Summit Midstream Partners, LP
Form 10-K
February 29, 2016
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K
(Mark One)
[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 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	45-5200503
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1790 Hughes Landing Blvd, Suite 500 The Woodlands, TX	77380
(Address of principal executive offices)	(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 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

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(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

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(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

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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.

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

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

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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.

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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

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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

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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

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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

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, 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				
	Year ended December 31,			Percentage Change	
	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)

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(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	