechanism, the weighted-average remaining period for which our MVCs apply will be 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.

A rollforward of current deferred revenue follows.

	Williston Basin	Barnett Shale	Piceance Basin	Total current
	(In thousands)			
Current deferred revenue, January 1, 2014	$—	$1,555	$—	$1,555
Additions	—	2,610	—	2,610
Less revenue recognized	—	1,788	—	1,788
Current deferred revenue, December 31, 2014	—	2,377	—	2,377
Additions	—	677	2,743	3,420
Less revenue recognized	—	2,377	2,743	5,120
Current deferred revenue, December 31, 2015	$—	$677	$—	$677

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A rollforward of noncurrent deferred revenue follows.

	Williston Basin	Barnett Shale	Piceance Basin	Total noncurrent
	(In thousands)			
Noncurrent deferred revenue, January 1, 2014	$6,389	$—	$23,294	$29,683
Additions	10,743	—	14,813	25,556
Noncurrent deferred revenue, December 31, 2014	17,132	—	38,107	55,239
Additions	11,897	—	12,765	24,662
Less revenue recognized	27	—	34,388	34,415
Noncurrent deferred revenue, December 31, 2015	$29,002	$—	$16,484	$45,486

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

In September 2015, we determined that it would be remote for a certain Piceance Basin customer to ship volumes in excess of its MVC such that it could recover certain previous MVC shortfall payments, which had been recorded as deferred revenue, as an offset to future gathering fees. We based this determination on public statements by the customer regarding future drilling and investment plans in the area covered by the MVC contract. Due to the remote nature of having to perform any services associated with the previously deferred gathering revenue, we evaluated (i) the terms of the customer contract, (ii) the capacity of the central receipt points for throughput volumes covered by the MVC contract and (iii) the size of the area of mutual interest ("AMI"), including the number of drilling locations to determine what amount of previously deferred gathering revenue had met the criteria for revenue recognition. Our evaluation resulted in the recognition of $34.4 million of gathering services and related fees revenue that had been previously deferred with a corresponding reduction to deferred revenue. This represents recognition of amounts deferred up to the September 2015 event triggering the conclusion that the associated shortfall payments should be recognized as revenue.

As of December 31, 2015, accounts receivable included $12.7 million of shortfall billings related to MVC arrangements that can be utilized to offset gathering fees in subsequent periods.

8. DEBT

Debt consisted of the following:

	December 31, 2015	2014
	(In thousands)	
Summit Holdings variable rate senior secured revolving credit facility (2.93% at December 31, 2015 and 2.67% at December 31, 2014) due November 2018	$344,000	$208,000
Summit Holdings 5.50% Senior unsecured notes due August 2022	300,000	300,000
Summit Holdings 7.50% Senior unsecured notes due July 2021	300,000	300,000
Total long-term debt	$944,000	$808,000

The aggregate amount of our debt maturities during each of the years after December 31, 2015 are as follows:

	Debt
	(In thousands)
2016	$—
2017	—
2018	344,000
2019	—
2020	—
Thereafter	600,000
Total long-term debt	$944,000

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Revolving Credit Facility. We have a senior secured revolving credit facility which allows for revolving loans, letters of credit and swingline loans (the "revolving credit facility"). The revolving credit facility has a $700.0 million borrowing capacity, matures in November 2018, and includes a $200.0 million accordion feature. It 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.

Borrowings under the revolving credit facility bear interest at the London Interbank Offered Rate ("LIBOR") or an Alternate Base Rate ("ABR") plus an applicable margin ranging from 0.75% to 1.75% for ABR borrowings and 1.75% to 2.75% for LIBOR borrowings, with the commitment fee ranging from 0.30% to 0.50% in each case based on our relative leverage at the time of determination. At December 31, 2015, the applicable margin under LIBOR borrowings was 2.50%, the interest rate was 2.93% and the unused portion of the revolving credit facility totaled $356.0 million (subject to a commitment fee of 0.50%).

The revolving credit agreement contains affirmative and negative covenants customary for credit facilities of its size and nature that, among other things, limit or restrict the ability to: (i) incur additional debt; (ii) make investments; (iii) engage in certain mergers, consolidations, acquisitions or sales of assets; (iv) enter into swap agreements and power purchase agreements; (v) enter into leases that would cumulatively obligate payments in excess of $30.0 million over any 12-month period; and (vi) prohibits the payment of distributions by Summit Holdings if a default then exists or would result therefrom, and otherwise limits the amount of distributions Summit Holdings can make. In addition, the revolving credit facility requires Summit Holdings to maintain a ratio of consolidated trailing 12-month earnings before interest, income taxes, depreciation and amortization ("EBITDA," as defined in the credit agreement) 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. Additionally, the total leverage ratio upper limit can be increased from 5.0 to 1.0 to 5.5 to 1.0 at our option, subject to the inclusion of a senior secured leverage ratio (senior secured net indebtedness to consolidated trailing 12-month EBITDA, as defined in the credit agreement) upper limit of 3.75 to 1.0.

On February 25, 2016, we closed on an amendment to our revolving credit facility, which will become effective contingent upon and concurrent with the Initial Close of the 2016 Drop Down (the "Contingent Amendment"). In connection with the Contingent Amendment, we have received commitments to (i) increase the revolving credit facility's borrowing capacity from $700.0 million to $1.25 billion, (ii) include a new investment basket allowing the Co-Issuers (as defined below) to buy back up to $100.0 million of our outstanding senior unsecured notes and (iii) approve various amendments to facilitate the 2016 Drop Down. There will be no change to the pricing or the maturity date of the revolving credit facility in connection with the Contingent Amendment.

As of December 31, 2015, we were in compliance with the revolving credit facility's covenants. There were no defaults or events of default during the year ended December 31, 2015.

Senior Notes. In July 2014, Summit Holdings and its 100% owned finance subsidiary, Summit Midstream Finance Corp. ("Finance Corp.," together with Summit Holdings, the "Co-Issuers"), co-issued $300.0 million of 5.50% senior unsecured notes maturing August 15, 2022 (the "5.5% senior notes"). In June 2013, the Co-Issuers co-issued $300.0 million of 7.50% senior unsecured notes maturing July 1, 2021 (the "7.5% 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 5.5% senior notes and the 7.5% 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, the 5.5% senior notes and the 7.5% 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 5.5% senior notes and the 7.5% 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.

5.5% Senior Notes. We will pay interest on the 5.5% senior notes semi-annually in cash in arrears on February 15 and August 15 of each year, commencing February 15, 2015. The 5.5% senior notes are senior, unsecured obligations and rank equally in right of payment with all of our existing and future senior obligations. The 5.5% 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 5.5% senior notes to repay a portion of the balance outstanding under our revolving credit facility.

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At any time prior to August 15, 2017, the Co-Issuers may redeem up to 35% of the aggregate principal amount of the 5.5% senior notes at a redemption price of 105.500% of the principal amount of the 5.5% 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 August 15, 2017, the Co-Issuers may redeem all or part of the 5.5% senior notes at a redemption price of 104.125% (with the redemption premium declining ratably each year to 100.000% on and after August 15, 2020), plus accrued and unpaid interest, if any. Debt issuance costs of $5.1 million, recognized in other noncurrent assets, are being amortized over the life of the senior notes.

The 5.5% senior notes' 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 5.5% senior notes' 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 5.5% senior notes; (ii) default in the payment when due of the principal of, or premium, if any, on the 5.5% senior notes; (iii) failure by the Co-Issuers or SMLP to comply with certain covenants relating to mergers and consolidations, 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 5.5% 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 5.5% senior notes may declare all the 5.5% senior notes to be due and payable immediately.

As of December 31, 2015, we were in compliance with the covenants of the 5.5% senior notes and there were no defaults or events of default during the year ended December 31, 2015.

7.5% Senior Notes. The 7.5% 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.

We pay interest on the 7.5% senior notes semi-annually in cash in arrears on January 1 and July 1 of each year. The 7.5% senior notes are senior, unsecured obligations and rank equally in right of payment with all of our existing and future senior obligations. The 7.5% 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 7.5% senior notes to repay a portion of the balance outstanding under our revolving credit facility.

Effective as of April 7, 2014, all of the holders of our 7.5% senior notes exchanged their unregistered senior notes and the guarantees of those notes for registered notes and guarantees. 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.

At any time prior to July 1, 2016, the Co-Issuers may redeem up to 35% of the aggregate principal amount of the 7.5% senior notes at a redemption price of 107.500% of the principal amount of the 7.5% 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 7.5% senior notes at a redemption price of 105.625% (with the redemption premium declining ratably each year to 100.000% on and after July 1, 2019), plus accrued and unpaid interest, if any. Debt issuance costs of $7.4 million, recognized in other noncurrent assets, are being amortized over the life of the senior notes.

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The 7.5% senior notes 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 7.5% senior notes 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 7.5% senior notes; (ii) default in the payment when due of the principal of, or premium, if any, on the 7.5% senior notes; (iii) failure by the Co-Issuers or SMLP to comply with certain covenants relating to mergers and consolidations, 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 7.5% 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 7.5% 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 7.5% senior notes may declare all the 7.5% senior notes to be due and payable immediately.

As of December 31, 2015, we were in compliance with the covenants for the 7.5% senior notes and there were no defaults or events of default during the year ended December 31, 2015.

9. FINANCIAL INSTRUMENTS

Concentrations of Credit 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 frequently 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 primarily comprise amounts due for the gathering, treating and processing services we provide to our customers and also the sale of natural gas liquids resulting from our processing services. 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 can require letters of credit for receivables from counterparties that are judged to have substandard credit, unless the credit risk can otherwise be mitigated. Our top five customers or counterparties accounted for 70% of total accounts receivable at December 31, 2015, compared with 62% as of December 31, 2014.

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

A summary of the estimated fair value of our debt financial instruments follows.

	December 31, 2015		December 31, 2014	
	Carrying value	Estimated fair value (Level 2)	Carrying value	Estimated fair value (Level 2)
	(In thousands)			

Revolving credit facility	$344,000	$344,000	$208,000	$208,000
5.5% Senior notes	300,000	224,000	300,000	281,750
7.5% Senior notes	300,000	257,000	300,000	306,750

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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, 2015 and December 31, 2014. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value of the senior notes.

10. PARTNERS' CAPITAL

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, 2013	24,412,427	24,409,850	996,320	49,818,597
Units issued to a subsidiary of Summit Investments in connection with the Bison Drop Down	1,553,849	—	31,711	1,585,560
Units issued to a subsidiary of Summit Investments in connection with the Mountaineer Acquisition	3,107,698	—	63,422	3,171,120
Net units issued under SMLP LTIP	5,892	—	—	5,892
Units, January 1, 2014	29,079,866	24,409,850	1,091,453	54,581,169
Units issued in connection with the March Equity 2014 Offering	5,300,000	—	108,337	5,408,337
Net units issued under SMLP LTIP	46,647	—	861	47,508
Units, December 31, 2014	34,426,513	24,409,850	1,200,651	60,037,014
Units issued in connection with the May 2015 Equity Offering	7,475,000	—	152,551	7,627,551
Net units issued under SMLP LTIP	161,131	—	1,498	162,629
Units, December 31, 2015	42,062,644	24,409,850	1,354,700	67,827,194

Unit Offerings. In March 2014, we completed an underwritten public offering of 10,350,000 common units at a price of $38.75 per unit, of which 5,300,000 common units were offered by the Partnership and 5,050,000 common units were offered by a subsidiary of Summit Investments, pursuant to an effective shelf registration statement on Form S-3 previously filed with the SEC. Concurrently, our general partner made a capital contribution to maintain its 2% general partner interest in SMLP. We used the proceeds from the primary offering and the general partner capital contribution to fund a portion of the purchase of Red Rock Gathering.

In September 2014, a subsidiary of Summit Investments completed an underwritten public offering of 4,347,826 SMLP common units pursuant to an effective shelf registration statement on Form S-3 previously filed with the SEC. We did not receive any proceeds from this offering.

In May 2015, we completed an underwritten public offering of 6,500,000 common units at a price of $30.75 per unit pursuant to an effective shelf registration statement on Form S-3 previously filed with the SEC (the "May 2015 Equity Offering"). On May 22, 2015, the underwriters exercised in full their option to purchase an additional 975,000 common units from us at a price of $30.75 per unit. Concurrent with both transactions, our general partner made a capital contribution to us to maintain its 2% general partner interest.

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 ("MQD," as defined below) plus any arrearages in the payment of the MQD from prior quarters. The subordination period ends on the first business day after we have earned and paid at least $1.60 (the MQD 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. The subordination period ended in conjunction with the February 2016 distribution payment in respect of the fourth quarter of 2015 and the then-outstanding subordinated units converted to common units on a one-for-one basis.

Summit Investments' Equity in Contributed Subsidiaries. Summit Investments' equity in contributed subsidiaries represents its position in the net assets of Polar and Divide, Red Rock Gathering and Bison Midstream that have been acquired by SMLP. The balance also reflects net income attributable to Summit Investments for

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Polar and Divide, 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. During the years ended December 31, 2015, 2014 and 2013, net income was attributed to Summit Investments for:

- Polar and Divide for the period from February 16, 2013 to May 18, 2015;
- Red Rock Gathering for the period from January 1, 2013 to March 18, 2014; and
- Bison Midstream for the period from February 16, 2013 to June 4, 2013.

Although included in partners' capital, any net income attributable to Summit Investments is excluded from the calculation of EPU.

Polar and Divide Drop Down. On May 18, 2015, we acquired 100% of the membership interests in Polar Midstream and Epping from a subsidiary of Summit Investments. We paid total net cash consideration of $285.7 million in exchange for Summit Investments' $416.0 million net investment in Polar Midstream and Epping, including customary working capital and capital expenditures adjustments (see Note 15 for additional information). We recognized a capital contribution from Summit Investments for the difference between cash consideration paid and Summit Investments' net investment in Polar Midstream and Epping.

The calculation of the capital contribution and its allocation to partners' capital follow (dollars in thousands).

Summit Investments' net investment in Polar Midstream and Epping		$416,044
Total net cash consideration paid to a subsidiary of Summit Investments		285,677
Excess of acquired carrying value over consideration paid		$130,367
Allocation of capital contribution:		
General partner interest	$2,607	
Common limited partner interest	80,079	
Subordinated limited partner interest	47,681	
Partners' capital contribution – excess of acquired carrying value over consideration paid		$130,367

Red Rock Drop Down. On March 18, 2014, we acquired 100% of the membership interests in Red Rock Gathering from a subsidiary of Summit Investments. We paid total net cash consideration of $307.9 million (including working capital adjustments accrued in December 2014 and cash settled in February 2015) in exchange for Summit Investments' $241.8 million net investment in Red Rock Gathering. As a result of the excess of the purchase price over acquired carrying value of Red Rock Gathering, SMLP recognized a capital distribution to Summit Investments.

The calculation of the capital distribution and its allocation to partners' capital follow (dollars in thousands).

Summit Investments' net investment in Red Rock Gathering		$241,817
Total net cash consideration paid to a subsidiary of Summit Investments		307,941
Excess of consideration paid over acquired carrying value		$(66,124)
Allocation of capital distribution:		
General partner interest	$(1,323)	
Common limited partner interest	(37,910)	
Subordinated limited partner interest	(26,891)	
Partners' capital distribution – excess of consideration paid over acquired carrying value		$(66,124)

Bison Drop Down. On June 4, 2013, a subsidiary of Summit Investments entered into a purchase and sale agreement with SMLP whereby SMLP acquired the Bison Gas Gathering system. In exchange for its $305.4 million net investment in Bison Midstream, SMLP paid Summit Investments 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 Summit Investments.

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The calculation of the capital contribution and its allocation to partners' capital follow (dollars in thousands).

Summit Investments' net investment in Bison Midstream		$305,449
Aggregate cash paid to Summit Investments	$200,000	
Issuance of 1,553,849 SMLP common units to Summit Investments	47,936	
Issuance of 31,711 SMLP general partner units to the general partner	978	
Total consideration paid to a subsidiary of Summit Investments		248,914
Excess of acquired carrying value over consideration paid		$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 contribution – excess of acquired carrying value over consideration paid		$56,535

The number of units issued to Summit Investments 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 Summit Investments. 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 Summit Investments after giving effect to the general partner allocation.

Mountaineer Acquisition. We completed the acquisition of Mountaineer Midstream on June 21, 2013. The purchase price of $210.0 million was funded with $110.0 million of borrowings under SMLP's revolving credit facility and the issuance for cash of $100.0 million of SMLP common units and general partner interests to a subsidiary of Summit Investments and the general partner.

The allocation and valuation of units issued to partially fund the Mountaineer Acquisition follow (dollars in thousands).

Issuance of 3,107,698 SMLP common units to Summit Investments	$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 Summit Investments 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.

Cash Distribution Policy

Our cash distribution policy, as expressed in our partnership agreement, may not be modified or repealed without amending our partnership agreement. 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 MQD stated in our partnership agreement.

General Partner Interest. 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.

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

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and the payment of costs and expenses, including reimbursements of expenses to our general partner. The amount of distributions paid under our policy is subject to fluctuations based on the amount of cash we generate from our business 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.

Cash Distributions Paid and Declared. We paid the following per-unit distributions during the years ended December 31:

	Year ended December 31,		
	2015	2014	2013
Per-unit annual distributions to unitholders	$2.270	$2.040	$1.725

On January 21, 2016, the board of directors of our general partner declared a distribution of $0.575 per unit for the quarterly period ended December 31, 2015. This distribution, which totaled $41.0 million, was paid on February 12, 2016 to unitholders of record at the close of business on February 5, 2016. As noted above, the payment of this distribution triggered the end of the subordination period and all of the then-outstanding subordinated units converted to common units on a one-for-one basis on February 16, 2016.

We allocated the February 2016 distribution in accordance with the third target distribution level (see "Incentive Distribution Rights—Percentage Allocations of Available Cash" below for additional information.)

Incentive Distribution Rights. Our general partner also currently holds IDRs 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 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 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 IDRs and that there are no arrearages on common units.

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	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%

We reached the second target distribution in connection with the distribution declared in respect of the fourth quarter of 2013. We reached the third target distribution in connection with the distribution declared in respect of the second quarter of 2014.

Our payment of IDRs as reported in distributions to unitholders – general partner in the statement of partners' capital during the years ended December 31 follow.

	Year ended December 31,		
	2015	2014	2013
	(In thousands)		
IDR payments	$6,743	$2,326	$—

Our general partner was not entitled to receive IDR payments prior to the distribution declared and paid in respect of the fourth quarter of 2013 based on the amount of the distributions declared and paid per common and subordinated unit.

For the purposes of calculating net income attributable to general partner, the financial impact of IDRs is recognized in respect of the quarter for which the distributions were declared. For the purposes of calculating distributions to unitholders in the statements of partners' capital and cash flows, IDR payments are recognized in the quarter in which they are paid.

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11. EARNINGS PER UNIT

The following table details the components of (loss) earnings per limited partner unit.

	Year ended December 31,		
	2015	2014	2013
	(In thousands, except per-unit amounts)		
Numerator for basic and diluted EPU:			
Allocation of net (loss) income among limited partner interests:			
Net (loss) income attributable to common units	$(125,437)	$(16,324)	$23,227
Net (loss) income attributable to subordinated units	(70,173)	(10,793)	19,322
Net (loss) income attributable to limited partners	$(195,610)	$(27,117)	$42,549
Denominator for basic and diluted EPU:			
Weighted-average common units outstanding – basic	39,217	33,311	26,951
Effect of nonvested phantom units	—	—	150
Weighted-average common units outstanding – diluted	39,217	33,311	27,101
Weighted-average subordinated units outstanding – basic and diluted	24,410	24,410	24,410
(Loss) earnings per limited partner unit:			
Common unit – basic	$(3.20)	$(0.49)	$0.86
Common unit – diluted	$(3.20)	$(0.49)	$0.86
Subordinated unit – basic and diluted	$(2.88)	$(0.44)	$0.79

During the years ended December 31, 2015 and 2014, we excluded 109,201 and 231,875 units, respectively, in our calculation of the effect of nonvested phantom units because they were anti-dilutive. There were no anti-dilutive units during for the year ended December 31, 2013

12. UNIT-BASED COMPENSATION

SMLP Long-Term Incentive Plan. The SMLP Long-Term Incentive Plan (the "SMLP 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 SMLP 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 SMLP LTIP. As of December 31, 2015, approximately 4.4 million common units remained available for future issuance.
The SMLP 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 SMLP LTIP may make grants under the SMLP LTIP that contain such terms, consistent with the SMLP LTIP, as the administrator may determine are appropriate, including vesting conditions. The administrator of the SMLP 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 SMLP 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.

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The following table presents phantom and restricted unit activity:

	Units	Weighted-average grant date fair value
Nonvested phantom and restricted units, January 1, 2013	131,558	$ 20.00
Phantom and restricted units granted	156,165	26.33
Phantom units forfeited	(4,041)	25.99
Nonvested phantom and restricted units, December 31, 2013	283,682	23.41
Phantom units granted	136,867	42.32
Phantom and restricted units vested	(61,917)	25.33
Phantom units forfeited	(22,430)	25.56
Nonvested phantom units, December 31, 2014	336,202	30.61
Phantom units granted	289,735	29.21
Phantom units vested	(229,497)	27.66
Phantom units forfeited	(16,529)	35.09
Nonvested phantom units, December 31, 2015	379,911	$ 31.13

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. A restricted unit is a common limited partner unit that is subject to a restricted period during which the unit remains subject to forfeiture.

The phantom units granted in connection with the IPO vested on the third anniversary of the IPO. All other phantom units granted to date vest ratably over a three-year period. Grant date fair value is determined based on the closing price of our common units on the date of grant multiplied by the number of phantom units awarded to the grantee. Holders of all phantom units granted to date 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. Upon vesting, phantom unit awards may be settled, at our discretion, in cash and/or common units, but the current intention is to settle all phantom unit awards with common units. The restricted units granted in 2013 maintained the vesting provisions of the share-based compensation awards they replaced, each of which had an original vesting period of four years.

As of December 31, 2015, the unrecognized unit-based compensation related to the SMLP LTIP was $5.5 million. Incremental unit-based compensation will be recorded over the remaining vesting period of approximately 1.17 years. Due to the limited and immaterial forfeiture history associated with the grants under the SMLP 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 SMLP LTIP follows.

	Year ended December 31,		
	2015	2014	2013
	(In thousands)		
SMLP LTIP unit-based compensation	$6,174	$4,696	$2,999

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 were granted through January 2012. Each grant vests ratably over five years and provides for accelerated vesting in certain limited circumstances. Summit Investments valued the SMP Net Profits Interests utilizing an option pricing method, which modeled membership interests as call options on the underlying equity value of Summit Investments and considered the rights and preferences of each class of equity to allocate a fair value to each class. Summit Investments retained the SMP Net Profits Interests and, as such, they are not reflected in SMLP's financial statements subsequent to the IPO, except as noted below.

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Due to common control, we recognized the SMP Net Profits Interests' noncash compensation expense that had been allocated to the contributed subsidiaries prior to their respective drop down date. Unit-based compensation recognized in general and administrative expense related to the SMP Net Profits Interests was as follows:

	Year ended December 31,		
	2015	2014	2013
	(In thousands)		
SMP net profits interests unit-based compensation	$85	$340	$830

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 (the "DFW Net Profits Interests"). Grants were made in 2009 and 2010. Each grant vested ratably over four years and provided for accelerated vesting in certain limited circumstances. The DFW Net Profits Interests were valued utilizing an option pricing method, which modeled membership interests as call options on the underlying equity value of DFW Midstream and considered the rights and preferences of each class of equity to allocate a fair value to each class.

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.

13. RELATED-PARTY TRANSACTIONS

Acquisitions. See Notes 1, 8 and 15 for disclosure of the Polar and Divide Drop Down, the Red Rock Drop Down, the Bison Drop Down and the funding of those transactions.

Reimbursement of Expenses from General Partner. 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. Our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us. Due to affiliate on the consolidated balance sheet represents the payables to our general partner for expenses incurred by it and paid on our behalf.

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

	Year ended December 31,		
	2015	2014	2013
	(In thousands)		
Operation and maintenance expense	$21,537	$19,782	$14,323
General and administrative expense	21,116	22,370	18,662

Expenses Incurred by Summit Investments. Prior to the Polar and Divide Drop Down, the Red Rock Drop Down and the Bison Drop Down, Summit Investments incurred:

- certain support expenses and capital expenditures on behalf of the contributed subsidiaries. These transactions were settled periodically through membership interests prior to the respective drop down;
- interest expense that was related to capital projects for the contributed subsidiaries. As such, the associated interest expense was allocated to the respective contributed subsidiary's capital projects as a noncash contribution and capitalized into the basis of the asset; and
- SMP Net Profits Interests accounted for as compensatory awards. As such, the annual expense associated with the SMP Net Profits was allocated to the respective contributed subsidiary and is reflected in general and administrative expenses in the statement of operations.

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14. COMMITMENTS AND CONTINGENCIES

Operating Leases. We and Summit Investments lease certain office space to support our operations. We have determined that our leases are operating leases. We recognize total rent expense incurred or allocated to us in general and administrative expenses. Rent expense related to operating leases, including rent expense incurred on our behalf and allocated to us, was as follows:

	Year ended December 31,		
	2015	2014	2013
	(In thousands)		
Rent expense	$1,990	$1,786	$1,495

Future minimum lease payments for the Partnership's operating leases are immaterial.

Environmental Matters. There are no material liabilities related to environmental remediation costs, arising from claims, assessments, litigation, fines, or penalties and other sources in the accompanying financial statements at December 31, 2015 or December 31, 2014. However, we can provide no assurance that significant costs and liabilities will not be incurred in the future. We are currently not aware of any material contingent liabilities that exist with respect to environmental matters.

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 or those arising in the normal course of business would not individually or in the aggregate have a material adverse effect on the Partnership's financial position or results of operations.

15. ACQUISITIONS AND DROP DOWN TRANSACTIONS

Polar and Divide. On May 18, 2015, SMLP acquired the Polar and Divide system, a crude oil and produced water gathering system, including under-development transmission pipelines, located in North Dakota from a subsidiary of Summit Investments, subject to customary working capital and capital expenditures adjustments. We funded the initial combined purchase price of $290.0 million with (i) $92.5 million of borrowings under SMLP’s revolving credit facility and (ii) the issuance of $193.4 million of SMLP common units and $4.1 million of general partner interests to SMLP’s general partner in connection with the May 2015 Equity Offering. In July 2015, we received $4.3 million of cash from a subsidiary of Summit Investments as payment in full for working capital and capital expenditure adjustments.

Summit Investments accounted for its purchase of Meadowlark Midstream, the entity that Polar Midstream was carved out of, 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 initial acquisition on February 15, 2013. 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. We recognized the acquisition of Polar Midstream at Summit Investments' historical cost of construction and fair value of assets and liabilities at acquisition, which reflected its fair value accounting for the acquisition of Meadowlark Midstream, due to common control.

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

Purchase price assigned to Polar Midstream		$216,105
Current assets	$368	
Property, plant, and equipment	9,755	
Other noncurrent assets	7,201	
Total assets acquired	17,324	
Current liabilities	4,592	
Total liabilities assumed	$4,592	
Net identifiable assets acquired		12,732
Goodwill		$203,373

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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.

Red Rock Gathering System. On March 18, 2014, SMLP acquired Red Rock Gathering, a natural gas gathering and processing system located in Colorado and Utah, from a subsidiary of Summit Investments, subject to customary working capital adjustments. In October 2012, Summit Investments acquired ETC Canyon Pipeline, LLC ("Canyon") and contributed the Canyon gathering and processing assets to Red Rock Gathering, a newly formed, wholly owned subsidiary of Summit Investments. The Partnership paid total cash consideration of $307.9 million, comprising $305.0 million at the date of acquisition and $2.9 million of working capital adjustments that were recognized in due to affiliate as of December 31, 2014 and settled in February 2015. The acquisition of Red Rock Gathering was funded with the net proceeds from an offering of common units in March 2014, $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 Gathering acquisition 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 for all periods ending after October 23, 2012, the date Summit Investments acquired its interests, and before March 18, 2014.

In 2014, we identified and wrote off the balance associated with a working capital adjustment received after the purchase accounting measurement period closed for Summit Investments' acquisition of Red Rock Gathering. This write off was recognized as a $1.2 million increase to gathering services and other fees for the year ended December 31, 2014.

Lonestar Assets. DFW Midstream completed the acquisition of certain natural gas gathering assets located in the Barnett Shale Play ("Lonestar") from Texas Energy Midstream, L.P. ("TEM") for $10.9 million on September 30, 2014. The Lonestar assets gather natural gas under two long-term, fee-based contracts. SMLP is accounting for the purchase under the acquisition method of accounting. As of September 30, 2014, we preliminarily assigned the full purchase price to property, plant and equipment. During the fourth quarter of 2014, we received additional information from TEM and finalized the purchase price allocation.

Bison Gas Gathering System. On February 15, 2013, Summit Investments acquired BTE. On June 4, 2013, a subsidiary of Summit Investments 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 Meadowlark Midstream and primarily gathers associated natural gas production from customers operating in 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.

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 rights-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 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 the BTE Transaction.

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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

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 Summit Investments and $1.0 million of general partner interests to SMLP's general partner. Summit Investments 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 Summit Investments for the contribution of net assets in excess of consideration paid.

Mountaineer Midstream. We completed the Mountaineer Acquisition on June 21, 2013 for $210.0 million cash consideration. The Mountaineer Midstream natural gas gathering and compression assets are located in the Appalachian Basin which includes the Marcellus Shale formation primarily in Doddridge and Harrison counties 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 Antero Resources Corp. ("Antero"). 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 a subsidiary of Summit Investments. 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 the seller 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

Subsequent Event. On February 25, 2016, the Partnership signed the Contribution Agreement to acquire the 2016 Drop Down Assets. These assets include certain natural gas, crude oil and produced water gathering systems

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located in the Utica Shale, the Williston Basin and the Denver-Julesburg Basin as well as joint venture interests in a natural gas gathering system and a condensate stabilization facility, both located in the Utica Shale.

The consideration to be paid by the Partnership to SMP Holdings for the 2016 Drop Down Assets will consist of (i) a cash payment to SMP Holdings at Initial Close of $360.0 million (the "Initial Payment") which will be funded with borrowings under the Partnership's revolving credit facility and (ii) a deferred payment in 2020 (the "Deferred Payment"). The Deferred Payment will be equal to:

- six-and-one-half (6.5) multiplied by the average adjusted EBITDA, as defined in the Contribution Agreement, of the 2016 Drop Down Assets for 2018 and 2019;
- less the Initial Payment;
- less all capital expenditures incurred for the 2016 Drop Down Assets between the Initial Close and December 31, 2019;
- plus all adjusted EBITDA from the 2016 Drop Down Assets between the Initial Close and December 31, 2019.

At the discretion of the board of directors of our general partner, the Deferred Payment can be paid in cash, SMLP common units or a combination thereof. The present value of the Deferred Payment will be reflected as a liability on our balance sheet until paid. We currently expect that the Deferred Payment will be financed with a combination of (i) net proceeds from the sale of common units by us, (ii) the net proceeds from the issuance of senior unsecured debt by us, (iii) borrowings under our revolving credit facility and/or (iv) other internally generated sources of cash.

Because of the common control aspects in a drop down transaction, the 2016 Drop Down is expected to be deemed a transaction between entities under common control and, as such, will be accounted for on an "as if pooled" basis for all periods in which common control existed. Upon closing the 2016 Drop Down on the Initial Close, SMLP's financial results will retrospectively include the combined financial results of the 2016 Drop Down Assets for all common-control periods.

Supplemental Disclosures – As-If Pooled Basis. As a result of accounting for our drop down transactions similar to a pooling of interests, our historical financial statements and those of Polar Midstream, Red Rock Gathering and the Bison Gas Gathering system have been combined to reflect the historical operations, financial position and cash flows from the date common control began. Revenues and net income for the previously separate entities and the combined amounts, as presented in these consolidated financial statements follow.

	Year ended December 31,		
	2015	2014	2013
	(In thousands)		
SMLP revenues	$358,046	$338,941	$241,089
Polar and Divide revenues (1)	13,273	22,449	3,893
Red Rock Gathering revenues (1)		11,313	50,114
Bison Gas Gathering system revenues (1)			28,590
Combined revenues	$371,319	$372,703	$323,686
SMLP net (loss) income	$(192,212)	$(23,992)	$43,584
Polar and Divide net income (loss) (1)	5,403	6,430	(467)
Red Rock Gathering net income (1)		2,828	9,668
Bison Gas Gathering system net income (1)			52
Combined net (loss) income	$(186,809)	$(14,734)	$52,837

(1) Results are fully reflected in SMLP's revenues and net income on the date common control began, see Note 1.

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

- The acquisition of the Bison Gas Gathering system and Mountaineer Midstream occurred on January 1, 2012. The pro forma results for Bison Midstream and Mountaineer Midstream were derived from revenues and net income in 2013.

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- 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 adjustments in 2013 also reflect the impact of 4,661,547 common unit issuance and the general partner capital contribution to maintain its 2% general partner interest to fund the acquisition of Bison Midstream and Mountaineer Midstream.
- Pro forma adjustments in 2013 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 for Polar and Divide are not required because the system was not in service prior to common control beginning in February 2013.
- The acquisition of the Lonestar assets is immaterial for pro forma purposes and as such has not been reflected below.

	Year ended December 31, 2013 (In thousands, except for per-unit amounts)
Total Bison Midstream and Mountaineer Midstream revenues included in consolidated revenues	$87,196
Total Bison Midstream and Mountaineer Midstream net loss included in consolidated net income	(457)
Pro forma total revenues	$335,837
Pro forma net income	46,904
Pro forma common EPU - basic and diluted	$0.78
Pro forma subordinated EPU - basic and diluted	0.78

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, or (ii) what SMLP’s financial position or results of operations will be for any future periods.

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16. 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, 2015, follows.

	Quarter ended December 31, 2015	Quarter ended September 30, 2015	Quarter ended June 30, 2015	Quarter ended March 31, 2015
	(In thousands, except per-unit amounts)			
Total revenues (1)	$102,601	$106,557	$80,944	$81,217
Net (loss) income attributable to SMLP (2)(3)	$(220,468)	$23,604	$2,985	$1,667
Less net (loss) income attributable to general partner, including IDRs	(2,469)	2,408	1,891	1,568
Net (loss) income attributable to limited partners	$(217,999)	$21,196	$1,094	$99
(Loss) earnings per limited partner unit:				
Common unit – basic	$(3.28)	$0.32	$0.05	$0.00
Common unit – diluted	$(3.28)	$0.32	$0.05	$0.00
Subordinated unit – basic and diluted	$(3.28)	$0.32	$(0.03)	$0.00

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(1) Retrospectively adjusted for the impact of the Polar and Divide Drop Down and reclassification of certain revenues for Bison Midstream.

(2) In the quarter ended December 31, 2015, net loss attributable to SMLP includes $248.9 million of goodwill impairments and $1.6 million of long-lived asset impairments.

(3) In the quarter ended September 30, 2015, net income attributable to SMLP includes $7.7 million of long-lived asset impairments.

	Quarter ended December 31, 2014	Quarter ended September 30, 2014	Quarter ended June 30, 2014	Quarter ended March 31, 2014
	(In thousands, except per-unit amounts)			
Total revenues (1)	$108,230	$90,044	$90,649	$83,780
Net (loss) income attributable to SMLP (2)	$(37,686)	$6,113	$4,036	$3,545
Less net (loss) income attributable to general partner, including IDRs	689	1,204	801	431
Net (loss) income attributable to limited partners	$(38,375)	$4,909	$3,235	$3,114
(Loss) earnings per limited partner unit:				
Common unit – basic	$(0.65)	$0.08	$0.05	$0.08
Common unit – diluted	$(0.65)	$0.08	$0.05	$0.08
Subordinated unit – basic and diluted	$(0.65)	$0.08	$0.05	$0.02

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(1) Retrospectively adjusted for the impact of the Polar and Divide Drop Down and reclassification of certain revenues for Bison Midstream.

(2) In the quarter ended December 31, 2014, net loss attributable to SMLP includes $54.2 million of goodwill impairment and $5.5 million of long-lived asset impairment.

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The amounts for total revenues as originally filed on the respective 2015 and 2014 quarterly reports on Form 10-Q have been retrospectively adjusted for the impact of the Polar and Divide Drop Down and reclassification of certain revenues for Bison Midstream. There was no impact on net income attributable to partners or EPU. A reconciliation of total revenues follows.

	Quarter ended September 30, 2015	Quarter ended June 30, 2015	Quarter ended March 31, 2015
	(In thousands)		
Total revenues as originally reported	$103,249	$77,274	$68,579
Bison revenue reclass	3,308	3,670	4,056
Polar and Divide Drop Down	—	—	8,582
Total revenues	$106,557	$80,944	$81,217

	Quarter ended September 30, 2014	Quarter ended June 30, 2014	Quarter ended March 31, 2014
	(In thousands)		
Total revenues as originally reported	$79,030	$80,796	$76,202
Bison revenue reclass	5,260	4,665	4,399
Polar and Divide Drop Down	5,754	5,188	3,179
Total revenues	$90,044	$90,649	$83,780

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure Matters.

There have been no changes in, or disagreements with, accountants on accounting and financial disclosure matters during the years ended December 31, 2015 and 2014.

Item 9A. Controls and Procedures.

Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit to the Securities and Exchange Commission under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), is recorded, processed, summarized and reported within the time periods specified by the Commission’s rules and forms, and that information is accumulated and communicated to the management of our general partner, including our general partner’s principal executive and principal financial officers (whom we refer to as the Certifying Officers), as appropriate to allow timely decisions regarding required disclosure. SMLP’s management, with the participation of the Chief Executive Officer and Chief Financial Officer of SMLP's general partner, has evaluated the effectiveness of SMLP’s disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this annual report (the "Evaluation Date"). Based on such evaluation, the Chief Executive Officer and Chief Financial Officer of SMLP's general partner have concluded that, as of the Evaluation Date, SMLP’s disclosure controls and procedures are effective.

Changes in Internal Control Over Financial Reporting

There have not been any changes in SMLP’s internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the fourth fiscal quarter of 2015 that have materially affected, or are reasonably likely to materially affect, SMLP's internal control over financial reporting.

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Management’s Annual Report On Internal Control Over Financial Reporting

Our general partner is responsible for establishing and maintaining adequate internal control over financial reporting for the Partnership. With our participation, an evaluation of the effectiveness of our internal control over financial reporting was conducted as of December 31, 2015, based on the framework and criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management has concluded that our internal control over financial reporting was effective as of December 31, 2015. Our independent registered public accounting firm has issued an audit report on our internal control over financial reporting, included below of this report.

/s/ Steven J. Newby
Steven J. Newby
President and Chief Executive Officer, Summit Midstream GP, LLC (the general partner of SMLP)

/s/ Matthew S. Harrison
Matthew S. Harrison
Exective Vice President and Chief Financial Officer, Summit Midstream GP, LLC (the general partner of SMLP)

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

We have audited the internal control over financial reporting of Summit Midstream Partners, LP and subsidiaries (the "Partnership") as of December 31, 2015, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management’s Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Partnership's internal control over financial reporting based on our audit.

We conducted our audit 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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2015 of the Partnership and our report dated February 26, 2016 expressed an unqualified opinion on those financial statements and included an explanatory paragraph related to the retrospective change in the Partnership’s composition of reportable segments.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 26, 2016

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Item 9B. Other Information.

On February 24, 2016, the board of directors of our general partner approved changes to the compensation arrangements of certain of the general partner's named executive officers. Effective March 6, 2016, Mr. Newby's annual base salary was increased to $575,000, Mr. Harrison's annual base salary was increased to $400,000, and Mr. Graves' annual base salary was increased to $375,000. Also, Mr. Harrison's, Mr. Degeyter's, Mr. Graves' and Mr. Mallett's annual equity targets were increased from 125% to 150% of annual base salary, effective March 1, 2016.

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PART III
Item 10. Directors, Executive Officers and Corporate Governance.
Management of Summit Midstream Partners, LP

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

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

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

Currently, SMP Holdings is the sole member of our general partner.

Committees of the Board of Directors

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

The table below shows the current membership of each standing board committee and indicates which directors are independent directors.

Name	Audit Committee	Conflicts Committee	Compensation Committee	Independent Director
Thomas K. Lane			Chair	No
Christopher M. Leininger				No
Curtis A. Morgan				No
Steven J. Newby				No
Jerry L. Peters	Chair	Member		Yes
Scott A. Rogan				No
Jeffrey R. Spinner			Member	No
Susan Tomasky	Member	Chair		Yes
Robert M. Wohleber	Member	Member	Member	Yes

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

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

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

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

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

Any matters approved by the Conflicts Committee in good faith will be conclusively deemed to be approved by all of our partners and not a breach by our general partner of any duties it may owe us or our unitholders. Any unitholder challenging any matter approved by the Conflicts Committee will have the burden of proving that the members of the Conflicts Committee did not subjectively believe that the matter was in the best interests of our partnership. Moreover, any acts taken or omitted to be taken in reliance upon the advice or opinions of experts such as legal counsel, accountants, appraisers, management consultants and investment bankers, where our general partner (or any members of the board of directors of our general partner including any member of the Conflicts Committee) reasonably believes the advice or opinion to be within such person's professional or expert competence, shall be conclusively presumed to have been taken or omitted in good faith.

Compensation Committee. Mr. Lane, Mr. Spinner and Mr. Wohleber serve as the members of the Compensation Committee, with Mr. Lane serving as chair of the committee. The Compensation Committee provides oversight, administers and makes decisions regarding our compensation policies and plans. 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.

Directors and Executive Officers

Directors are appointed for a term of one year and hold office until their successors have been elected or qualified or until the earlier of their death, resignation, removal or disqualification. Officers serve at the discretion of the board of directors of our general partner.

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The following table shows information for the directors and executive officers of our general partner as of February 26, 2016.

Name	Age	Position with Summit Midstream GP, LLC
Steven J. Newby	43	President, Chief Executive Officer and Director
Matthew S. Harrison	45	Executive Vice President and Chief Financial Officer
Brock M. Degeyter	39	Executive Vice President, General Counsel, Chief Compliance Officer and Secretary
Brad N. Graves	49	Executive Vice President, Corporate Development and Chief Commercial Officer
Leonard W. Mallett	59	Executive Vice President and Chief Operations Officer
Thomas K. Lane	59	Director
Christopher M. Leininger	47	Director
Curtis A. Morgan	55	Director
Jerry L. Peters	58	Director
Scott A. Rogan	45	Director
Jeffrey R. Spinner	34	Director
Susan Tomasky	62	Director
Robert M. Wohleber	65	Director

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

Matthew S. Harrison has been the Executive Vice President and Chief Financial Officer of our general partner since March 2015 and was Senior Vice President and Chief Financial Officer of our general partner from May 2012 to March 2015. Prior to joining our general partner, Mr. Harrison was the Senior Vice President and Chief Financial Officer of Summit Investments since September 2011. Mr. Harrison joined Summit Investments from Hiland Partners, LP, where he served as Executive Vice President and Chief Financial Officer, Secretary and Director from February 2008 to September 2011. Prior to joining Hiland, Mr. Harrison was a Director in the Energy & Power Merger & Acquisitions group at Wachovia Capital Markets from October 2007 to February 2008 and a Director in the Mergers & Acquisitions group at A.G. Edwards & Sons, Inc. from July 1999 to October 2007. Mr. Harrison was a Senior Accountant for Price Waterhouse for five years. Mr. Harrison received an MBA from Northwestern University–Kellogg Graduate School of Management in 1999 and a B.S. in Accounting from the University of Tennessee in 1992.

Brock M. Degeyter has been the Executive Vice President, General Counsel, Chief Compliance Officer and Secretary of our general partner since March 2015. Previously, he served as Senior Vice President and General Counsel from May 2012 until March 2015. Mr. Degeyter has been the Chief Compliance Officer of our general partner since January 2014. Mr. Degeyter joined Summit Investments in January 2012 as Senior Vice President and General Counsel. Prior to joining Summit Investments, Mr. Degeyter worked in the corporate legal department for Energy Future Holdings (formerly TXU Corp.) from January 2007 through December 2011 where he served as Director of Corporate Governance and Senior Counsel. Prior to joining Energy Future Holdings, Mr. Degeyter was engaged in private practice with the firm of Correro Fishman Haygood Phelps Walmsley & Casteix LLP from May 2002 through December 2006. Mr. Degeyter is licensed to practice law in the states of Texas and Louisiana. Mr. Degeyter received a B.A. in Political Science from Louisiana State University and a J.D. from Loyola University College of Law in New Orleans.

Brad N. Graves has been the Executive Vice President, Corporate Development and Chief Commercial Officer of our general partner since March 2015. Previously, he served as Senior Vice President of Corporate Development from May 2012 until March 2015. In March 2013, he was promoted to Chief Commercial Officer. Prior to joining our general partner, Mr. Graves was the Senior Vice President of Corporate Development of Summit Investments since April 2010. He was previously a Partner with Crestwood Midstream Partners, LLC from February 2008 until March 2010. Mr. Graves served as Executive Vice President—Business Development of Genesis Energy, LP from August 2006 until November 2007. He also served as Vice President—Offshore Commercial for Enterprise Products Partners L.P. ("Enterprise") from 2004 until August 2006. Prior to 2004, Mr. Graves served in a variety of commercial roles at Enterprise and GulfTerra Energy Partners, LP ("GulfTerra"), prior to its merger with Enterprise. In his roles with Enterprise and GulfTerra, Mr. Graves participated in numerous greenfield projects developed in the Gulf of Mexico. Mr. Graves earned a B.B.A. in Accounting from Texas A&M University in 1989 and an MBA in Marketing and Finance from the University of Saint Thomas in 1994.

Leonard W. Mallett has been Executive Vice President and Chief Operations Officer of our general partner since December 2015. Prior to joining our general partner, Mr. Mallett served as Senior Vice President of Engineering for Enterprise, where he was responsible for the engineering, project management, sourcing and technical support functions supporting all of Enterprise’s pipeline and related plants. Mr. Mallett began his career with TEPPCO as a Project Engineer and spent the next three decades working with TEPPCO and successor entities in various engineering, transportation, and operations roles. At the end of 2006, Enterprise bought TEPPCO’s General Partner from Duke Energy Field Services, at which time Mr. Mallett was serving as SVP of Operations for TEPPCO. Post-merger, Mr. Mallett was named SVP-Environmental, Health and Safety. Mr. Mallett holds a Bachelor of Science in Mechanical Engineering from Prairie View A&M University and a Master of Business Administration from Houston Baptist University.

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

Christopher M. Leininger has served as a director of our general partner since August 2013 and was appointed to the board in connection with his affiliation with Energy Capital Partners. Mr. Leininger has been Deputy General Counsel at Energy Capital Partners since 2006. Prior to joining Energy Capital Partners, Mr. Leininger was an associate at the law firm of Latham & Watkins LLP and a member of its Finance department. Mr. Leininger serves on the boards of EnergySolutions, Inc. and PLH Group, Inc. Mr. Leininger received a B.A. in History and Political Science from the University of San Diego and a J.D. from the University of Virginia School of Law. Mr. Leininger was selected to serve as a director on the board due to his affiliation with Energy Capital Partners, his knowledge of the energy industry and his financial and business expertise.

Curtis A. Morgan has served as a director of our general partner since May 2012 and was appointed to the board in connection with his affiliation with Energy Capital Partners, which controls our general partner. Mr. Morgan has been an Operating Partner of Energy Capital Partners since October 2015. Prior to rejoining Energy Capital Partners (where he previously served as an Operating Partner from May 2009 to May 2010), he served as the President and Chief Executive Officer of EquiPower Resources Corp. from May 2010 to April 2015. Mr. Morgan formerly served as President and Chief Executive Officer of FirstLight Power Enterprises from November 2006 to April 2009. Mr. Morgan has also held leadership positions at NRG Energy, Mirant Corporation and Reliant Energy. Mr. Morgan received a B.A. in Accounting from Western Illinois University and an MBA in Finance and Economics from the University of Chicago. He is a Certified Public Accountant. We believe that Mr. Morgan's extensive executive, financial and operational experience bring important and necessary skills to the board of directors.

Jerry L. Peters has served as a director of our general partner since September 2012. Additionally, Mr. Peters served as the chair of the Conflicts Committee of our general partner until Ms. Tomasky's appointment to the role in

November 2012 and serves as the chair and financial expert of the Audit Committee of our general partner. Mr. Peters has served as the Chief Financial Officer of Green Plains Inc., a publicly-traded vertically-integrated ethanol producer, since May 2007. In 2015, Mr. Peters was appointed Chief Financial Officer and director of the general partner of Green Plains Partners, LP, a publicly traded partnership engaged in fuel storage and transportation services (and collectively with Green Plains Inc., "Green Plains"). Prior to joining Green Plains, Mr. Peters served as Senior Vice President—Chief Accounting Officer for ONEOK Partners from May 2006 to April 2007, as Chief Financial Officer of ONEOK Partners, L.P. from July 1994 to May 2006, and in various senior management roles of

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ONEOK Partners, L.P. from 1985 to May 2006. Prior to joining ONEOK Partners, Mr. Peters was employed by KPMG LLP as a certified public accountant from 1980 to 1985. Mr. Peters received an MBA from Creighton University with an emphasis in finance and a B.S. in Business Administration from the University of Nebraska Lincoln. We believe that Mr. Peters' extensive executive, financial and operational experience bring important and necessary skills to the board of directors.

Scott A. Rogan has served as a director of our general partner since February 2014 and was appointed to the board in connection with his affiliation with Energy Capital Partners. Mr. Rogan joined Energy Capital Partners as a principal in February 2014. Prior to joining Energy Capital Partners, and for the past five years, Mr. Rogan was employed by Barclays Capital ("Barclays") as a Managing Director working in the investment banking division of the natural resources group. Prior to its merger with Barclays in 2008, Mr. Rogan worked for over 10 years in investment banking for Lehman Brothers. Mr. Rogan received a bachelor’s degree in business administration and a master’s degree in professional accounting from the University of Texas at Austin as well as a master’s degree in business administration from the University of Chicago. Mr. Rogan was selected to serve as a director on the board due to his affiliation with Energy Capital Partners, his knowledge of the energy industry and his financial and business expertise.

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

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

Robert M. Wohleber has served as a director of our general partner since August 2013. Mr. Wohleber served as Senior Vice President and Chief Financial Officer of Kerr-McGee Corporation, an oil and gas exploration and production company, from December 1999 to August 2006. From 1996 to 1998, he served as Senior Vice President and Chief Financial Officer of Freeport-McMoran, Inc., one of the largest phosphate fertilizer producers in the United States. He holds a B.B.A. from the University of Notre Dame and an M.B.A. from the University of Pittsburgh. Mr. Wohleber's extensive executive and financial experience in the oil and gas industry bring important and necessary skills to the board of directors.

Code of Ethics

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

Corporate Governance Guidelines

Our Corporate Governance Guidelines, which are available on our website under the “Corporate Governance” subsection of the “Investors” section at www.summitmidstream.com, provide that (i) Jerry L. Peters, as the chairman of our Audit Committee, shall preside over any executive sessions, and (ii) interested parties may communicate

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directly with our independent directors by submitting a specially marked envelope to the Secretary of our general partner.

Section 16(a) Beneficial Ownership Reporting Compliance

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

Item 11. Executive Compensation.

This Compensation Discussion and Analysis ("CD&A") provides information regarding the compensation of our named executive officers ("NEOs") as reported in the Summary Compensation Table and other tables in this document. In this CD&A, we review the compensation decisions and rationale for those decisions relating to our principal executive officer, principal financial officer, our next three most highly compensated executive officers, and, pursuant to SEC regulations requiring such disclosure, one former executive officer.

The following describes the material components of our executive compensation program for the following individuals, who are referred to as the "Named Executive Officers" or "NEOs":

- Steven J. Newby, President and Chief Executive Officer
- Matthew S. Harrison, Executive Vice President and Chief Financial Officer
- Brock M. Degeyter, Executive Vice President, General Counsel, Chief Compliance Officer and Secretary
- Brad N. Graves, Executive Vice President and Chief Commercial Officer
- Leonard W. Mallett, Executive Vice President and Chief Operations Officer (Mr. Mallett's employment commenced on December 1, 2015)
- Rene L. Casadaban, former Senior Vice President and Chief Operating Officer (Mr. Casadaban's employment terminated on September 30, 2015)

The NEOs are employees of Summit Investments and executive officers of our general partner. The NEOs split their working time between SMLP's business and their 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 NEOs' compensation that is allocated to us. The Compensation Committee of the board of directors of our general partner (the "Board") provides oversight, administers and makes decisions regarding our compensation policies and plans.

Compensation Philosophy and Objectives

We seek to provide reasonable and competitive rewards to executives through compensation and benefit programs structured to:

- Attract and retain outstanding talent
- Drive achievement of short-term and long-term goals
- Reward successful execution of objectives
- Reinforce company culture and leadership competencies
- Align executives with the interests of our unitholders

We employ a pay-for-performance philosophy when designing executive compensation opportunities. Thus, a portion of an executive's target compensation should be performance based through linkage to the achievement of financial and other measures deemed to be drivers in the creation of unitholder value. While the Compensation Committee does not set a specific target allocation among the elements of total direct compensation, most of the compensation opportunity available to each of our NEOs is, by design, contingent on the Partnership's annual and long-term performance.

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Compensation of Named Executive Officers

The Compensation Committee establishes the target total direct compensation of our executives and administers other benefit programs. The Compensation Committee engaged BDO USA, L.L.P. as its independent compensation consultant (the "Compensation Consultant"). The Compensation Consultant provides the Compensation Committee with data, analysis and advice on the structure and level of executive compensation. The Compensation Consultant participates in Compensation Committee meetings and executive sessions of the Compensation Committee meetings as requested. The Compensation Consultant may work with our management on various matters for which the Compensation Committee is responsible. However, the Compensation Committee, not management, directs the activities of the Compensation Consultant. We consider the Compensation Consultant to be independent of the Partnership according to current NYSE listing requirements and SEC guidance.

Partnership management, in consultation with the Compensation Committee chair and the Compensation Consultant, prepares materials for the Compensation Committee relevant to matters under consideration by the Compensation Committee, including market data provided by the Compensation Consultant and recommendations of our Chief Executive Officer (the "CEO") regarding compensation of the other executives. The Compensation Committee works directly with the Compensation Consultant on our CEO’s compensation as required.

Based on market data which we use as a reference, we believe compensation of our NEOs is reasonably competitive with opportunities available to officers holding similar positions at other comparable midstream companies. We seek to set compensation levels for each component of total direct compensation based on our assessment of market practices at or near the median. The Compensation Committee adjusts target compensation for each NEO above or below the median, taking into consideration experience, performance, internal equity and other relevant circumstances.

During the Compensation Committee’s annual review of executive compensation, the Compensation Consultant provided the Compensation Committee with an analysis of positions comparable to the NEOs at peer companies. To develop these exhibits, information from peer company public filings was compiled, including public company proxy statements and annual reports on Form 10-K. The peer group used for 2015 executive compensation consisted of fifteen publicly traded midstream partnerships and limited liability companies with whom we compete for executive talent.

The peer group comprised the following companies:

Access Midstream Partners, L.P.	Markwest Energy Partners, L.P.
American Midstream Partners, L.P.	MidCoast Energy Partners, L.P.
Boardwalk Pipeline Partners, L.P.	Niska Gas Storage Partners LLC
Crestwood Equity Partners L.P.	NuStar Energy L.P.
DCP Midstream Partners, L.P.	Regency Energy Partners L.P.
Enable Midstream Partners, L.P.	Southcross Energy Partners, L.P.
EnLink Midstream Partners, LP	Targa Resources Partners, L.P.
Genesis Energy, L.P.	

The compensation analysis encompassed the primary components of total direct compensation, including annual base salary, annual short-term incentive and long-term incentive awards for the NEOs of these peer group companies. The Compensation Committee considered the information provided to ascertain whether the compensation of our NEOs is aligned with our compensation philosophy and competitive with the compensation for executive officers of the peer group companies. The Compensation Committee reviewed the compensation analysis to confirm that our compensation programs were supporting a competitive total compensation approach that emphasizes incentive-based compensation and appropriately rewards achievement of our objectives. For 2015, the target total direct compensation for the NEOs as set by the Compensation Committee is summarized below. Each element is further discussed in this CD&A.

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Name and Principal Position	Base Salary ($)	2015 Target Annual Bonus: Percent of Base Salary (%)	2015 Target LTIP Award: % of Base Salary (%)	2015 LTIP Target Award Value ($)	2015 Target Total Direct Compensation ($)
Steven J. Newby President and Chief Executive Officer	475,000	150	250	1,187,500	2,375,000
Matthew S. Harrison Executive Vice President and Chief Financial Officer	340,000	100	125	425,000	1,105,000
Brock M. Degeyter Executive Vice President, General Counsel, Chief Compliance Officer and Secretary	305,000	100	125	381,250	991,250
Brad N. Graves Executive Vice President, Corporate Development and Chief Commercial Officer	325,000	100	125	406,250	1,056,250
Leonard W. Mallett (1) Executive Vice President and Chief Operations Officer	350,000	N/A	N/A	N/A	N/A
Rene L. Casadaban (2) Senior Vice President and Chief Operating Officer	305,000	75	125	381,250	915,000

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(1) Mr. Mallett received $29,167 in base salary for 2015, equal to approximately one twelfth of his annual base salary. In lieu of a target LTIP award based on a percentage of base salary, Mr. Mallett's employment agreement entitled him to a grant of LTIP units equal in value to $1.6 million, which he was granted on December 1, 2015.
(2) As more fully set forth in the Summary Compensation Table below, pursuant to his severance agreement executed on September 30, 2015, Mr. Casadaban is not entitled to receive any portion of his 2015 target annual bonus. Instead, consistent with the terms of his employment and severance agreements, Mr. Casadaban received the sum of his 2015 base salary and his 2014 bonus, plus additional amounts related to continuation of health benefits for a 12-month period. In total, Mr. Casadaban will receive $539,992 (less applicable tax withholdings and other deductions) in 12 monthly installments beginning on the effective date of his severance agreement, in connection with the termination of his employment.

Components of Executive Compensation

The primary elements of compensation for the NEOs are base salary, annual incentive compensation and long-term equity-based compensation awards. The NEOs also receive certain retirement, health, welfare and additional benefits.

Base Salary. The base salaries for our NEOs are reviewed annually by the Compensation Committee. Base salaries for our NEOs have generally been set at levels deemed necessary to attract and retain individuals with superior talent. Due to external market conditions in 2015, the NEOs did not receive a base salary increase in 2015. In connection with his amended and restated employment agreement dated February 1, 2016, Mr. Degeyter's base salary increased to $350,000 per year.

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The base salaries of our NEOs, a portion of which are allocated to and reimbursed by the Partnership, are set forth in the following table:

Name and Principal Position	2015 Base Salary ($)	
Steven J. Newby President and Chief Executive Officer	475,000	
Matthew S. Harrison Executive Vice President and Chief Financial Officer	340,000	
Brock M. Degeyter Executive Vice President, General Counsel, Chief Compliance Officer and Secretary	305,000	(1)
Brad N. Graves Executive Vice President, Corporate Development and Chief Commercial Officer	325,000	
Leonard W. Mallett Executive Vice President and Chief Operations Officer	350,000	
Rene L. Casadaban Senior Vice President and Chief Operating Officer	305,000	

(1) Salary adjusted from $305,000 to $350,000 in February 2016.

Annual Incentive Compensation. We provide an annual incentive bonus ("annual bonus") to drive the achievement of key business results and to recognize NEOs based on their contributions to those results. The annual bonus plan is a cash-based incentive plan. Incentive amounts are intended to provide total cash compensation near the market range for executive officers in comparable positions when target performance is achieved. Annual bonus compensation levels are set above or below the market range to reflect actual performance results as appropriate when performance is greater or less than expectations. Annual bonus payouts may range from 0% to 200% of the target opportunity and may be adjusted at the discretion of the Compensation Committee.

In March 2015, the Compensation Committee established the 2015 annual bonus plan target opportunities as a percentage of base salary for our NEOs. The 2015 targets increased to 100% from 75% for Messrs. Harrison, Graves, and Degeyter from the previous year. Mr. Newby's 2015 target increased to 150% from 100%. Mr. Mallett's 2015 bonus was prescribed by his employment agreement.

Name and Principal Position (1)	2015 Target Annual Bonus: Percent of Base Salary (%)	2015 Target Bonus: Dollar Value ($)
Steven J. Newby President and Chief Executive Officer	150	712,500
Matthew S. Harrison Executive Vice President and Chief Financial Officer	100	340,000
Brock M. Degeyter Executive Vice President, General Counsel, Chief Compliance Officer and Secretary	100	305,000
Brad N. Graves Executive Vice President, Corporate Development and Chief Commercial Officer	100	325,000
Leonard W. Mallett (2) Executive Vice President and Chief Operations Officer	N/A	N/A

(1) This table omits Mr. Casadaban, whose employment terminated on September 30, 2015. Although the Compensation Committee established a 2015 target annual bonus for Mr. Casadaban, pursuant to his severance agreement, Mr. Casadaban is not entitled to receive a 2015 annual bonus.

(2) The Compensation Committee did not set a target annual bonus for Mr. Mallett, whose employment commenced on December 1, 2015.

In 2015, quantitative factors, as reflected in the corporate scorecard applicable to the senior leadership team (the "SLT Scorecard") determined at least one-half of the annual bonus for Messrs. Harrison, Degeyter and Graves while their respective business unit scorecards accounted for the remainder (the bonus amounts determined based on these scorecards were subject to further adjustments as explained below). For Mr. Newby, the SLT Scorecard determined his entire annual bonus for 2015, subject to further adjustments as explained below. The SLT Scorecard

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contained four factors, each of which are considered by the Board and management as key indicators of the successful execution of our business plan. Those factors included corporate growth, adjusted EBITDA, distributable cash flow per unit and health, safety, environmental, and regulatory goals. Some factors are for all companies owned by Summit Investments, while other factors are related only to the Partnership.

In February 2016, the Compensation Committee and the Board reviewed the SLT Scorecards for 2015 and determined the level of achievement of each key factor. While we achieved less than our adjusted EBITDA target, our distributable cash flow per unit target, and our corporate growth target, we exceeded our health, safety, environmental, and regulatory goals. These results yielded a calculated SLT Scorecard result of 73% of target for the portion of their annual bonuses based on SLT Scorecard results.

In addition to corporate and business unit results reported on scorecards, additional considerations are applied at the discretion of the CEO, the Compensation Committee, or the Board that may affect the amount of the actual bonus earned. Those considerations include judgments regarding overall company performance and business events, industry climate and performance, demonstrated leadership capabilities, and progress on strategic initiatives. For 2015, the Compensation Committee and the Board determined that due to macroeconomic changes beyond our control, plus cost savings realized through tight budget control, additional annual bonus consideration would be provided.

Mr. Newby’s annual bonus payout was $535,000, which is 75% of his target annual bonus for 2015.

Mr. Harrison’s annual bonus payout reflects consideration for the combined performance results of the enterprise technology, finance, and accounting business units. The total amount awarded to Mr. Harrison reflects 75% of his target annual bonus in 2015, or $255,000.

Mr. Degeyter’s annual bonus payout reflects consideration for the performance results of the legal, health, safety, environmental and regulatory business units. The total amount awarded to Mr. Degeyter reflects 80% of his target annual bonus in 2015, or $245,000.

Mr. Graves’ annual bonus payout reflects consideration for performance results of the corporate development business unit. The total amount awarded to Mr. Graves reflects 72% of his target annual bonus in 2015, or $235,000.

Pursuant to his employment agreement, Mr. Mallett will receive a $350,000 cash bonus in March 2016, contingent upon his current employment as of the payment date.

Mr. Casadaban’s employment and severance agreements did not entitle him to receive any portion of his 2015 target annual bonus. Rather, Mr. Casadaban received a severance payment equal to the sum of his 2015 base salary and 2014 annual bonus, plus additional amounts related to the continuation of health benefits.

Only a portion of the NEOs' annual bonus amounts are allocated to and reimbursed by the Partnership. For a discussion of the cost allocation methodology, please refer to "Reimbursement of Expenses from General Partner" in Item 13. Certain Relationships and Related Transactions, and Director Independence. Based on the foregoing discussion, the annual bonus awards to be paid in March 2016 to our NEOs for 2015 performance are as follows:

Name and Principal Position (1)	2015 Annual Bonus Payout ($)
Steven J. Newby President and Chief Executive Officer	535,000
Matthew S. Harrison Executive Vice President and Chief Financial Officer	255,000
Brock M. Degeyter Executive Vice President, General Counsel, Chief Compliance Officer and Secretary	245,000
Brad N. Graves Executive Vice President, Corporate Development and Chief Commercial Officer	235,000
Leonard W. Mallett (2) Executive Vice President and Chief Operations Officer	350,000

(1) This table omits Mr. Casadaban, whose employment terminated on September 30, 2015. Pursuant to his severance agreement, Mr. Casadaban is not entitled to receive a 2015 annual bonus.

(2) Represents a one-time cash bonus pursuant to the terms of Mr. Mallett's employment agreement, payable in March 2016, and contingent upon his employment on the payment date.

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Long-Term Equity-Based Compensation Awards. Our general partner approved the SMLP LTIP pursuant to which eligible officers (including the NEOs), 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. The SMLP LTIP provides for the grant, from time to time at the discretion of the Board 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.

The SMLP 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.

SMLP LTIP award guidelines for NEOs were determined using the Compensation Consultant's analysis for individuals in comparable positions and an analysis of the scope of their roles and duties. These guidelines set an annual equity award target in the amount of 125% of base salary for each of our NEOs other than Mr. Newby, whose targeted annual equity award is 250% of his base salary.

Effective March 15, 2015, based on the recommendation of the Compensation Committee, the Board approved a grant of phantom units to the NEOs. The underlying phantom units vest ratably over a three-year period. Holders of phantom units are entitled to distribution equivalent rights for each phantom unit, providing for a lump sum payment equal to the accrued distributions from the grant date of the phantom units to be paid in cash upon the vesting date. The Compensation Committee selected equity awards that vest contingent on continued service to foster increased unit ownership by the NEOs and as a retention incentive for continued employment with the Partnership.

All SMLP LTIP grants to our NEOs are subject to accelerated vesting on the occurrence of any of the following events: (i) a termination of the NEO's employment other than for cause, (ii) a termination of the NEO's employment by the officer for good reason (as defined in the NEO's employment agreement), (iii) a termination of the NEO's employment by reason of the NEO's death or disability or (iv) a Change in Control (as defined in the applicable award agreement).

To calculate the number of phantom units granted to each NEO, the Compensation Committee determined the dollar amount of the long-term incentive compensation award, and then granted the number of phantom units that had a fair market value equal to that amount on the date of grant. Phantom unit awards granted in March 2015 were as follows:

Name and Principal Position	2015 Target SMLP LTIP Award: % of Base Salary (%)	2015 Phantom Units Awarded (#)	2015 SMLP LTIP Award Value ($)
Steven J. Newby President and Chief Executive Officer	250	56,718	1,925,000
Matthew S. Harrison Executive Vice President and Chief Financial Officer	125	18,563	630,000
Brock M. Degeyter Executive Vice President, General Counsel, Chief Compliance Officer and Secretary	125	18,533	629,000
Brad N. Graves Executive Vice President, Corporate Development and Chief Commercial Officer	125	18,047	612,500
Leonard W. Mallett (1) Executive Vice President and Chief Operations Officer	N/A	85,976	1,600,000
Rene L. Casadaban Senior Vice President and Chief Operating Officer	125	17,502	594,000

(1) In connection with the commencement of his employment, and pursuant to his employment agreement, Mr. Mallett was granted an award of 85,976 LTIP units on December 1, 2015, with a market value of $1.6 million.

Retirement, Health and Welfare and Additional Benefits. The NEOs are eligible to participate in such employee benefit plans and programs as we offer to our employees, subject to the terms and eligibility requirements of those plans.

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401(k) Plan. The NEOs are eligible to participate in a tax qualified 401(k) defined contribution plan to the same extent as all of our other employees. In 2015, 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.

Health Savings Account ("HSA") Program. The NEOs are eligible to participate in a tax qualified health savings account (“HSA”) if they are enrolled in the available high-deductible health plan. The HSA is a tax-free savings account owned by an individual and can be used to pay for current or future qualified medical expenses. Participants determine how much to contribute, when and how to spend the money on eligible medical expenses, and how to invest the balance. The balance remains in the account and is not subject to forfeiture. The Partnership makes annual contributions to all HSA-eligible employees who enroll in an HSA. In 2015, Summit Investments made tax-free HSA contributions of $1,500 to each NEO, except Mr. Mallett.

Deferred Compensation Plan. Effective July 1, 2013, the Board approved a Deferred Compensation Plan (the “DCP”), which is a defined contribution supplemental executive retirement plan established to attract and retain key employees and directors by providing participants with an opportunity to defer receipt of a portion of their salary, bonus, and other specified compensation. The DCP is an unfunded, nonqualified plan that provides each participant in the plan with benefits based on the participant’s notional account balance at the time of retirement or termination. Each participant allocates deferrals among designated mutual fund investments to serve as indices for the purpose of determining notional investment gains and losses to each participant’s account.

Deferrals of SMLP LTIP grants and other equity-based awards are allocated to the Summit Midstream Partners, LP Unit Fund (the “Unit Fund”). The Unit Fund consists of notional common units in SMLP, with each unit approximating the value of one common unit of SMLP. The distribution equivalent rights associated with any SMLP LTIP grant may be allocated to any available investment option, other than the Unit Fund. Messrs. Newby, Harrison and Graves made a DCP deferral election for 2015.

The DCP is filed as Exhibit 10.1 to the Partnership’s Current Report on Form 8-K filed on July 3, 2013.

Tax Preparation and Advisory Services. Pursuant to the terms of their employment agreements, all NEOs are entitled to reimbursement for tax preparation and advisory services expenses of up to $12,000 per year. Expenditures for these additional benefits are disclosed by individual in footnote 5 to the Summary Compensation Table.

Employment and Severance Arrangements. Our NEOs each have employment agreements with Summit Investments. Elements of the NEOs’ total direct compensation are subject to periodic review and may be adjusted accordingly by the Compensation Committee.

Mr. Newby’s employment agreement, which was amended and restated on July 20, 2015 and took effect on August 13, 2015, 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 30 days prior to the expiration of the then-applicable term. Mr. Newby’s employment agreement provides for an annual base salary of $475,000, and a performance-based bonus ranging from 0% to 300% of base salary, with a target of 150% of base salary. Mr. Newby is entitled to receive a prorated annual bonus (based on target) if his employment is terminated by Mr. Newby with good reason, or by the Company without cause or as a result of a non-extension of the term, or due to death or disability. In addition, Mr. Newby’s employment agreement also provides for reimbursement of certain business expenses incurred in connection with his employment, including company-paid tax preparation and advisory services of up to $12,000 per year.

Mr. Newby’s employment agreement provides for a cash severance payment upon a termination resulting from a non-extension of the term by the Company, by the Company without cause or by Mr. Newby for good reason, which is defined generally as the officer's termination of employment within two years after the occurrence of (i) a material diminution in Mr. Newby’s authority, duties or responsibilities, (ii) a material diminution in Mr. Newby’s base salary, target bonus (as a percentage of base salary) or annual bonus range (as a percentage of base salary), (iii) a material change in the geographic location at which the officer must perform his services under the agreement (iv) a change in Mr. Newby’s reporting relationship resulting in Mr. Newby no longer reporting directly to the board of directors of the Company or the general partner or (v) any other action or inaction that constitutes a material breach of the employment agreement by the Company (each a "Qualifying Termination"). In the event of a Qualifying Termination, Mr. Newby’s severance payment will be equal to two 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. 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-

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termination non-solicitation covenant. If Mr. Newby's employment terminates as a result of his non-extension of the term, the Company may choose to subject him to a non-competition covenant for up to one year post-termination. If the Company exercises this "noncompete option", then Mr. Newby would be entitled to a severance payment in an amount equal to the sum of his annual base salary and annual bonus payable in respect of the preceding year, multiplied by a fraction, the numerator of which is equal to the number of days from the date of termination through the expiration of the restricted period (as elected by the Company) and the denominator of which is 365. In this case, the severance payment will be payable in equal installments over the restricted period. Following any termination of employment, the Company has agreed to pay the out-of-pocket premium cost to continue Mr. Newby'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. Newby's employment agreement also provides that all equity awards granted to Mr. Newby under the LTIP and held by him as of immediately prior to a change in control of us will become fully vested immediately prior to the change in control.

Mr. Newby's employment agreement provides that, if any portion of the payments or benefits provided to Mr. Newby would be subject to the excise tax imposed in connection with Section 4999 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 on October 16, 2015, has an initial term that expires on March 1, 2017, and is then automatically extended for successive one-year periods, unless either party gives notice of non-extension to the other no later than 30 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 200% of base salary, with a target of 100% of base salary. Mr. Harrison is entitled to receive a prorated annual bonus (based on target) if his employment is terminated by Mr. Harrison with good reason, or by the Company without cause or as a result of a non-extension of the term, or due to death or disability. In addition, Mr. Harrison's employment agreement also provides for reimbursement of certain business expenses incurred in connection with his employment, including company-paid tax preparation and advisory services of up to $12,000 per year.

Mr. Harrison's employment agreement provides for a cash severance payment upon a termination resulting from a non-extension of the term by the Company, by the Company without cause or by Mr. Harrison for good reason, which is defined generally as the officer's termination of employment within two years after the occurrence of (i) a material diminution in Mr. Harrison's authority, duties or responsibilities, (ii) a material diminution in Mr. Harrison's base salary, target bonus (as a percentage of base salary) or annual bonus range (as a percentage of base salary), (iii) a material change in the geographic location at which the officer must perform his services under the agreement or (iv) any other action or inaction that constitutes a material breach of the employment agreement by the Company (each a "Qualifying Termination"). In the event of a Qualifying Termination, Mr. Harrison's severance payment will be equal 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 terminates as a result of his non-extension of the term, the Company may choose to subject him to a non-competition covenant for up to one year post-termination. If the Company exercises this "noncompete option", then Mr. Harrison would be entitled to a severance payment in an amount equal to the sum of his annual base salary and annual bonus payable in respect of the preceding year, multiplied by a fraction, the numerator of which is equal to the number of days from the date of termination through the expiration of the restricted period (as elected by the Company) and the denominator of which is 365. In this case, the severance payment will be payable in equal installments over the restricted period. Following any termination of employment, the Company 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 as of 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 4999 of the Internal Revenue Code,

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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 February 1, 2016, is substantially similar to Mr. Harrison's employment agreement, except that (i) it provides for an annual base salary of $350,000 and (ii) it has an initial term that expires on March 1, 2018.

Mr. Graves' employment agreement, which was amended and restated on March 1, 2015, 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. Graves' employment agreement provides for an annual base salary of $325,000, and a performance-based bonus ranging from 0% to 200% of base salary, with a target of 100% of base salary. Mr. Graves is entitled to receive a prorated annual bonus (based on target) if his employment is terminated by the Company without cause or due to death or disability. Although Mr. Graves' employment agreement only provides for reimbursement of tax preparation expenses in the amount of $10,000 per year, we have agreed to increase the reimbursement amount to $12,000.

Mr. Graves' employment agreement provides for a cash severance payment upon a termination by the Company without cause or by Mr. Graves for good reason, which is defined generally as the officer's termination of employment within two years after the occurrence of (i) a material diminution in the named executive officer's authority, duties or responsibilities, (ii) a material diminution in the officer's base compensation, (iii) a material change in the geographic location at which the officer must perform his services under the agreement or (iv) any other action or inaction that constitutes a material breach of the employment agreement by the Company (each a "Qualifying Termination"). In the event of a Qualifying Termination other than in the period beginning six months prior to a change in control of the Company and ending on the 12-month anniversary of such a change in control, Mr. Graves' 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. Graves' severance payment will increase to one and one-half times the sum of his annual base salary and the immediately preceding year's bonus.

Following any termination of employment other than one resulting from non-extension of the term, his employment agreement provides that Mr. Graves will be subject to a post-termination non-competition covenant through the severance period, and, following any termination of employment, Mr. Graves will be subject to a one-year post-termination non-solicitation covenant. If Mr. Graves' employment is terminated due to non-extension of the term, the Company may choose to subject him to a non-competition covenant for up to one year post-termination. If the Company exercises this "noncompete option", then Mr. Graves would be entitled to a severance payment in an amount equal to the sum of his annual base salary and annual bonus payable in respect of the preceding year, multiplied by a fraction, the numerator of which is equal to the number of days from the date of termination through the expiration of the restricted period (as elected by the Company) and the denominator of which is 365. In this case, the severance payment will be payable in equal installments over the restricted period. Following any termination of employment, the Company has agreed to pay the out-of-pocket premium cost to continue Mr. Graves' medical and dental coverage for a period not to exceed 18 months, with such coverage terminating if any new employer provides benefits coverage. Mr. Graves' employment agreement also provides that all equity awards granted to Mr. Graves under the LTIP and held by him as of immediately prior to a change in control of us will become fully vested immediately prior to the change in control.

Mr. Graves' employment agreement provides that, if any portion of the payments or benefits provided to Mr. Graves would be subject to the excise tax imposed in connection with Section 4999 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. Graves.

Mr. Mallett's employment agreement, which was entered into on December 1, 2015, has an initial term that expires on December 1, 2017, and is then automatically extended for successive one-year periods, unless either party gives notice of non-extension to the other no later than 30 days prior to the expiration of the then-applicable term. Mr. Mallett's employment agreement provides for an annual base salary of $350,000, and a performance-based bonus ranging from 0% to 200% of base salary, with a target of 100% of base salary. Mr. Mallett is entitled to receive a prorated annual bonus (based on target) if his employment is terminated by Mr. Mallett with good reason, or by the Company without cause or as a result of a non-extension of the term, or due to death or disability. In addition, Mr. Mallett's employment agreement also provides for reimbursement of certain business expenses incurred in connection with his employment, including company-paid tax preparation and advisory services of up to $12,000 per year.

Mr. Mallett’s employment agreement provides for a cash severance payment upon a termination resulting from a non-extension of the term by the Company, by the Company without cause or by Mr. Mallett for good reason, which is defined generally as the officer's termination of employment within two years after the occurrence of (i) a material diminution in Mr. Mallett’s authority, duties or responsibilities, (ii) a material diminution in Mr. Mallett’s base salary, target bonus (as a percentage of base salary) or annual bonus range (as a percentage of base salary), (iii) a material change in the geographic location at which the officer must perform his services under the agreement or (iv) any other action or inaction that constitutes a material breach of the employment agreement by the Company (each a "Qualifying Termination"). In the event of a Qualifying Termination, Mr. Mallett’s severance payment will be equal 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. Mallett will be subject to a post-termination non-competition covenant through the severance period, and, following any termination of employment, Mr. Mallett will be subject to a one-year post-termination non-solicitation covenant. If Mr. Mallett’s employment terminates as a result of his non-extension of the term, the Company may choose to subject him to a non-competition covenant for up to one year post-termination. If the Company exercises this “noncompete option”, then Mr. Mallett would be entitled to a severance payment in an amount equal to the sum of his annual base salary and annual bonus payable in respect of the preceding year, multiplied by a fraction, the numerator of which is equal to the number of days from the date of termination through the expiration of the restricted period (as elected by the Company) and the denominator of which is 365. In this case, the severance payment will be payable in equal installments over the restricted period. Following any termination of employment, the Company has agreed to pay the out-of-pocket premium cost to continue Mr. Mallett’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. Mallett’s employment agreement also provides that all equity awards granted to him under SMLP's long-term incentive plan and held by him as of immediately prior to a change in control of us will become fully vested immediately prior to the change in control.

Mr. Mallett’s employment agreement provides that, if any portion of the payments or benefits provided to Mr. Mallett would be subject to the excise tax imposed in connection with Section 4999 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. Mallett.

Additionally, as an inducement to accept the position of Chief Operations Officer of the Company, on December 1, 2015, received a one-time grant of phantom units valued at $1,600,000, pursuant to a standalone phantom unit award agreement (the "Award Agreement"). Subject to the terms and conditions of the Award Agreement, the underlying phantom units will vest ratably over a three-year period, and are entitled to distribution equivalent rights for each phantom unit, providing for a lump sum payment equal to the accrued distributions from the grant date of the phantom units to be paid in cash upon the vesting date. Furthermore, the phantom units will be subject to accelerated vesting on the occurrence of any of the following events: (i) a termination of the Mr. Mallett’s employment other than for cause, (ii) a termination of employment by Mr. Mallett for good reason (as that term is defined in the employment agreement), (iii) a termination of Mr. Mallett’s employment by reason of death or disability or (iv) a Change in Control (as defined in the Award Agreement). Furthermore, provided that Mr. Mallett remains continuously employed by the Company through March of 2016, he will be entitled to receive an annual cash bonus in the amount of $350,000 and an additional grant of phantom units valued at $600,000.

Risk Assessment Relative to Compensation Programs. The Compensation Committee manages risk as it relates to our compensation plans, programs and structure (collectively, our “compensation practices”). The Compensation Committee meets with management to review whether any aspect of our compensation practices create incentives for our employees to take inappropriate risks that could materially adversely affect the Partnership. Accordingly, we believe that the compensation practices for our NEOs and other employees are appropriately structured and do not pose a material risk to the Partnership. We believe these compensation practices are designed and implemented in a manner that does not promote excessive risk-taking that could damage the value of the Partnership or provide compensatory rewards for inappropriate decisions or behavior.

Compensation Committee Report. The Compensation Committee has reviewed and discussed this CD&A with our management and, based on such review and discussion, has recommended to the Board that the CD&A be included in the Annual Report on Form 10-K.

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Summary Compensation Table for 2015, 2014, and 2013

The following table sets forth certain information with respect to the compensation paid to our NEOs for the years ended December 31, 2015, 2014 and 2013 and allocated to us by our general partner. Under the terms of our partnership agreement, our general partner determines the portion of the NEOs' compensation that is allocated to us. For a discussion of the cost allocation methodology, please refer to "Agreements with Affiliates—Reimbursement of Expenses from General Partner" in Item 13. Certain Relationships and Related Transactions, and Director Independence.

Name and Principal Position	Year	Salary ($) (1)	Bonus ($) (2)	Equity Awards ($) (3)	Non-Equity Incentive Plan Compen-sation($) (4)	All Other Compen-sation ($) (5)	Total ($)
Steven J. Newby	2015	237,500	—	1,925,000		20,619	2,183,119
President and Chief	2014	237,500	—	1,200,000	237,500	16,490	1,691,490
Executive Officer	2013	280,000	—	900,000	332,500	12,845	1,525,345
Matthew S. Harrison	2015	251,600	—	630,000		25,336	906,936
Executive Vice	2014	238,000	—	625,000	185,500	21,965	1,070,465
President and Chief Financial Officer	2013	261,907	—	400,000	225,250	42,251	929,408
Brock M. Degeyter	2015	173,850	—	629,000		19,450	822,300
Executive Vice	2014	213,500	—	600,000	171,500	21,965	1,006,965
President, General Counsel, Chief Compliance Officer and Secretary	2013	225,250	63,750	375,000	208,250	13,388	885,638
Brad N. Graves	2015	97,500	—	612,500		12,071	722,071
Executive Vice	2014	227,500	—	650,000	171,500	21,695	1,070,695
President, Corporate Development and Chief Commercial Officer (6)	2013	—	—	—	—	—	—
Leonard W. Mallett	2015	20,417	—	1,600,000	—	—	1,620,417
Executive Vice	2014	—	—	—	—	—	—
President and Chief Operations Officer (7)	2013	—	—	—	—	—	—
Rene L. Casadaban	2015	213,500	—	594,000	—	19,594	827,094
Senior Vice President	2014	183,000	—	550,000	129,000	18,727	880,727
and Chief Operating Officer (8)	2013	—	—	—	—	—	—

(1) Amounts shown represent the portion of the NEO's base salary allocated to SMLP.

(2) The amount shown in 2013 relates to the portion of Mr. Degeyter's signing bonus allocated to SMLP. The signing bonus for Mr. Degeyter was provided for in his initial employment agreement and paid by Summit Investments.

(3) Amounts shown reflect the grant date fair value of the phantom unit awards granted to the NEOs in March 2014 and March 2013, respectively, in accordance with Financial Accounting Standards Board Accounting Standards Codification Topic 718, Compensation—Stock Compensation ("FASB ASC Topic 718"). For the assumptions made in valuing these awards, See Note 12 to the consolidated financial statements. For additional information, please refer to "Components of Executive Compensation—Long-Term Equity-Based Compensation Awards" above.

(4) Amounts shown represent the incentive bonus earned under our annual incentive bonus program in the fiscal year indicated but paid in the following fiscal year. The amounts shown represent that portion of the NEO's annual bonus that has been allocated to SMLP.

(5) The table below presents the components of "All Other Compensation" allocated to SMLP for each NEO for the fiscal year ended December 31, 2015. For additional information, please see "Components of Executive Compensation—Retirement, Health and Welfare and Additional Benefits" above.

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(6) Compensation information is not provided for fiscal year 2013 for the executive officers who were not NEOs in fiscal year 2013.
(7) Mr. Mallett's employment commenced on December 1, 2015.
(8) Mr. Casadaban's employment terminated on September 30, 2015.
All Other Compensation. The following table sets forth information concerning all other compensation paid to our NEOs in fiscal 2015.

Name (1)	Medical Insurance Premium ($)	Individual Tax Preparation and Annual Medical Examination ($)	Health Savings Account (HSA) Employer Contributions ($)	401(k) Plan Employer Contributions ($)	Total ($)
Steven J. Newby	7,744	5,500	750	6,625	20,619
Matthew S. Harrison	11,461	2,960	1,110	9,805	25,336
Brock M. Degeyter	8,828	2,214	855	7,553	19,450
Brad N. Graves	4,646	3,000	450	3,975	12,071
Rene L. Casadaban	8,131	1,400	788	9,275	19,594

(1) Due to Mr. Mallett's employment commencing on December 1, 2015, he received no other compensation in fiscal 2015.
Grants of Plan-Based Awards in 2015. The following table sets forth information concerning annual incentive awards and phantom unit awards granted to our NEOs in fiscal 2015.

		Estimated Possible Payouts Under Non-Equity Incentive Plan Awards (1)			All Other Stock Awards: Number of Shares of Stocks or Units (2)	Grant Date Fair Value of Stock and Options Awards (3)
Name	Grant Date	Threshold ($)	Target ($)	Maximum ($)	(#)	($)
Steven J. Newby	N/A	N/A	475,000	712,500		
	3/15/2015				56,718	1,925,000
Matthew S. Harrison	N/A	N/A	255,000	382,500		
	3/15/2015				14,776	625,000
Brock M. Degeyter	N/A	N/A	228,750	343,125		
	3/15/2015				14,185	600,000
Brad N. Graves	N/A	N/A	243,750	365,625		
	3/15/2015				15,367	650,000
Leonard W. Mallett (4)	N/A	N/A	N/A	N/A		
	12/1/15				85,976	1,600,000
Rene L. Casadaban (5)	N/A	N/A	228,750	343,125		
	3/15/2015				13,003	594,000

(1) Represents annual incentive opportunities that may be awarded pursuant to our annual incentive program for the year ended December 31, 2015 with payment contingent upon our achievement of pre-established performance goals. For additional information, please see "Components of Executive Compensation—Annual Incentive Compensation" above.
(2) Represents grants of phantom units with distribution equivalent rights under the SMLP LTIP. For additional information, please see "Components of Executive Compensation—Long-Term Equity-Based Compensation Awards"

above.

(3) Amounts shown represent the fair value of the award on the date of the grant, in accordance with FASB ASC Topic 718. For the assumptions made in valuing these awards, see Note 12 to the consolidated financial statements.

(4) The Compensation Committee did not set a target annual bonus for Mr. Mallett, whose employment commenced on December 1, 2015.

(5) Pursuant to the terms of the SMLP LTIP, Mr. Casadaban's unvested LTIP units vested immediately upon the termination of his employment on September 30, 2015. For additional information, please refer to "Components of Executive Compensation-Long-Term Equity-Based Compensation Awards" above.

Narrative Disclosure to the Summary Compensation Table and Grants of the Plan-Based Awards Table. A description of material factors necessary to understand the information disclosed in the tables above with respect to

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salaries, bonuses, equity awards, non-equity incentive plan compensation and all other compensation can be found in the CD&A that precedes these tables.

Outstanding Equity Awards at December 31, 2015. The following table presents information regarding the outstanding equity awards held by our NEOs at December 31, 2015.

Name (1)	Grant Date	Unit Awards Number of Unearned Phantom Units That Have Not Vested (#) (2)	Market Value of Unearned Phantom Units That Have Not Vested ($) (3)
	3/15/2015	56,718	1,062,328
Steven J. Newby	3/15/2014	18,912	354,222
	3/15/2013	11,543	216,200
	3/15/2015	18,563	347,685
Matthew S. Harrison	3/15/2014	9,850	184,490
	3/15/2013	5,129	96,066
	3/15/2015	18,533	347,123
Brock M. Degeyter	3/15/2014	9,456	177,110
	3/15/2013	4,809	90,073
	3/15/2015	18,047	338,020
Brad N. Graves	3/15/2014	10,244	191,870
	3/15/2013	4,809	90,073
Leonard W. Mallett	12/1/2015	85,976	1,610,330

(1) Mr. Casadaban has no outstanding, unvested phantom units as of December 31, 2015. Mr. Casadaban's then-outstanding, unvested phantom units vested upon the termination of his employment on September 30, 2015.

(2) Phantom units granted to the NEOs vest ratably over a three-year period with the first tranche scheduled to vest on the first anniversary of the grant date, subject to continued employment, and accelerated vesting as provided in the applicable award agreement. The NEOs also receive distribution equivalent rights for each phantom unit, providing for a lump sum payment equal to the accrued distributions from the grant date of the phantom units to be paid in cash upon the vesting date.

(3) Amounts were calculated using the closing price of SMLP's publicly traded common units on December 31, 2015.

Phantom Units Vested. The following table represents information regarding the vesting of phantom units during the year ended December 31, 2015 with respect to our NEOs.

Name (1)	Phantom Unit Awards Number of Phantom Units Vested (#)	Value Realized on Vesting ($) (2)
Steven J. Newby	38,500	1,006,040
Matthew S. Harrison	24,807	588,511
Brock M. Degeyter	22,039	533,254
Brad N. Graves	18,683	483,776
Rene L. Casadaban	46,950	869,810

(1) Mr. Mallett's employment commenced on December 1, 2015. None of his phantom units vested during the year ended December 31, 2015.

(2) Amounts represent the value of the phantom units that vested on March 15, 2015, September 28, 2015, and, with respect to Mr. Casadaban in connection with the termination of his employment, on September 30, 2015, plus the distribution equivalent rights earned in tandem. The value of the phantom units that vested on March 15, 2015 was calculated using the closing price of SMLP's publicly traded common units as of March 13, 2015, the trading day

immediately prior to vesting. The value of the units that vested on September 28, 2015 was calculated using the closing price on September 25, 2015, the trading day immediately prior to vesting. With respect to Mr. Casadaban, 30,017 units vested on September 30, 2015. Their value was calculated using the closing price on September 29, 2015, the trading day immediately prior to vesting.

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Pension Benefits. Currently, our general partner does not sponsor or maintain a pension or defined benefit program for our NEOs. This policy may change in the future.

Nonqualified Deferred Compensation Table for 2015. The following table represents information regarding the nonqualified deferred compensation of our NEOs for the year ended December 31, 2015.

Name	Executive Contributions in Last Fiscal Year ($) (1)	Registrant Contributions in Last Fiscal Year ($)	Aggregate Earnings in Last Fiscal Year ($)	Aggregate Withdrawals/Distributions ($)	Aggregate Balance at Last Fiscal Year-End ($)
Steven J. Newby	631,621	—	(36,950)	—	594,670
Matthew S. Harrison	315,945	—	50,456	—	366,401
Brad N. Graves	148,443	—	(1,429)	—	214,447

(1) Amount is included in the "Summary Compensation Table" for the year 2015. For additional information, see "Components of Executive Compensation—Retirement, Health and Welfare and Additional Benefits" above.

Potential Payments upon Termination or Change in Control. The following table sets forth information concerning potential amounts payable to the NEOs upon termination of employment under various circumstances, and upon a change in control, if such event took place on December 31, 2015.

Name and Principal Position (1)	Triggering Event	Salary ($)	Bonus ($)	Pro-Rata Bonus ($)	Health Benefits ($)	Acceleration of Unvested Equity ($) (2)	Total ($)
Steven J. Newby President and Chief Executive Officer (3)	Termination by Reason of Death or Disability	—	—	712,500	25,187	1,632,769	2,370,456
	Termination Without Cause	1,187,500	1,187,500	712,500	25,187	1,632,769	4,745,456
	Resignation for Good Reason	1,187,500	1,187,500	712,500	25,187	1,632,769	4,745,456
	Nonextension of Term by Company	1,187,500	1,187,500	712,500	25,187	—	3,112,687
	Nonextension of Term by Executive, Company Exercises Noncompete	475,000	475,000	—	25,187	—	975,187
	Change in Control (4)	—	—	—	—	1,632,769	1,632,769
Matthew S. Harrison Executive Vice President and Chief Financial Officer (5)	Termination by Reason of Death or Disability	—	—	340,000	25,187	628,279	993,466
	Termination Without Cause	510,000	405,000	340,000	25,187	628,279	1,908,466
	Resignation for Good Reason	510,000	405,000	340,000	25,187	628,279	1,908,466
	Nonextension of Term by Company	510,000	405,000	340,000	25,187	—	1,280,187
		340,000	270,000	—	25,187	—	635,187

Nonextension of Term by Executive, Company Exercises Noncompete						
Change in Control (4)	—	—	—	—	628,279	628,279

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	Termination by Reason of Death or Disability	—	—	305,000	25,187	614,325	944,512
Brock M. Degeyter Executive Vice President, General Counsel, Chief Compliance Officer and Secretary (6)	Termination Without Cause	305,000	260,000	305,000	25,187	614,325	1,509,512
	Resignation for Good Reason	305,000	260,000	—	25,187	614,325	1,204,512
	Termination Without Cause during Change In Control Period	457,500	390,000	305,000	25,187	614,325	1,792,012
	Resignation for Good Reason during Change in Control Period	457,500	390,000	—	25,187	614,325	1,487,012
	Change in Control (4)	—	—	—	—	614,325	614,325
	Nonextension of Term, Company Exercises Noncompete	305,000	260,000	—	25,187	—	590,187
	Termination by Reason of Death or Disability	—	—	325,000	25,187	620,019	970,206
Brad N. Graves Executive Vice President, Corporate Development and Chief Commercial Officer (7)	Termination Without Cause	325,000	265,000	325,000	25,187	620,019	1,560,206
	Resignation for Good Reason	325,000	265,000	—	25,187	620,019	1,235,206
	Termination Without Cause during Change In Control Period	487,500	397,500	325,000	25,187	620,019	1,855,206
	Resignation for Good Reason during Change in Control Period	487,500	397,500	—	25,187	620,019	1,530,206
	Change in Control (4)	—	—	—	—	620,019	620,019
	Nonextension of Term, Company Exercises Noncompete	325,000	265,000	—	25,187	—	615,187
Leonard W. Mallett Executive Vice President and Chief Operations	Termination by Reason of Death or Disability	—	—	350,000	25,187	1,610,330	1,985,517
	Termination Without Cause	525,000	—	350,000	25,187	1,610,330	2,510,517
	Resignation for Good Reason	525,000	—	350,000	25,187	1,610,330	2,510,517

Officer (8)	Nonextension of Term by Company	525,000	—	350,000	25,187	—	900,187
	Change in Control (4)	—	—	—	—	1,610,330	1,610,330

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Nonextension of Term by Executive, Company Exercises Noncompete	350,000	—	—	25,187	—	375,187

(1) This table omits Mr. Casadaban, whose employment terminated on September 30, 2015.
(2) Amounts represent the value of the phantom units that vest upon the occurrence of a triggering event plus the earned dividend equivalent rights that vest in tandem. The value of the phantom units was calculated using the closing price of SMLP's publicly traded common units on December 31, 2015.
(3) Mr. Newby's employment agreement provides that upon termination of employment resulting from a non-extension of the term by Summit Investments, termination by Summit Investments without cause, or by Mr. Newby’s resignation for good reason (each a "Qualifying Termination"), Mr. Newby's severance payment will be equal to two and one-half times the sum of his annual base salary and his annual bonus payable in respect of the immediately preceding year. Mr. Newby is also entitled to receive a prorated annual bonus (based on target) if his employment is terminated as a result of a Qualifying Termination. If Summit Investments exercises the “noncompete option” after Mr. Newby elects not to extend the term, then Mr. Newby is entitled to a severance payment in an amount equal to the sum of his annual base salary and annual bonus payable in respect of the preceding year, multiplied by a fraction, the numerator of which is equal to the number of days from the date of termination through the expiration of the restricted period (as elected by Summit Investments) and the denominator of which is 365. Any unvested equity awards granted to Mr. Newby will immediately vest upon a Qualifying Termination, termination by reason of death or disability, or a change in control. If any portion of the payments or benefits provided to Mr. Newby in connection with a change in control become subject to the excise tax under Section 4999 of the Internal Revenue Code, then the payments and benefits will be reduced to the extent such reduction would result in a greater after-tax benefit to Mr. Newby. Following any termination of employment, Summit Investments has agreed to pay the out-of-pocket premium cost to continue Mr. Newby’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. Newby also had an aggregate balance of $594,670 under the DCP as of December 31, 2015, which will be distributed upon a qualifying triggering event. For additional information, see "Summary Compensation Table for 2015, 2014 and 2013—Nonqualified Deferred Compensation Table for 2015" above.
(4) Single-trigger event without a qualifying termination of employment.
(5) Mr. Harrison’s employment agreement provides that upon termination of employment resulting from a non-extension of the term by Summit Investments, by Summit Investments without cause, or by Mr. Harrison’s resignation for good reason (each a "Qualifying Termination"), Mr. Harrison’s severance payment will be equal to two and one-half times the sum of his annual base salary and his annual bonus payable in respect of the immediately preceding year. Mr. Harrison is also entitled to receive a prorated annual bonus (based on target) if his employment is terminated as a result of a Qualifying Termination or due to death or disability. If Summit Investments exercises the “noncompete option” after Mr. Harrison elects not to extend the term, then Mr. Harrison is entitled to a severance payment in an amount equal to the sum of his annual base salary and annual bonus payable in respect of the preceding year, multiplied by a fraction, the numerator of which is equal to the number of days from the date of termination through the expiration of the restricted period (as elected by Summit Investments) and the denominator of which is 365. Any unvested equity awards granted to Mr. Harrison will immediately vest upon a Qualifying Termination, termination by reason of death or disability, or a change in control. If any portion of the payments or benefits provided to Mr. Harrison would be subject to the excise tax under Section 4999 of the Internal Revenue Code, then the payments and benefits will be reduced to the extent such reduction would result in a greater after-tax payment to Mr. Harrison. 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 also had an aggregate balance of

$366,401 under the DCP as of December 31, 2015, which will be distributed upon a qualifying triggering event. For additional information, see "Summary Compensation Table for 2015, 2014 and 2013-Nonqualified Deferred Compensation Table for 2015" above.

(7) Mr. Degeyter's employment agreement in effect as of December 31, 2015 provided that upon termination of employment by Summit Investments without cause or Mr. Degeyter's resignation for good reason (each a "Qualifying Termination"), Mr. Degeyter's severance payment would have been equal to the sum of his annual base salary and his annual bonus payable in respect of the immediately preceding year. (Mr. Degeyter's employment agreement was amended and restated effective February 1, 2016.) If a Qualifying Termination had occurred within the change in control period beginning six months prior to and ending on the 12-month anniversary of the change in control, Mr. Degeyter's severance payment would have increased 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. Mr. Degeyter would also have been entitled to receive a prorated annual bonus (based on target) if his employment had been terminated by Summit Investments without cause or due to death or disability. If Summit Investments were to have exercised the "noncompete option" after either Summit Investments or Mr. Degeyter elected not to extend the term, then Mr. Degeyter would have been entitled to a severance payment in an amount equal to the sum of his annual base salary and annual bonus payable in respect of the preceding year, multiplied by a fraction, the numerator of which is equal to the number of days from the date of termination through the expiration of the restricted period (as elected by Summit Investments) and the denominator of which is 365. Any unvested equity awards granted to Mr. Degeyter would have immediately vested upon a Qualifying Termination, termination as a result of a non-extension of the term by Summit Investments, termination by reason of death or disability, or a change in control. If any portion of the payments or benefits provided to Mr. Degeyter in connection with a change in control became subject to the excise tax under Section 4999 of the Internal Revenue Code, then the payments and

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benefits would have been reduced to the extent such reduction would result in a greater after-tax benefit to Mr. Degeyter. Mr. Degeyter's employment agreement also provided that following any termination of employment by Summit Investments without cause or by Mr. Degeyter for good reason, Mr. Degeyter would have been entitled to the excess of the out-of-pocket premium cost over such costs for active employees to continue his medical and dental coverage for a period not to exceed 18 months, with such coverage terminating if any new employer provided benefits coverage.

(5) Mr. Graves' employment agreement provides that upon termination of employment by Summit Investments without cause or Mr. Graves' resignation for good reason (each a "Qualifying Termination"), Mr. Graves' 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 within the change in control period beginning six months prior to and ending on the 12-month anniversary of the change in control, Mr. Graves’ 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. Mr. Graves is also 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. If Summit Investments exercises the “noncompete option” after either Summit Investments or Mr. Graves elects not to extend the term, then Mr. Graves is entitled to a severance payment in an amount equal to the sum of his annual base salary and annual bonus payable in respect of the preceding year, multiplied by a fraction, the numerator of which is equal to the number of days from the date of termination through the expiration of the restricted period (as elected by Summit Investments) and the denominator of which is 365. Any unvested equity awards granted to Mr. Graves will immediately vest upon a Qualifying Termination, termination as a result of a non-extension of the term by Summit Investments, termination by reason of death or disability, or a change in control. If any portion of the payments or benefits provided to Mr. Graves in connection with a change in control become subject to the excise tax under Section 4999 of the Internal Revenue Code, then the payments and benefits will be reduced to the extent such reduction would result in a greater after-tax benefit to Mr. Graves. Following any termination of employment, Summit Investments has agreed to pay the out-of-pocket premium cost to continue Mr. Graves’ medical and dental coverage for a period not to exceed 18 months, with such coverage terminating if any new employer provides benefits coverage. Mr. Graves also had an aggregate balance of $214,447 under the DCP as of December 31, 2015, which will be distributed upon a qualifying triggering event. For additional information, see "Summary Compensation Table for 2015, 2014 and 2013-Nonqualified Deferred Compensation Table for 2015" above.

(6) Mr. Mallett’s employment agreement provides that upon termination of employment resulting from a non-extension of the term by Summit Investments, by Summit Investments without cause, or Mr. Mallett’s resignation for good reason (each a "Qualifying Termination"), Mr. Mallett’s severance payment will be equal 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. Mr. Mallett is also entitled to receive a prorated annual bonus (based on target) if his employment is terminated as a result of a Qualifying Termination or due to death or disability. If Company exercises the “noncompete option” after Mr. Mallett elects not to extend the term, then Mr. Mallett is entitled to a severance payment in an amount equal to the sum of his annual base salary and annual bonus payable in respect of the preceding year, multiplied by a fraction, the numerator of which is equal to the number of days from the date of termination through the expiration of the restricted period (as elected by the Company) and the denominator of which is 365. Any unvested equity awards granted to Mr. Mallett will immediately vest upon a Qualifying Termination, termination by reason of death or disability, or a change in control. If any portion of the payments or benefits provided to Mr. Mallett would be subject to the excise tax under Section 4999 of the Internal Revenue Code, then the payments and benefits will be reduced to the extent such reduction would result in a greater after-tax payment to Mr. Mallett. Following any termination of employment, the Company has agreed to pay the out-of-pocket premium cost to continue Mr. Mallett’s medical and dental coverage for a period not to exceed 18 months, with such coverage terminating if any new employer provides benefits coverage.

Compensation Committee Report

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

In March 2015, under the director compensation plan, Mr. Morgan and the independent directors, which include Mr. Peters, Ms. Tomasky and Mr. Wohleber, each received the following:

- an annual cash retainer of $70,000, and
- an annual award of common units with a grant date fair value of approximately $80,000.

In addition, under the director compensation plan, the independent directors receive the following for their respective service on our Board's committees:

- the chairman of the Audit Committee receives an additional annual retainer of $15,000;

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- the chairman of the Conflicts Committee receives an additional annual retainer of $10,000;
- each independent member of any committee (other than the chairman) received an additional annual retainer of $5,000; and
- in connection with the Polar and Divide Drop Down, in May 2015, we paid the members, other than the chairman, of the Conflicts Committee fees of $10,000 and the chairman of the Conflicts Committee fees of $15,000 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 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. We do not compensate employees of the Partnership or Energy Capital Partners for their services as directors.

The following table shows the compensation paid, including amounts deferred, under our director compensation plan in 2015.

Name	Fees earned or paid in cash ($)	Other fees ($)	Unit awards (1) ($)	Compensation deferred ($)	Total ($)
Thomas K. Lane	—	—	—	—	—
Christopher M. Leininger	—	—	—	—	—
Curtis A. Morgan	70,000	—	80,000	—	150,000
Steven J. Newby	—	—	—	—	—
Jerry L. Peters	70,000	20,000	80,000	—	170,000
Jeffrey R. Spinner	—	—	—	—	—
Susan Tomasky	70,000	15,000	80,000	—	165,000
Robert M. Wohleber	70,000	15,000	80,000	—	165,000

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

Compensation Committee Interlocks and Insider Participation

Our Compensation Committee, consists 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 2015, 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 2015, 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.

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

The following table sets forth certain information regarding the beneficial ownership of our common units of:

- each person who is known to us to beneficially own 5% or more of such units to be outstanding (based solely on Schedules 13D and 13G filed with the SEC subsequent to December 31, 2015 and prior to February 17, 2016);
- our general partner;
- each of the directors and NEOs of our general partner; and

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• all of the directors and NEOs of our general partner as a group.

All information with respect to beneficial ownership has been furnished by the respective directors, officers or 5% or more unitholders as the case may be. The amounts and percentage of units beneficially owned are reported on the basis of regulations of the SEC governing the determination of beneficial ownership of securities. Under the rules of the SEC, a person is deemed to be a beneficial owner of a security if that person has or shares voting power, which includes the power to vote or to direct the voting of such security, or investment power, which includes the power to dispose of or to direct the disposition of such security.

In computing the number of common units beneficially owned by a person and the percentage ownership of that person, common units that a person has the right to acquire upon the vesting of phantom units where the units are issuable within 60 days of February 16, 2016, if any, are deemed outstanding, but are not deemed outstanding for computing the percentage ownership of any other person. The percentage of units beneficially owned is based on a total of 66,472,494 common limited partner units outstanding as of February 16, 2016.

Except as indicated by footnote, the persons named in the following table have sole voting and investment power with respect to all units shown as beneficially owned by them, subject to community property laws where applicable.

Name Of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned	
Summit Midstream Partners, LLC (1) (2) (3)	29,854,581	44.9	%
SMP Holdings (2) (3) (4)	29,703,421	44.7	%
Energy Capital Partners II, LLC (1) (3) (5) (6)	32,038,767	48.2	%
SMLP Holdings, LLC (5) (6)	2,184,186	3.3	%
HMI Capital, LLC (7)	3,846,500	5.8	%
OppenheimerFunds, Inc. (8)	3,526,742	5.3	%
Steven J. Newby (2) (10) (11)	34,502	*	
Matthew S. Harrison (2) (10) (11)	23,545	*	
Brock M. Degeyter (2) (10)	34,742	*	
Brad N. Graves (2) (10) (11)	30,666	*	
Leonard W. Mallett (2)	—	*	
Thomas K. Lane (9) (12)	40,000	*	
Christopher M. Leininger (5)	—	*	
Curtis A. Morgan (11)	6,960	*	
Jerry L. Peters (2)	7,433	*	
Scott A. Rogan (13)	—	*	
Jeffrey R. Spinner (13)	—	*	
Susan Tomasky (2)	7,510	*	
Robert M. Wohleber (2)	4,933	*	
All directors and executive officers as a group (consisting of 13 persons)	190,291	*	

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

(1) Summit Investments owns 100% of SMP Holdings, the entity that owns 100% of our general partner. Energy Capital Partners II, LLC ("ECP II") and its parallel and co-investment funds (the "ECP Funds" and together with ECP II, "ECP") hold in the aggregate, 100.0% of the Class A membership interests in Summit Investments, the sole owner of SMP Holdings. ECP II is the general partner of the general partner of each of the ECP Funds that holds membership interests in Summit Investments and has voting and investment control over the securities held thereby. Accordingly, ECP may be deemed to indirectly beneficially own all of the common units held by Summit Investments and SMP Holdings as of February 16, 2016.

(2) The address for this person or entity is 1790 Hughes Landing Blvd., Suite 500, The Woodlands, Texas 77380.

(3) Because of its ownership interest in Summit Investments, ECP is entitled to elect five directors of Summit Investments. In addition, Mr. Lane (who is a partner of Energy Capital Partners), Mr. Leininger (who is managing director and deputy general counsel of Energy Capital Partners), Mr. Morgan (who is an operating partner of Energy Capital Partners), Mr. Rogan (who is a principal of Energy Capital Partners) and Mr. Spinner (who is a principal of Energy Capital Partners) are each directors of our general partner. Neither Mr. Lane, Mr. Leininger, Mr. Morgan, Mr. Rogan nor Mr. Spinner are deemed to beneficially own, and they disclaim beneficial ownership of, any common units held by our general partner, Summit Investments or SMP Holdings.

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(4) SMP Holdings owns 100% of our general partner and 44.7% of our outstanding common units. Given its ownership interest in Summit Investments, ECP may be deemed to indirectly beneficially own all of the common units held by SMP Holdings as of February 16, 2016.
(5) The address for this person or entity is 11943 El Camino Real, Suite 220, San Diego, California 92130.
(6) Energy Capital Partners II, LP and certain of its parallel funds (collectively, the "SMLP Holdings Owners") collectively hold all of the membership interests in SMLP Holdings, LLC ("SMLP Holdings"). ECP II indirectly controls the SMLP Holdings Owners. Accordingly, ECP II and the SMLP Holdings Owners may be deemed to indirectly beneficially own all of the common units held by SMLP Holdings.
(7) The address for this person or entity is One Maritime Plaza, Suite 2020, San Francisco, California 94111.
(8) The address for this person or entity is Two World Financial Center, 225 Liberty Street, New York, New York 10281.
(9) The address for this person or entity is 51 John F. Kennedy Parkway, Suite 200, Short Hills, New Jersey 07078.
(10) Includes common units which the individuals have the right to acquire upon vesting of phantom units, where the units are issuable as of February 16, 2016 or within 60 days thereafter. Such units are deemed to be outstanding in calculating the percentage ownership of such individual (and all directors and officers as a group), but are not deemed to be outstanding as to any other person.
(11) Excludes vested units for which receipt has been deferred into our Deferred Compensation Plan.
(12) Includes 20,000 common units held by Lane Ventures LLC ("Lane Ventures"). Two of Mr. Lane's estate planning trusts collectively own a majority of the membership interests in Lane Ventures and as a result, Mr. Lane may be deemed to indirectly beneficially own the common units held by Lane Ventures.
(13) The address for this person or entity is 1000 Louisiana, Suite 5200, Houston, Texas 77002.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table provides information as of December 31, 2015 with respect to the Partnership's common units that may be issued under the 2012 Long-Term Incentive Plan.

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a) (1)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	379,911	n/a	4,351,120
Equity compensation plans not approved by security holders	n/a	n/a	n/a
Total	379,911	n/a	4,351,120

(1) Amount shown represents phantom unit awards outstanding under the SMLP LTIP at December 31, 2015. The awards are expected to be settled in common units upon the applicable vesting date and are not subject to an exercise price.

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

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

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

The general partner's board of directors, at its discretion, may terminate the SMLP LTIP at any time with respect to the common units for which a grant has not previously been made. The SMLP LTIP will automatically terminate on the 10th anniversary of the date it was initially adopted by our general partner. The general partner's board of directors also has the right to alter or amend the SMLP LTIP or any part of it from time to time or to amend any outstanding award made under the SMLP 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.

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

Of the 42,062,644 common units outstanding at December 31, 2015, Summit Investments and a subsidiary owned 5,444,731 common units and all of our 24,409,850 subordinated units, which converted to common units on a one-for-one basis on February 16, 2016. In addition, SMP Holdings owns and controls our general partner, which owns all of our IDRs and a 2% general partner interest represented by 1,354,700 general partner units.

Distributions and Payments to our General Partner and its Affiliates

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

Operational Stage

Distributions of available cash to our general partner and its affiliates. Unless distributions exceed the minimum quarterly distribution, we make cash distributions 98.0% to our unitholders pro rata and 2.0% to our general partner, assuming it makes any capital contributions necessary to maintain its 2.0% interest in us. In addition, if distributions exceed the minimum quarterly distribution and other higher target distribution levels, our general partner, by virtue of its IDRs, is entitled to increasing percentages of the distributions, up to 50.0% of the distributions above the highest target distribution level. For additional information, see Note 10 to the consolidated financial statements.

For the year ended December 31, 2015, our general partner received distributions of approximately $9.8 million on its 2.0% general partner interest and IDRs and a subsidiary of Summit Investments received distributions of approximately $67.4 million on its common and subordinated units.

Payments to our general partner and its affiliates. See "Agreements with Affiliates—Reimbursement of Expenses from General Partner" below.

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

Liquidation Stage

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

Agreements with Affiliates

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

Reimbursement of Expenses from General Partner. 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. Our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us. Operation and maintenance expenses incurred by the general partner and reimbursed by us under our partnership agreement were $21.5 million in 2015. General and administrative expenses incurred by the general partner and reimbursed by us under our partnership agreement were $21.1 million in 2015. As of December 31, 2015, we had a payable of $1.1 million to the general partner for expenses that were paid on our behalf.

Expense Allocations. During the period from January 1, 2015 to May 18, 2015, Summit Investments incurred interest expense which was related to capital projects at Polar and Divide. As such, the associated interest expense was allocated to Polar and Divide as a noncash contribution and capitalized into the basis of the asset.

Certain of Summit Investments' current and former employees received Class B membership interests, classified as net profits interests, in Summit Investments (the "Net Profits Interests"). The Net Profits Interests participate in distributions upon time vesting and the achievement of certain distribution targets to Class A members or higher priority vested Net Profits Interests. The Net Profits Interests were accounted for as compensatory awards.

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Expenses Paid by Summit Investments on Behalf of Polar and Divide. Prior to the Polar and Divide Drop Down, Summit Investments incurred certain support expenses and capital expenditures on behalf of Polar and Divide during the year ended December 31, 2015. These transactions were settled periodically through membership interests prior to the Polar and Divide Drop Down.

Review, Approval and Ratification of Related-Person Transactions

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

For purposes of the policy, a "related person" is any director or executive officer of SMLP's general partner, any nominee for director, any unitholder known to SMLP to be the beneficial owner of more than 5% of any class of the SMLP's common units, and any immediate family member, affiliate or controlled subsidiary of any such person. A "related person transaction" is generally a transaction in which SMLP is, or SMLP's general partner or any of SMLP's subsidiaries is, a participant, where the amount involved exceeds $120,000, and a related person has a direct or indirect material interest. Transactions resolved under the conflicts provision of the partnership agreement are not required to be reviewed or approved under the policy.

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

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

Director Independence

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

Item 14. Principal Accounting Fees and Services.

Audit Fees. Our audit committee has ratified Deloitte & Touche LLP, Independent Registered Public Accounting Firm, to audit the books, records and accounts of SMLP for the year ended December 31, 2015. The fees billed by Deloitte & Touche LLP for the audit of consolidated financial statements and other services rendered for the years ended December 31, 2015 and 2014 follow.

	Year ended December 31,	
	2015	2014
Audit fees (1)	$2,132,740	$2,131,464
Audit-related fees (2)	—	322,572
Tax fees (3)	801,298	447,614
All other fees	—	—
Total	$2,934,038	$2,901,650

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(1) Audit fees are fees billed by Deloitte & Touche LLP for professional services for the audit and quarterly reviews of the Partnership’s consolidated financial statements, review of other SEC filings, including registration statements, and issuance of comfort letters and consents.

(2) Audit-related fees are fees billed by Deloitte & Touche LLP for assurance and related services related to consultations and audits performed in connection with acquisitions and assistance with the implementation of Section 404 of the Sarbanes-Oxley Act.

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(3) Tax fees are billed by Deloitte Tax LLP for tax compliance services, including the preparation of state, federal and Schedule K-1 tax filings and other tax planning and advisory services.

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

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PART IV
Item 15. Exhibits, Financial Statement Schedules.
(a)(1) Financial Statements
Included in Part II, Item 8, of this report:
Summit Midstream Partners, LP and Subsidiaries:

(2) Financial Statement Schedules
All schedules are omitted because the required information is inapplicable or the information is presented in the financial statements or the notes thereto.
(3) Exhibit Index
An “Exhibit Index” has been filed as part of this Report included below and is incorporated herein by this reference. Schedules other than those listed above are omitted because they are not required, are not material, are not applicable, or the required information is shown in the financial statements or notes thereto.
In reviewing the agreements included as exhibits to this annual report, please remember they are included to provide information regarding their terms and are not intended to provide any other factual or disclosure information about us or the other parties to the agreements. The agreements contain representations and warranties by each of the parties to the applicable agreement. These representations and warranties have been made solely for the benefit of the other parties to the applicable agreement and:

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

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

Exhibit number	Description
3.1	First Amended and Restated Agreement of Limited Partnership of Summit Midstream Partners, LP, dated as of October 3, 2012 (Incorporated herein by reference to Exhibit 3.1 to SMLP's Current Report on Form 8-K dated October 4, 2012 (Commission File No. 001-35666))
3.2	Amended and Restated Limited Liability Company Agreement of Summit Midstream GP, LLC, dated as of October 3, 2012 (Incorporated herein by reference to Exhibit 3.2 to SMLP's Current Report on Form 8-K dated October 4, 2012 (Commission File No. 001-35666))
3.3	Certificate of Limited Partnership of Summit Midstream Partners, LP (Incorporated herein by reference to Exhibit 3.1 to SMLP's Form S-1 Registration Statement dated August 21, 2012 (Commission File No. 333-183466))

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3.4	Certificate of Formation of Summit Midstream GP, LLC (Incorporated herein by reference to Exhibit 3.4 to SMLP's Form S-1 Registration Statement dated August 21, 2012 (Commission File No. 333-183466))
4.1	Investor Rights Agreement, dated as of October 3, 2012, by and among EFS-S, LLC, Summit Midstream GP, LLC and Summit Midstream Partners, LLC (Incorporated herein by reference to Exhibit 4.1 to SMLP's Current Report on Form 8-K dated October 4, 2012 (Commission File No. 001-35666))
10.1	Unit Purchase Agreement, dated as of June 4, 2013, by and between, Summit Midstream Partners, LP and Summit Midstream Partners Holdings, LLC (Incorporated herein by reference to Exhibit 10.3 to SMLP's Current Report on Form 8-K dated June 5, 2013 (Commission File No. 001-35666))
10.2	Purchase Agreement, dated as of June 12, 2013, by and among Summit Midstream Holdings, LLC, Summit Midstream Finance Corp., Summit Midstream GP, LLC, the Guarantors named therein and the Initial Purchasers named therein (Incorporated herein by reference to Exhibit 1.1 to SMLP's Current Report on Form 8-K dated June 17, 2013 (Commission File No. 001-35666))
10.3	Indenture, dated as of June 17, 2013, by and among Summit Midstream Holdings, LLC, Summit Midstream Finance Corp., the Guarantors party thereto and U.S. Bank National Association (including form of the 7½% senior notes due 2021) (Incorporated herein by reference to Exhibit 4.1 to SMLP's Current Report on Form 8-K dated June 17, 2013 (Commission File No. 001-35666))
10.4	Registration Rights Agreement, dated as of June 17, 2013, by and among Summit Midstream Holdings, LLC, Summit Midstream Finance Corp., the Guarantors named therein and the Initial Purchasers named therein (Incorporated herein by reference to Exhibit 4.2 to SMLP's Current Report on Form 8-K dated June 17, 2013 (Commission File No. 001-35666))
10.5	Joinder Agreement, dated as of June 4, 2013, by and among Summit Midstream Holdings, LLC, The Royal Bank of Scotland plc, as Administrative Agent, and the lenders party thereto (Incorporated herein by reference to Exhibit 10.2 to SMLP's Current Report on Form 8-K dated June 5, 2013 (Commission File No. 001-35666))
10.6	Second Amended and Restated Credit Agreement dated as of November 1, 2013 (Incorporated herein by reference to Exhibit 10.6 to SMLP's 2013 Annual Report on Form 10-K dated March 10, 2014 (Commission File No. 001-35666))
10.7	Amended and Restated Guarantee and Collateral Agreement dated as of November 1, 2013 (Incorporated herein by reference to Exhibit 10.7 to SMLP's 2013 Annual Report on Form 10-K dated March 10, 2014 (Commission File No. 001-35666))
10.8	First Amendment to the Second Amended and Restated Credit Agreement and Amended and Restated Guarantee and Collateral Agreement dated as of October 15, 2015 by and between Summit Midstream Holdings, LLC, each of the guarantors parties thereto, Wells Fargo Bank, National Association and the Lenders party thereto.
10.9	Base Indenture, dated as of July 15, 2014, by and among Summit Midstream Holdings, LLC, Summit Midstream Finance Corp. and U.S. Bank National Association (Incorporated herein by reference to Exhibit 4.1 to SMLP's Current Report on Form 8-K dated July 15, 2014 (Commission File No. 001-35666))
10.10	First Supplemental Indenture, dated as of July 15, 2014, by and among Summit Midstream Holdings, LLC, Summit Midstream Finance Corp., the Guarantors party thereto and U.S. Bank National Association (including form of the 5½% senior notes due 2022) (Incorporated herein by reference to Exhibit 4.2 to SMLP's Current Report on Form 8-K dated July 15, 2014 (Commission File No. 001-35666))
10.11	Equity Distribution Agreement, dated June 12, 2015, among the Partnership, the General Partner, the Operating Company, Citigroup Global Markets Inc., Deutsche Bank Securities Inc. and RBC

	Capital Markets, LLC. (Incorporated herein by reference to Exhibit 1.1 to SMLP's Current Report on Form 8-K dated June 12, 2015 (Commission File No. 001-35666))
10.12	Contribution, Conveyance and Assumption Agreement, dated as of October 3, 2012, by and among Summit Midstream GP, LLC, Summit Midstream Partners, LP, Summit Midstream Holdings, LLC and Summit Midstream Partners, LLC (Incorporated herein by reference to Exhibit 10.1 to SMLP's Current Report on Form 8-K dated October 4, 2012 (Commission File No. 001-35666))
10.13	Contribution, Conveyance and Assumption Agreement, dated as of June 4, 2013, by and among Summit Midstream Partners Holdings, LLC, Bison Midstream, LLC and Summit Midstream Partners, LP (Incorporated herein by reference to Exhibit 10.1 to SMLP's Current Report on Form 8-K dated June 5, 2013 (Commission File No. 001-35666))

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10.14	†	Purchase and Sale Agreement dated as of June 4, 2013 by and between MarkWest Liberty Midstream & Resources, L.L.C. and Summit Midstream Partners, LP (Incorporated herein by reference to Exhibit 10.3 to SMLP's Amendment No. 1 to its Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2013 dated October 4, 2013 (Commission File No. 333-183466))
10.15		Purchase and Sale Agreement among Summit Midstream Partners Holdings, LLC, Red Rock Gathering Company, LLC and Summit Midstream Partners, LP dated as of March 8, 2014 (Incorporated herein by reference to Exhibit 10.1 to SMLP's Current Report on Form 8-K filed March 10, 2014 (Commission File No. 001-35666))
10.16		Contribution Agreement among Summit Midstream Partners Holdings, LLC, Polar Midstream, LLC, Epping Transmission Company, LLC and Summit Midstream Partners, LP dated as of May 6, 2015 (Incorporated herein by reference to Exhibit 10.1 to SMLP's Current Report on Form 8-K dated May 6, 2015 (Commission File No. 001-35666))
10.17	†	Amended and Restated Natural Gas Gathering Agreement, dated August 1, 2010, by and between DFW Midstream Services LLC, Chesapeake Energy Marketing, Inc., and Chesapeake Exploration, LLC (Incorporated herein by reference to Exhibit 10.6 to SMLP's Amendment No. 1 to its Form S-1 Registration Statement dated September 14, 2012 (Commission File No. 333-183466))
10.18	†	Amended and Restated Natural Gas Gathering Agreement, dated December 1, 2011, by and between DFW Midstream Services LLC and Carrizo Oil & Gas, Inc. (Incorporated herein by reference to Exhibit 10.7 to SMLP's Amendment No. 1 to its Form S-1 Registration Statement dated September 14, 2012 (Commission File No. 333-183466))
10.19	†	Second Amended and Restated Gas Gathering Agreement, dated November 1, 2010, by and between Willams Production RMT Company LLC and Encana Oil & Gas (USA) Inc. (Incorporated herein by reference to Exhibit 10.8 to SMLP's Amendment No. 1 to its Form S-1 Registration Statement dated September 14, 2012 (Commission File No. 333-183466))
10.20	†	Future Development Gas Gathering Agreement, dated October 1, 2011, by and between Encana Oil & Gas (USA) Inc., Grand River Gathering, LLC, and Summit Midstream Partners, LLC (Incorporated herein by reference to Exhibit 10.9 to SMLP's Amendment No. 1 to its Form S-1 Registration Statement dated September 14, 2012 (Commission File No. 333-183466))
10.21	†	Mamm Creek Gas Gathering Agreement, dated October 1, 2011, by and between Encana Oil & Gas (USA) Inc., Grand River Gathering, LLC, and Summit Midstream Partners, LLC (Incorporated herein by reference to Exhibit 10.10 to SMLP's Amendment No. 1 to its Form S-1 Registration Statement dated September 14, 2012 (Commission File No. 333-183466))
10.22	†	Gas Purchase Agreement dated as of December 20, 2010 by and between Bear Tracker Energy, LLC., and EOG Resources, Inc. (Incorporated herein by reference to Exhibit 10.1 to SMLP's Amendment No. 1 to its Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2013 dated October 4, 2013 (Commission File No. 333-183466))
10.23	†	Amended and Restated Gas Gathering and Compression Agreement dated as of November 4, 2013 by and between Mountaineer Midstream Company, LLC and Antero Resources Corporation (Incorporated herein by reference to Exhibit 10.16 to SMLP's 2013 Annual Report on Form 10-K dated March 10, 2014 (Commission File No. 001-35666))
10.24	*	Second Amended and Restated Employment Agreement, dated July 20, 2015, and effective August 13, 2015, by and between Summit Midstream Partners, LLC and Steve Newby (Incorporated herein by reference to Exhibit 10.1 to SMLP's Form 8-K dated July 24, 2015 (Commission File No. 001-35666))
10.25	*	Second Amended and Restated Employment Agreement, dated October 16, 2015, by and between Summit Midstream Partners, LLC and Matthew Harrison (Incorporated herein by reference to Exhibit 10.1 to SMLP's Current Report on Form 8-K dated October 20, 2015 (Commission File

		No. 001-35666))
10.26	*	Employment Agreement, dated January 18, 2014, by and between Summit Midstream Partners, LLC and Brock M. Degeyter (Incorporated herein by reference to Exhibit 10.1 to SMLP's Current Report on Form 8-K dated January 23, 2014 (Commission File No. 333-183466))
10.27	*	Amended and Restated Employment Agreement, dated March 1, 2015, by and between Summit Midstream Partners, LLC and Brad N. Graves (Incorporated herein by reference to Exhibit 10.1 to SMLP's Current Report on Form 8-K dated March 4, 2015 (Commission File No. 001-35666))
10.28	*	Employment Agreement, effective December 1, 2015, by and between Summit Midstream Partners, LLC and Leonard Mallett (Incorporated herein by reference to Exhibit 10.1 to SMLP's Current Report on Form 8-K filed November 17, 2015 (Commission File No. 001-35666))

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10.29	*	Summit Midstream Partners, LP 2012 Long-Term Incentive Plan (Incorporated herein by reference to Exhibit 10.2 to SMLP's Current Report on Form 8-K dated October 4, 2012 (Commission File No. 001-35666))
10.30		Summit Midstream Partners, LP 2012 Long-Term Incentive Plan Phantom Unit Agreement (Incorporated herein by reference to Exhibit 10.1 to SMLP's Current Report on Form 8-K dated March 17, 2014 (Commission File No. 001-35666))
10.31		Form of Director Unit Award Agreement (Incorporated herein by reference to Exhibit 10.3 to SMLP's Current Report on Form 8-K dated October 4, 2012 (Commission File No. 001-35666))
10.32	*	Award Agreement by and between Summit Midstream GP, LLC, Summit Midstream Partners, LP and Leonard Mallett (Incorporated herein by reference to Exhibit 10.2 to SMLP's Current Report on Form 8-K filed November 17, 2015 (Commission File No. 001-35666))
10.33		Summit Midstream Partners, LLC Deferred Compensation Plan dated as of July 1, 2013 (Incorporated herein by reference to Exhibit 4.3 to SMLP's Form S-8 Registration Statement dated June 28, 2013 (Commission File No. 333-189684))
12.1		Ratio of Earnings to Fixed Charges
21.1		List of Subsidiaries
23.1		Consent of Deloitte & Touche LLP
31.1		Rule 13a-14(a)/15d-14(a) Certification, executed by Steven J. Newby, President, Chief Executive Officer and Director
31.2		Rule 13a-14(a)/15d-14(a) Certification, executed by Matthew S. Harrison, Executive Vice President and Chief Financial Officer
32.1		Certifications required by Rule 13a-14(b) or Rule 15d-14(b) and Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350), executed by Steven J. Newby, President, Chief Executive Officer and Director, and Matthew S. Harrison, Executive Vice President and Chief Financial Officer
101.INS	**	XBRL Instance Document (1)
101.SCH	**	XBRL Taxonomy Extension Schema
101.CAL	**	XBRL Taxonomy Extension Calculation Linkbase
101.DEF	**	XBRL Taxonomy Extension Definition Linkbase
101.LAB	**	XBRL Taxonomy Extension Label Linkbase
101.PRE	**	XBRL Taxonomy Extension Presentation Linkbase

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

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

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

(1) Includes the following materials contained in this Annual Report on Form 10-K for the year ended December 31, 2015, formatted in XBRL: (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Operations, (iii) Consolidated Statements of Partners' Capital, (iv) Consolidated Statements of Cash Flows, and (v) Notes to Consolidated Financial Statements.

(c) Financial Statement Schedules

Not applicable.

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SIGNATURES

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

Summit Midstream Partners, LP
(Registrant)

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

February 26, 2016

/s/ Matthew S. Harrison
Matthew S. Harrison, Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)

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

Signature	Title	Date
/s/ Steven J. Newby Steven J. Newby	Director, President and Chief Executive Officer (Principal Executive Officer)	February 26, 2016
/s/ Matthew S. Harrison Matthew S. Harrison	Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	February 26, 2016
/s/ Thomas K. Lane Thomas K. Lane	Director	February 26, 2016
/s/ Christopher M. Leininger Christopher M. Leininger	Director	February 26, 2016
/s/ Curtis A. Morgan Curtis A. Morgan	Director	February 26, 2016
/s/ Jerry L. Peters Jerry L. Peters	Director	February 26, 2016
/s/ Scott A. Rogan Scott A. Rogan	Director	February 26, 2016
/s/ Jeffrey R. Spinner Jeffrey R. Spinner	Director	February 26, 2016
/s/ Susan Tomasky Susan Tomasky	Director	February 26, 2016
/s/ Robert M. Wohleber Robert M. Wohleber	Director	February 26, 2016