# UNITED STATES
# SECURITIES AND EXCHANGE COMMISSION
**Washington, D.C. 20549**
# FORM 8-K

## CURRENT REPORT

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

Date of Report (Date of earliest event reported): June 6, 2016

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

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

**1790 Hughes Landing Blvd**
**Suite 500**
**The Woodlands, TX 77380**
(Address of principal executive offices) (Zip Code)

Registrants’ telephone number, including area code: **(832) 413-4770**

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

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

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

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

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

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

## Item 8.01 Other Events.

Summit Midstream Partners, LP ("SMLP" or the “Partnership”) is filing this Current Report on Form 8-K to update certain items in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2015 (the "2015 Annual Report"). On March 3, 2016, SMLP closed on its acquisition of substantially all of (i) the issued and outstanding membership interests of Summit Midstream Utica, LLC ("Summit Utica"), Meadowlark Midstream Company, LLC (“Meadowlark Midstream”) and Tioga Midstream, LLC ("Tioga Midstream," and collectively with Summit Utica and Meadowlark Midstream, the "Contributed Entities"), each a limited liability company and indirect wholly owned subsidiary of Summit Midstream Partners Holdings, LLC ("SMP Holdings") and (ii) SMP Holdings’ 40% ownership interest in each of Ohio Gathering Company, L.L.C. ("Ohio Gathering") and Ohio Condensate Company, L.L.C. ("Ohio Condensate" and collectively with Ohio Gathering and the Contributed Entities, the “2016 Drop Down Assets”)(the “2016 Drop Down”). Summit Investments, as the ultimate owner of SMLP's general partner, controls SMLP and has the right to appoint the entire board of directors of its general partner. As such, the 2016 Drop Down was deemed a transaction among entities under common control and a change in reporting entity. Transfers of net assets or exchanges of membership interests between entities under common control are accounted for as if the transfer occurred at the beginning of the period, and prior periods are retrospectively adjusted to furnish comparative information similar to a pooling of interests.

In addition, this Current Report on Form 8-K reflects the Partnership's retrospective adoption of Accounting Standards Update ("ASU") No. 2015-03 Interest—Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs ("ASU 2015-03"). In accordance with the requirements of the Securities and Exchange Commission (the "SEC"), we are required to revise previously issued financial statements using the recognition guidance under ASU 2015-03 for each of the years presented in the 2015 Annual Report, if those financial statements are incorporated by reference in certain subsequent filings with the SEC made under the Securities Act of 1933, as amended, even though those financial statements relate to periods prior to the adoption of ASU 2015-03. As a result, these financial statements reflect the retrospective reclassification of $9.2 million of deferred loan costs from other noncurrent assets to long-term debt at December 31, 2015 and $10.8 million at December 31, 2014. This ASU had no impact on interest expense, net income or loss, earnings or loss per unit or partners' capital. The revision of the previously issued 2015 Annual Report is being made in accordance with applicable accounting rules and should not be read as a restatement of the 2015 Annual Report.

The following items of the 2015 Annual Report are being retrospectively adjusted to reflect the 2016 Drop Down and the Partnership's interest in the financial results of the 2016 Drop Down Assets for all periods during which common control existed as well as the adoption of ASU 2015-03:

- Item 1. Business;
- Item 2. Properties;
- Item 6. Selected Financial Data;
- Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations;
- Item 8. Financial Statements and Supplementary Data;
- Exhibit 12.1 Ratio of Earnings to Fixed Charges; and
- Exhibit 21.1 List of Subsidiaries.

These items replace the same items filed in the Partnership’s 2015 Annual Report as filed with the SEC on February 29, 2016.

The information in this Current Report on Form 8-K should be read in conjunction with the other information included (but not replaced as described above) in the 2015 Annual Report. More current information is contained in the Partnership's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2016 and the Partnership's other filings with the SEC.

### Item 9.01 Financial Statements and Exhibits.

(d) Exhibits.

| Exhibit number | | Description |
|---|---|---|
| 12.1 | | Ratio of Earnings to Fixed Charges |
| 21.1 | | List of Subsidiaries |
| 23.1 | | Consent of Deloitte & Touche LLP |
| 99.1 | | Updated 2015 Annual Report on Form 10-K - Item 1. Business. |
| 99.2 | | Updated 2015 Annual Report on Form 10-K - Item 2. Properties. |
| 99.3 | | Updated 2015 Annual Report on Form 10-K - Item 6. Selected Financial Data. |
| 99.4 | | Updated 2015 Annual Report on Form 10-K - Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations. |
| 99.5 | | Updated 2015 Annual Report on Form 10-K - Item 8. Financial Statements and Supplementary Data. |
| 101.INS | * | XBRL Instance Document (1) |
| 101.SCH | * | XBRL Taxonomy Extension Schema |
| 101.CAL | * | XBRL Taxonomy Extension Calculation Linkbase |
| 101.DEF | * | XBRL Taxonomy Extension Definition Linkbase |
| 101.LAB | * | XBRL Taxonomy Extension Label Linkbase |
| 101.PRE | * | XBRL Taxonomy Extension Presentation Linkbase |

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

(1) Includes the following materials for the year ended December 31, 2015, formatted in XBRL: (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Operations, (iii) Consolidated Statements of Partners' Capital and Membership Interests, (iv) Consolidated Statements of Cash Flows, and (v) Notes to Consolidated Financial Statements.

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

| | |
|---|---|
| | Summit Midstream Partners, LP |
| | (Registrant) |
| | By: Summit Midstream GP, LLC (its general partner) |
| June 6, 2016 | */s/ Matthew S. Harrison* |
| | Matthew S. Harrison, Executive Vice President and Chief Financial Officer |

## EXHIBIT INDEX

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**SUMMIT MIDSTREAM PARTNERS, LP**
**RATIO OF EARNINGS TO FIXED CHARGES**

The following table sets forth our ratio of earnings to fixed charges for the periods indicated on a consolidated historical basis. For purposes of computing the ratio of earnings to fixed charges, "earnings" are defined as income or loss before income taxes before adjustment for income or loss from equity method investees plus fixed charges and distributions from equity method investees less capitalized interest. "Fixed charges" consist of interest expensed and capitalized, amortization of deferred loan costs and an estimate of interest within rent expense.

| | Year ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2015 (1) | 2014 (2) | 2013 | 2012 | 2011 |
| | (Dollars in thousands) | | | | |
| **Earnings:** | | | | | |
| (Loss) income before income taxes before adjustment for income or loss from equity method investees | $ (216,268) | $ (29,802) | $ 47,737 | $ 43,679 | $ 38,646 |
| Add (deduct): | | | | | |
| Fixed charges | 63,262 | 53,859 | 28,543 | 15,794 | 6,579 |
| Distributions from equity method investees | 34,641 | 2,992 | — | — | — |
| Capitalized interest | (3,372) | (4,646) | (6,690) | (2,784) | (3,362) |
| Total earnings | $ (121,737) | $ 22,403 | $ 69,590 | $ 56,689 | $ 41,863 |
| **Fixed Charges:** | | | | | |
| Interest expense | $ 59,092 | $ 48,586 | $ 21,314 | $ 12,766 | $ 3,054 |
| Capitalized interest | 3,372 | 4,646 | 6,690 | 2,784 | 3,362 |
| Estimate of interest within rent expense | 798 | 627 | 539 | 244 | 163 |
| Total fixed charges | $ 63,262 | $ 53,859 | $ 28,543 | $ 15,794 | $ 6,579 |
| **Ratio of earnings to fixed charges** | — | 0.42x | 2.44x | 3.59x | 6.36x |

(1) The ratio of earnings to fixed charges was negative for the year ended December 31, 2015. To achieve a ratio of earnings to fixed charges of 1:1, we would have had to generate an additional $185.0 million of earnings for the year ended December 31, 2015. Loss before income taxes for the year ended December 31, 2015 included $248.9 million of goodwill impairments.
(2) The ratio of earnings to fixed charges was less than 1:1 for the year ended December 31, 2014. To achieve a ratio of earnings to fixed charges of 1:1, we would have had to generate an additional $31.5 million of earnings for the year ended December 31, 2014. Loss before income taxes for the year ended December 31, 2014 included a goodwill impairment of $54.2 million.

**SUMMIT MIDSTREAM PARTNERS, LP**
**LIST OF SUBSIDIARIES**

| Name | State or other jurisdiction of incorporation or organization |
|---|---|
| Summit Midstream Holdings, LLC | Delaware |
| Grand River Gathering, LLC | Delaware |
| DFW Midstream Services LLC | Delaware |
| Bison Midstream, LLC | Delaware |
| Summit Midstream Finance Corp. | Delaware |
| Red Rock Gathering Company, LLC | Delaware |
| Polar Midstream, LLC | Delaware |
| Epping Transmission Company, LLC | Delaware |
| Summit Midstream Utica, LLC | Delaware |
| Meadowlark Midstream Company, LLC | Delaware |
| Tioga Midstream, LLC | Delaware |
| Summit Midstream OpCo, LP | Delaware |
| Summit Midstream OpCo GP, LLC | Delaware |

## CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-197311 and 333-191493 on Form S-3 and Nos. 333-184214 and 333-189684 on Form S-8 of our report dated February 26, 2016 (June 6, 2016 as to the effects of the 2016 Drop Down as described in Notes 1 and 16, and the retrospective application of the change in accounting policy for presentation of debt issuance costs in Note 1), relating to the consolidated financial statements of Summit Midstream Partners, LP and subsidiaries (the “Partnership”) (which report expresses an unqualified opinion and includes an explanatory paragraph regarding the retrospective adjustment for the acquisition of Summit Midstream Utica, LLC, Meadowlark Midstream Company, LLC, Tioga Midstream, LLC, and SMP Holdings’ 40.0% ownership interest in each of Ohio Gathering Company, L.L.C. and Ohio Condensate Company, L.L.C. from Summit Midstream Partners Holdings, LLC which was accounted for as a combination of entities under common control), appearing in this Current Report on Form 8-K dated June 6, 2016 of Summit Midstream Partners, LP.

/s/ DELOITTE & TOUCHE LLP
Atlanta, Georgia

June 6, 2016

## 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.

Our gathering systems and the unconventional resource basins in which they operate are as follows:

- Summit Midstream Utica, LLC ("Summit Utica"), a natural gas gathering system operating in the Appalachian Basin, which includes the Utica and Point Pleasant shale formations in southeastern Ohio;
- Bison Midstream, LLC ("Bison Midstream"), an associated natural gas gathering system, operating in the Williston Basin, which includes the Bakken and Three Forks shale formations in northwestern North Dakota;
- the Polar and Divide system ("Polar and Divide"), crude oil and produced water gathering systems and transmission pipelines located in the Williston Basin, which includes the Bakken and Three Forks shale formations in northwestern North Dakota;
- Tioga Midstream, LLC ("Tioga Midstream"), crude oil, produced water and associated natural gas gathering systems, operating in the Williston Basin, which includes the Bakken and Three Forks shale formations in northwestern North Dakota;
- Grand River Gathering, LLC ("Grand River"), a natural gas gathering and processing system located in the Piceance Basin, which includes the Mesaverde formation and the Mancos and Niobrara shale formations in western Colorado and eastern Utah;
- the Niobrara Gathering and Processing system ("Niobrara G&P"), an associated natural gas gathering and processing system operating in the DJ Basin, which includes the Niobrara shale formation in northeastern Colorado;
- DFW Midstream Services LLC ("DFW Midstream"), a natural gas gathering system, operating in the Fort Worth Basin, which includes the Barnett Shale formation in north-central Texas; and
- the Mountaineer Midstream system ("Mountaineer Midstream"), a natural gas gathering system, operating in the Appalachian Basin, which includes the Marcellus Shale formation in northern West Virginia.

We believe that our gathering systems are well positioned to capture volumes from producer activity in these regions in the future. We also have ownership interests in Ohio Gathering Company, L.L.C. and Ohio Condensate

Company, L.L.C. (collectively, "Ohio Gathering"). Ohio Gathering operates a natural gas gathering system and a condensate stabilization facility in the Appalachian Basin, which includes the Utica and Point Pleasant shale formations in southeastern Ohio. For additional information, see Note 7 to the consolidated financial statements.

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.

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:

- XTO Energy, Inc. ("XTO"), the anchor customer for Summit Utica;
- EOG Resources, Inc ("EOG") and Oasis Petroleum, Inc. ("Oasis"), the anchor customers for Bison Midstream;
- Whiting Petroleum Corp. ("Whiting") and SM Energy Company ("SM Energy"), the anchor customers for Polar and Divide;
- Hess Corp. ("Hess"), the anchor customer for Tioga Midstream;
- Encana Corporation ("Encana") and WPX Energy, Inc. ("WPX"), the anchor customers for Grand River;
- EOG, the anchor customer for Niobrara G&P;
- Chesapeake Energy Corporation ("Chesapeake"), the anchor customer for DFW Midstream; and
- Antero Resources Corp. ("Antero"), the anchor customer for Mountaineer Midstream.

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 10 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 third parties. In addition, we may participate in asset acquisitions with Summit Investments, although (i) Summit Investments has no obligation to us to offer any assets that it may acquire or participate in any asset acquisitions that we may make and (ii) we have no obligation to acquire those assets. 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

As of December 31, 2015, our reportable segments and their respective gathering systems were:

- the Utica Shale, which includes Ohio Gathering and Summit Utica;
- the Williston Basin, which includes Bison Midstream, Polar and Divide and Tioga Midstream;
- the Piceance/DJ Basins, which includes Grand River and Niobrara G&P;
- the Barnett Shale, which includes DFW Midstream; and
- the Marcellus Shale, which includes Mountaineer Midstream;

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 our reportable segments consist of gathering systems and related property, plant and equipment with the exception of the Utica Shale reportable segment. The primary asset of the Utica Shale reportable segment is its ownership interest in Ohio Gathering.

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 1,498 million cubic feet per day ("MMcf/d") and crude oil and produced water volume throughput averaged 67.7 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 2.0 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 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 8.5 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 of February 16, 2016, Summit Investments had acquired 151,160 common units and Energy Capital Partners had acquired 2,184,186 common units under the Purchase Program.

***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, 11 and 16 to the consolidated financial statements.

### Recent Developments

***2016 Drop Down.*** On February 25, 2016, the Partnership and Summit Midstream Partners Holdings, LLC (“SMP Holdings”), a wholly owned subsidiary of Summit Investments, entered into a contribution agreement (the "Contribution Agreement") pursuant to which SMP Holdings agreed to contribute to the Partnership substantially all of (i) the issued and outstanding membership interests of Summit Utica, Meadowlark Midstream Company, LLC ("Meadowlark Midstream") and Tioga Midstream (collectively with Summit Utica and Meadowlark Midstream, the "Contributed Entities"), each a limited liability company and indirect wholly owned subsidiary of SMP Holdings and (ii) SMP Holdings’ 40.0% ownership interest in Ohio Gathering (collectively with the Contributed Entities, the “2016 Drop Down Assets”)(the “2016 Drop Down”). Meadowlark Midstream is the legal entity which owns (i) certain crude oil and produced water gathering pipelines, which are managed and reported as part of the Polar and Divide system subsequent to the 2016 Drop Down and (ii) Niobrara G&P. The 2016 Drop Down closed on March 3, 2016 (the "Initial Close"). Upon Initial Close, the Partnership held a 99.0% ownership interest in the 2016 Drop Down Assets and Summit Investments held a 1.0% noncontrolling interest.

***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. We believe that our focus on fee-based revenues with minimal direct commodity exposure is essential to maintaining stable cash flows.
- ***Capitalizing on organic growth opportunities to maximize throughput on our existing systems.*** We intend to continue to leverage our management team's expertise in constructing, developing and optimizing our midstream 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, Barnett and Utica shale plays and the Piceance and DJ basins 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/or 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 five 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 $1.27 billion of total indebtedness (including $332.5 million of debt that was allocated to us in connection with the accounting recognition for the 2016 Drop Down, see Notes 1, 2 and 9 to the consolidated financial statements) 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.

## Our Midstream Assets

Our midstream assets currently consist of the following gathering systems:

- Summit Utica in southeastern Ohio;
- Bison Midstream in northwestern North Dakota;
- Polar and Divide in northwestern North Dakota;
- Tioga Midstream in northwestern North Dakota;
- Grand River in western Colorado and eastern Utah;
- Niobrara G&P in northeastern Colorado;

- DFW Midstream in north-central Texas; and
- Mountaineer Midstream in northern West Virginia.

We also have ownership interests in Ohio Gathering, which operates in southeastern Ohio. For additional information, see Note 7 to the consolidated financial statements.

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 8.5 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 8 to the consolidated financial statements.

## Utica Shale

***Ohio Gathering.*** Ohio Gathering comprises a natural gas gathering system and condensate stabilization facility located in the core of the Utica Shale in southeastern Ohio that 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 natural gas liquids ("NGLs") production from the Utica and Point Pleasant shale formations across Harrison, Guernsey, Belmont, Noble and Monroe counties in southeastern Ohio. Gulfport Energy Corporation ("Gulfport") is the anchor for Ohio Gathering. 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.

The condensate stabilization 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. As the largest stabilization facility in the Utica Shale Play, this facility will ultimately serve as the origination point for MPLX's Cornerstone Pipeline which will deliver condensate to Marathon Petroleum's refinery in Canton, Ohio.

Non-affiliated owners have a 60.0% ownership interest in Ohio Gathering. For additional information, see Note 7 to the consolidated financial statements.

***Summit Utica.*** The Utica Shale reportable segment also includes Summit Utica. Summit Utica is a natural gas gathering system located in the Appalachian Basin in southeastern Ohio serving producers targeting the dry-gas window of the Utica and Point Pleasant shale formations. The system is currently in service and under development and had throughput capacity of 300 MMcf/d as of December 31, 2015. The Summit Utica system gathers and delivers natural gas, primarily under long-term, fee-based gathering agreements which include acreage dedications. XTO serves as the anchor customer on the system. The system interconnects with Energy Transfer Partners, L.P.'s Utica Ohio River Pipeline.

## Williston Basin

The following table provides operating information regarding our Williston Basin reportable segment as of December 31, 2015.

| | Throughput capacity – liquids (Mbbl/d) | Throughput capacity – natural gas (MMcf/d) | Average daily MVCs through 2020 (MMcf/d) (1) | Remaining MVCs (Bcf) (1) | Weighted-average remaining contract life (Years) (1)(2) |
|---|---|---|---|---|---|
| Williston Basin - natural gas (3) | n/a | 46 | 8 | 14 | 4.6 |
| Williston Basin - liquids (3) | 160 | n/a | | | |

(1) Contract terms related to liquids MVCs are excluded for confidentiality purposes.
(2) Weighted average based on total remaining MVC (total remaining MVCs multiplied by average rate).
(3) Prior periods have been recast to include the incremental historical volumes from the 2016 Drop Down.

AMIs for the Williston Basin reportable segment total more than 1.2 million acres in the aggregate.

***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.

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. In connection with the 2016 Drop Down, we also acquired certain crude oil and produced water gathering pipelines. We refer to these assets, 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 crude oil and produced water midstream services for the Williston Basin reportable segment.

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.

***Tioga Midstream.*** The Tioga Midstream gathering system 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 Midstream gathering system are provided pursuant to long-term, fee-based gathering agreements with 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 Midstream system is delivered to downstream pipelines and disposal wells (for produced water) that are owned and operated by Hess.

## Piceance/DJ Basins

The following table provides operating information regarding our Piceance/DJ Basins reportable segment as of December 31, 2015.

| | Throughput capacity (MMcf/d) | Average daily MVCs through 2020 (MMcf/d) | Remaining MVCs (Bcf) | Weighted-average remaining contract life (Years) (1) |
|---|---|---|---|---|
| Piceance/DJ Basins | 1,186 | 684 | 1,880 | 8.9 |

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

AMIs for the Piceance/DJ Basins reportable segment total more than 700,000 acres in the aggregate.

***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/DJ Basin reportable segment.

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.

***Niobrara G&P.*** The Niobrara G&P system comprises a low-pressure and high-pressure associated natural gas 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. Residue gas is delivered to the Colorado Interstate Gas pipeline and processed NGLs are delivered to the Overland Pass Pipeline.

## Barnett Shale

The following table provides operating information regarding our Barnett Shale reportable segment as of December 31, 2015.

| | Throughput capacity (MMcf/d) | Average daily MVCs through 2020 (MMcf/d) | Remaining MVCs (Bcf) | Weighted-average remaining contract life (Years) (1) |
|---|---|---|---|---|
| Barnett Shale | 480 | 68 | 120 | 3.8 |

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

AMIs for the Barnett Shale reportable segment total approximately 108,300 acres.

***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.

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.

### Marcellus Shale

The following table provides operating information regarding our Marcellus Shale reportable segment as of December 31, 2015.

| | Throughput capacity (MMcf/d) |
|---|---|
| Marcellus Shale (1) | 1,050 |

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

***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-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.

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.

## 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 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 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
- enjoining the operations of facilities deemed to be in non-compliance with permits or permit requirements issued pursuant to or imposed by such environmental laws and regulations.

Failure to comply with these laws and regulations may trigger administrative, civil and criminal enforcement measures, including the assessment of monetary penalties. Certain environmental statutes impose strict joint and several liability for costs required to clean up and restore sites where substances, hydrocarbons or wastes have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment.

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

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

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

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

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

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

In April 2012, the EPA finalized rules that establish new air emission reporting, monitoring, and control requirements for oil and natural gas production and natural gas processing operations. Specifically, the EPA's rule package included New Source Performance Standards ("NSPS") to address emissions of sulfur dioxide and volatile organic compounds ("VOCs") from a number of sources that were previously not regulated in the crude oil and natural gas industry. Through the same rulemaking, the EPA revised several existing regulations to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The rules establish specific new requirements regarding emissions from compressors, pneumatic controllers, dehydrators, storage tanks and other production equipment. In addition, the rules establish new leak detection requirements for natural gas processing plants at 500 ppm. These rules required a number of modifications to our operations, including the installation of new equipment to control emissions from VOC emitting tanks at initial startup. To date, compliance with such rules has not resulted in significant costs.

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

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

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

***Water Discharges.*** The Clean Water Act, and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into regulated waters, which impacts our ability to conduct construction activities in waters and wetlands. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System program prohibit the discharge of pollutants and chemicals. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. These permits require us to control storm water runoff from some of our facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

***Oil Pollution Act.*** The Oil Pollution Control Act (the "OPA") requires the preparation of a Spill Prevention Control and Countermeasure (“SPCC”) plan for facilities engaged in drilling, producing, gathering, storing, processing, refining, transferring, distributing, using, or consuming oil and oil products, and which due to their location, could reasonably be expected to discharge oil in harmful quantities into or upon the navigable waters of the United States. The owner or operator of an SPCC-regulated facility is required to prepare a written, site-specific spill prevention plan, which details how a facility's operations comply with the requirements. To be in compliance, the facility's SPCC plan must satisfy all of the applicable requirements for drainage, bulk storage tanks, tank car and truck loading and unloading, transfer operations (intrafacility piping), inspections and records, security, and training. Certain of our facilities are classified as SPCC-regulated facilities. We believe that they are in substantial compliance with all applicable requirements of OPA.

***Hydraulic Fracturing.*** Hydraulic fracturing is an important and increasingly common practice that is used to stimulate production of natural gas and/or crude oil from dense subsurface rock formations, and is primarily presently regulated by state agencies. However, Congress has in the past and may in the future consider legislation 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 326 people who provide direct, full-time support to our operations. None of our employees are covered by collective bargaining agreements, and we have never experienced any business interruption as a result of any labor disputes.

***Availability of Reports.*** 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 2. Properties.

Our gathering systems, the unconventional resource basins in which they operate and the reportable segments in which they are reported are as follows:

- Summit Utica, a natural gas gathering system operating in the Appalachian Basin, which includes the Utica and Point Pleasant shale formations in southeastern Ohio, is included in the Utica Shale reportable segment;
- Bison Midstream, an associated natural gas gathering system operating in the Williston Basin, which includes the Bakken and Three Forks shale formations in northwestern North Dakota, is included in the Williston Basin reportable segment;
- Polar and Divide, crude oil and produced water gathering systems and transmission pipelines operating in the Williston Basin, which includes the Bakken and Three Forks shale formations in northwestern North Dakota, is included in the Williston Basin reportable segment;
- Tioga Midstream, crude oil, produced water and associated natural gas gathering systems operating in the Williston Basin, which includes the Bakken and Three Forks shale formations in northwestern North Dakota, is included in the Williston Basin reportable segment;
- Grand River, a natural gas gathering and processing system operating in the Piceance Basin, which includes the Mesaverde formation and the Mancos and Niobrara shale formations in western Colorado and eastern Utah, is included in the Piceance/DJ Basins reportable segment;
- Niobrara G&P, an associated natural gas gathering and processing system operating in the DJ Basin, which includes the Niobrara shale formation in northeastern Colorado, is included in the Piceance/DJ Basins reportable segment;
- DFW Midstream, a natural gas gathering system operating in the Fort Worth Basin, which includes the Barnett Shale formation in north-central Texas, is included in the Barnett Shale reportable segment; and
- Mountaineer Midstream, a natural gas gathering system operating in the Appalachian Basin, which includes the Marcellus Shale formation in northern West Virginia, is included in the Marcellus Shale reportable segment.

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 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.

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) Summit Utica since December 2014, (ii) Tioga Midstream since April 2014, (iii) Ohio Gathering since January 2014, (iv) Bison Midstream, Polar and Divide, and Meadowlark Midstream since February 2013, (v) Mountaineer Midstream since June 2013, (vi) Red Rock Gathering since October 2012 and (vii) Legacy Grand River since October 2011. SMLP recognized its acquisitions in the "2016 Drop Down", the "Polar and Divide Drop Down", the "Bison Drop Down" and 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 and recognized for a contributed subsidiary is recognized as an addition to partners' capital, while the excess of purchase price paid and recognized over net investment is recognized as a reduction to partners' capital. Due to the common control aspect, we account for drop down transactions on an “as-if pooled” basis for the periods during which common control existed.

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 | $ 3,164,672 | $ 3,242,462 | $ 2,282,046 | $ 1,280,939 | $ 1,030,264 |
| Total long-term debt | 1,267,270 | 1,232,207 | 772,140 | 199,230 | 349,893 |
| Partners' capital | 1,747,299 | 1,830,678 | 1,395,806 | 1,028,355 | 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

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 | $ 400,557 | $ 387,169 | $ 326,160 | $ 174,423 | $ 103,552 |
| Total costs and expenses (1) | 557,735 | 369,574 | 257,114 | 117,987 | 61,864 |
| Interest expense | 59,092 | 48,586 | 21,314 | 7,340 | 1,029 |
| Affiliated interest expense | — | — | — | 5,426 | 2,025 |
| Net (loss) income | (222,228) | (47,368) | 47,008 | 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) | $ (57,838) | $ 93,890 | $ 141,310 | $ 93,302 | $ 53,363 |
| Adjusted EBITDA | 235,491 | 207,975 | 162,690 | 105,946 | 56,803 |
| Capital expenditures | 272,225 | 343,380 | 249,626 | 77,296 | 78,248 |
| Acquisition capital expenditures (2) | 288,618 | 315,872 | 458,914 | — | 589,462 |
| Distributable cash flow | 164,931 | 144,711 | 120,611 | 90,947 | 50,980 |
| Distributions declared per unit (3) | 2.285 | 2.120 | 1.795 | 0.410 | n/a |

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, the 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:



## 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 five reportable segments:

- the Utica Shale, which includes our ownership interest in Ohio Gathering and also is served by Summit Utica;
- the Williston Basin, which is served by Bison Midstream, Polar and Divide, and Tioga Midstream;
- the Piceance/DJ Basins, which is served by Grand River and Niobrara G&P;
- the Barnett Shale, which is served by DFW Midstream;
- the Marcellus Shale, which is served by Mountaineer Midstream.

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 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 are exposed to direct 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 or natural gas) 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.

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 | $ (222,228) | $ (47,368) | $ 47,008 |
| EBITDA (1) | (57,838) | 93,890 | 141,310 |
| Adjusted EBITDA (1) | 235,491 | 207,975 | 162,690 |
| Distributable cash flow (1) | 164,931 | 144,711 | 120,611 |
| | | | |
| Acquisitions of gathering systems (2) | $ 288,618 | $ 315,872 | $ 458,914 |
| Capital expenditures (3) | (272,225) | (343,380) | (249,626) |
| | | | |
| 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 | 216,000 | (136,000) | 179,770 |
| Distributions to unitholders | (152,074) | (122,224) | (90,196) |

(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 16 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, crude oil and NGL 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, Bison Midstream and Tioga 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, crude oil and NGL 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.

***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, Polar and Divide, Niobrara G&P and Tioga Midstream 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 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 9 and 11 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 to 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 five reportable segments:

- the Utica Shale, which includes our ownership interest in Ohio Gathering as well as Summit Utica;
- the Williston Basin, which includes Bison Midstream, Polar and Divide and Tioga Midstream;
- the Piceance/DJ Basins, which includes Grand River and Niobrara G&P;
- the Barnett Shale, which includes DFW Midstream;
- the Marcellus Shale, which includes Mountaineer Midstream.

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;

- 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 (i) income or loss from equity method investees, (ii) the impact of the timing of MVC shortfall payments under our gathering agreements or (iii) 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 Summit Utica since December 2014. 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 consolidated financial statements reflect the results of operations of Tioga Midstream since April 2014. 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 consolidated financial statements reflect the results of operations of Ohio Gathering since January 2014. 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 consolidated financial statements reflect the results of operations of Bison Midstream, Polar and Divide and Niobrara G&P since February 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 consolidated financial statements reflect the results of operations of Mountaineer Midstream since June 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.

***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, our senior notes and debt that was allocated to the 2016 Drop Down Assets (see Notes 2 and 9 to the consolidated financial statements).

***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 | $ 337,819 | $ 267,478 | $ 216,352 | 26 % | 24 % |
| Natural gas, NGLs and condensate sales | 42,079 | 97,094 | 88,185 | (57)% | 10 % |
| Other revenues | 20,659 | 22,597 | 21,623 | (9)% | 5 % |
| Total revenues | 400,557 | 387,169 | 326,160 | 3 % | 19 % |
| **Costs and expenses:** | | | | | |
| Cost of natural gas and NGLs | 31,398 | 72,415 | 68,037 | (57)% | 6 % |
| Operation and maintenance | 94,986 | 94,869 | 78,175 | — % | 21 % |
| General and administrative | 45,108 | 43,281 | 36,716 | 4 % | 18 % |
| Transaction costs | 1,342 | 2,985 | 2,841 | (55)% | 5 % |
| Depreciation and amortization | 105,117 | 90,878 | 71,232 | 16 % | 28 % |
| Environmental remediation | 21,800 | 5,000 | — | * | * |
| (Gain) loss on asset sales, net | (172) | 442 | 113 | * | * |
| Long-lived asset impairment | 9,305 | 5,505 | — | 69 % | * |
| Goodwill impairment | 248,851 | 54,199 | — | * | * |
| Total costs and expenses | 557,735 | 369,574 | 257,114 | 51 % | 44 % |
| Other income | 2 | 1,189 | 5 | * | * |
| Interest expense | (59,092) | (48,586) | (21,314) | 22 % | 128 % |
| (Loss) income before income taxes | (216,268) | (29,802) | 47,737 | * | * |
| Income tax benefit (expense) | 603 | (854) | (729) | * | 17 % |
| Loss from equity method investees | (6,563) | (16,712) | — | (61)% | * |
| Net (loss) income | $ (222,228) | $ (47,368) | $ 47,008 | * | * |
| | | | | | |
| **Operating Data:** | | | | | |
| Aggregate average throughput – gas (MMcf/d) | 1,498 | 1,423 | 1,139 | 5 % | 25 % |
| Aggregate average throughput rate per Mcf – gas | $ 0.47 | $ 0.47 | $ 0.50 | — % | (6)% |
| Average throughput – liquids (Mbbl/d) | 67.7 | 40.7 | 10.9 | 66 % | * |
| Average throughput rate per Bbl – liquids | $ 1.84 | $ 1.69 | $ 0.95 | 9 % | 78 % |

* 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 and Summit Utica, partially offset by volume throughput declines on Grand River.

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 and Tioga Midstream systems, new pad site connections and producers' ongoing drilling activity.

***Revenues.*** For the year ended December 31, 2015, total revenues increased $13.4 million primarily reflecting:

- the recognition in 2015 of previously deferred revenue at Grand River (see Note 8 to the consolidated financial statements).

- an increase in gathering services and related fees for the Polar and Divide, Mountaineer Midstream, Summit Utica and Tioga 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 $61.0 million, or 19%, primarily reflecting:

- overall growth at Grand River 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.
- gathering services and related fees at Tioga Midstream, which was brought into service in November 2014.
- overall growth at Bison Midstream primarily due to higher volume throughput.
- an overall decline in DFW Midstream revenues largely due to lower volume throughput.

<u>Gathering Services and Related Fees</u>. 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, Mountaineer Midstream, Summit Utica and Tioga Midstream systems.

The aggregate average throughput rate for natural gas was flat at $0.47/Mcf during the years ended December 31, 2015 and 2014, primarily as a result of Tioga Midstream's contribution, partially offset by 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 $1.69/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; a full year of operations under SMLP's ownership as well as our build out of the Mountaineer Midstream system and the partial year of operations for Tioga Midstream. 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 $0.47/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 $1.69/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.

<u>Natural Gas, NGLs and Condensate Sales</u>. The decrease in natural gas, NGLs and condensate sales for the year ended December 31, 2015 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.

The increase in natural gas, NGLs and condensate sales for the year ended December 31, 2014 was primarily a result of increased volumes under percent-of-proceeds arrangements at Bison Midstream, partially offset by declining commodity prices.

***Costs and Expenses.*** Total costs and expenses increased $188.2 million, or 51%, 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.
- a full year of operations for Summit Utica and Tioga Midstream.
- an environmental remediation accrual for assets contributed to Polar and Divide in connection with the 2016 Drop Down.
- 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 $112.5 million, or 44%, 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.
- a partial year of operations for Tioga Midstream and Niobrara G&P, which commenced operations in September 2013.
- an increase in operation and maintenance expense as a result of the continued development of the Polar and Divide system.
- an environmental remediation accrual for assets contributed to Polar and Divide in connection with the 2016 Drop Down.

<u>Cost of Natural Gas and NGLs</u>. 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.

<u>Operation and Maintenance</u>. Operation and maintenance expense increased during the year ended December 31, 2015 primarily reflecting an environmental remediation accrual for assets contributed to Polar and Divide, an increase in connection fee pass-through expense for Polar and Divide as a result of increased volumes (revenue component is recognized in other revenues), an increase in property taxes and an increase in compensation expense. These increases were partially offset by 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.)

Operation and maintenance expense increased during the year ended December 31, 2014 primarily as a result of the 2014 start up of Tioga Midstream, an environmental remediation accrual for assets contributed to Polar and Divide, 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).

<u>General and Administrative</u>. General and administrative expense increased during the year ended December 31, 2015 reflecting a an increase in salaries, benefits and unit-based and noncash compensation and an increase in rent expense. These increases were partially offset by 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").

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 and rent expenses.

<u>Transaction Costs</u>. 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. Transaction costs also include financial and legal advisory expenses incurred by Summit Investments in 2015 and 2014 for third-party acquisitions that were allocated to us in connection with the 2016 Drop Down.

<u>Depreciation and Amortization</u>. 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.

<u>Interest Expense</u>. 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 and an increase in interest expense allocated to us in connection with the 2016 Drop Down.

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 and an increase in interest expense allocated to us in connection with the 2016 Drop Down.

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

***Utica Shale.*** Our ownership interests in Ohio Gathering are the primary component of the Utica Shale reportable segment. We acquired substantially all of Summit Investments' indirect ownership interest in Ohio Gathering, a natural gas gathering system and a condensate stabilization facility, in March 2016 (see the notes to the consolidated financial statements for additional information). The Utica Shale reportable segment also includes Summit Utica, a natural gas gathering system, which was acquired from a subsidiary of Summit Investments in March 2016. Our segment financial results include recognition of our proportional adjusted EBITDA activity for Ohio Gathering since January 2014, the date on which common control began.

Volume throughput for our Utica Shale reportable segment, exclusive of volume throughput data for Ohio Gathering which we do not operate, follows.

| | Utica Shale (1) | | |
|---|---|---|---|
| | Year ended December 31, | | Percentage Change |
| | 2015 | 2014 | 2015 v. 2014 |
| **Operating Data:** | | | |
| Average throughput (MMcf/d) (2) | 37 | 1 | * |

(1) Summit Utica contract terms related to throughput rate per Mcf are excluded for confidentiality purposes.
(2) For the year ended December 31, 2014. For the period of SMLP's ownership in 2014, average throughput was 12 MMcf/d.
* Not considered meaningful

Financial data for our Utica Shale reportable segment follows.

| | Utica Shale | | |
|---|---|---|---|
| | Year ended December 31, | | Percentage Change |
| | 2015 | 2014 | 2015 v. 2014 |
| | (In thousands) | | |
| **Revenues:** | | | |
| Gathering services and related fees | $ 4,700 | $ 190 | * |
| Total revenues | 4,700 | 190 | * |
| **Costs and expenses:** | | | |
| Operation and maintenance | 1,017 | — | * |
| General and administrative | 1,477 | 20 | * |
| Depreciation and amortization | 1,417 | — | * |
| Total costs and expenses | 3,911 | 20 | * |
| **Add:** | | | |
| Proportional adjusted EBITDA for equity method investees | 33,667 | 6,006 | |
| Depreciation and amortization | 1,417 | — | |
| Segment adjusted EBITDA | $ 35,873 | $ 6,176 | * |

* Not considered meaningful

Year ended December 31, 2015. Segment adjusted EBITDA increased $29.7 million during 2015 reflecting:

- an increase in Ohio Gathering's adjusted EBITDA due to ongoing growth and development.
- a full year of operations and the growth and development of Summit Utica.

Depreciation and amortization increased over 2015 as a result of assets into service at Summit Utica.

***Williston Basin.*** Bison Midstream, Polar and Divide and Tioga Midstream 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. Tioga Midstream, an associated natural gas, crude oil and produced water gathering system, was acquired from a subsidiary of Summit Investments in March 2016. Our results include activity for all periods during which the assets were under common control. Common control began in February 2013 for Bison Midstream and Polar and Divide and in April 2014 for Tioga Midstream.

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) | 23 | 18 | 14 | 28 % | 29 % |
| Average throughput rate per Mcf – gas | $ 2.40 | $ 3.44 | $ 3.86 | (30)% | (11)% |
| Average throughput – liquids (Mbbl/d) (2) | 67.7 | 40.7 | 10.9 | 66 % | * |
| Average throughput rate per Bbl – liquids | $ 1.84 | $ 1.69 | $ 0.95 | 9 % | 78 % |

* 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 increased in 2015 due to growth on the Tioga Midstream system and increases in gas-to-oil ratios on existing production. This effect was partially offset by the effects of customers reducing their drilling activities in response to continued declines in commodity prices.

The increase in natural gas volume throughput in 2014 primarily reflects additional pad site connections and newly installed compression capacity on Bison Midstream, 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.

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 | $ 62,899 | $ 41,766 | $ 21,132 | 51 % | 98 % |
| Natural gas, NGLs and condensate sales | 23,525 | 56,040 | 47,130 | (58)% | 19 % |
| Other revenues | 12,505 | 12,001 | 13,239 | 4 % | (9)% |
| Total revenues | 98,929 | 109,807 | 81,501 | (10)% | 35 % |
| **Costs and expenses:** | | | | | |
| Cost of natural gas and NGLs | 23,090 | 54,481 | 54,840 | (58)% | (1)% |
| Operation and maintenance | 26,586 | 22,926 | 8,849 | 16 % | 159 % |
| General and administrative | 5,400 | 8,474 | 4,402 | (36)% | 93 % |
| Depreciation and amortization | 31,376 | 24,027 | 16,669 | 31 % | 44 % |
| Environmental remediation | 21,800 | 5,000 | — | * | * |
| (Gain) loss on asset sales, net | 5 | 296 | — | * | * |
| Long-lived asset impairment | 7,554 | — | — | * | * |
| Goodwill impairment | 203,373 | 54,199 | — | * | * |
| Total costs and expenses | 319,184 | 169,403 | 84,760 | 88 % | 100 % |
| **Add:** | | | | | |
| Depreciation and amortization | 31,376 | 24,027 | 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 | $ 34,008 | $ 30,009 | $ 17,350 | 13 % | 73 % |

* Not considered meaningful

<u>Year ended December 31, 2015</u>. Segment adjusted EBITDA increased $4.0 million during 2015 reflecting:

- an environmental remediation accrual for assets contributed to Polar and Divide in connection with the 2016 Drop Down.
- 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.
- 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.
- the impact of declining commodity prices which negatively affect the margins we earn under percent-of-proceeds arrangements at Bison Midstream.
- an increase in operation and maintenance expense largely as a result of system buildout on the Polar and Divide and Tioga Midstream systems.

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 $12.7 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.
- 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.
- an environmental remediation accrual for assets contributed to Polar and Divide in connection with the 2016 Drop Down

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.

***Piceance/DJ Basins.*** Grand River, a natural gas gathering and processing system, provides our midstream services for the Piceance/DJ Basins 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 2012, the date on which common control began. Niobrara G&P, an associated natural gas gathering and processing system in the DJ Basin, was acquired from a subsidiary of Summit Investments in March 2016. Our results include activity for Niobrara G&P since February 2013, the date on which common control began. For additional information, see the notes to the consolidated financial statements.

Operating data for our Piceance/DJ Basins reportable segment follows.

| | Piceance/DJ Basins | | | | |
|---|---|---|---|---|---|
| | Year ended December 31, | | | Percentage Change | |
| | 2015 | 2014 | 2013 | 2015 v. 2014 | 2014 v. 2013 |
| **Operating Data:** | | | | | |
| Average throughput (MMcf/d) | 609 | 663 | 647 | (8)% | 2% |
| Average throughput rate per Mcf | $ 0.57 | $ 0.51 | $ 0.41 | 12 % | 24% |

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/DJ Basins reportable segment follows.

| | Piceance/DJ Basins | | | | |
|---|---|---|---|---|---|
| | 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 | $ 161,291 | $ 122,852 | $ 96,485 | 31 % | 27 % |
| Natural gas, NGLs and condensate sales | 11,854 | 27,606 | 23,865 | (57)% | 16 % |
| Other revenues | 7,273 | 11,019 | 9,397 | (34)% | 17 % |
| Total revenues | 180,418 | 161,477 | 129,747 | 12 % | 24 % |
| **Costs and expenses:** | | | | | |
| Cost of natural gas and NGLs | 8,308 | 17,934 | 13,197 | (54)% | 36 % |
| Operation and maintenance | 36,674 | 37,945 | 35,025 | (3)% | 8 % |
| General and administrative | 3,624 | 10,029 | 14,233 | (64)% | (30)% |
| Depreciation and amortization | 47,433 | 42,959 | 36,185 | 10 % | 19 % |
| (Gain) loss on asset sales | (190) | 146 | — | * | * |
| Long-lived asset impairment | 1,220 | — | — | * | * |
| Goodwill impairment | 45,478 | — | — | * | * |
| Total costs and expenses | 142,547 | 109,013 | 98,640 | 31 % | 11 % |
| Other income | — | 1,185 | — | * | * |
| **Add:** | | | | | |
| Depreciation and amortization | 47,433 | 42,959 | 36,185 | | |
| 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 adjustment | — | 1,185 | — | | |
| Segment adjusted EBITDA | $ 110,222 | $ 110,763 | $ 79,687 | — % | 39 % |

* Not considered meaningful

Year ended December 31, 2015. Segment adjusted EBITDA decreased $0.5 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 Grand River anchor customer, partially offset by the contribution from Niobrara G&P.
- 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 8 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, the March 2014 commissioning of a cryogenic processing plant and the development of Niobrara G&P. 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 $31.1 million during 2014 reflecting:

- higher gathering services and related fees, largely due to the proportionate contribution of higher margin volume throughput from certain customers, the contribution from Niobrara G&P 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 16 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.

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)% |

*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.

***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

<u>Year ended December 31, 2015</u>. 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.
- the previously mentioned decision to discontinue allocating certain corporate general and administrative expenses to our reportable segments.
- an increase in operation and maintenance primarily as a result of system expansion and the associated increase in volume throughput.

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.

***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 | $ 32,942 | $ 17,957 | $ 11,144 | 83 % | 61% |
| Transaction costs | 1,342 | 2,985 | 2,841 | (55)% | 5% |
| Interest expense | 59,092 | 48,586 | 21,314 | 22 % | 128% |

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. Transaction costs also include financial and legal advisory expenses incurred by Summit Investments in 2015 and 2014 for third-party acquisitions that were allocated to us in connection with the 2016 Drop Down.

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 and an increase in interest expense allocated to us in connection with the 2016 Drop Down.

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 and an increase in interest expense allocated to us in connection with the 2016 Drop Down.

## Non-GAAP Financial Measures

EBITDA, adjusted EBITDA and distributable cash flow are not financial measures presented in accordance with GAAP.

- ***EBITDA.*** 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.
- ***Adjusted EBITDA.*** We define adjusted EBITDA as EBITDA plus our proportional adjusted EBITDA for equity method investees, adjustments related to MVC shortfall payments, impairments and other noncash expenses or losses, less income (loss) from equity method investees and other noncash income or gains.
- ***Distributable Cash Flow.*** 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.

***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.
- Proportional adjusted EBITDA for equity method investees accounts for our pro rata share of Ohio Gathering's adjusted EBITDA.
- 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 adjustment 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/DJ Basins" and Note 16 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 9 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 16 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.

***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 | $ (222,228) | $ (47,368) | $ 47,008 |
| **Add:** | | | |
| Interest expense | 59,092 | 48,586 | 21,314 |
| Income tax expense | — | 854 | 729 |
| Depreciation and amortization | 105,903 | 91,822 | 72,264 |
| **Less:** | | | |
| Interest income | 2 | 4 | 5 |
| Income tax benefit | 603 | — | — |
| EBITDA | $ (57,838) | $ 93,890 | $ 141,310 |
| **Add:** | | | |
| Proportional adjusted EBITDA for equity method investees | 33,667 | 6,006 | — |
| Adjustments related to MVC shortfall payments | (11,902) | 26,565 | 17,025 |
| Unit-based and noncash compensation | 7,017 | 5,841 | 4,242 |
| Loss on asset sales | 42 | 442 | 113 |
| Long-lived asset impairment | 9,305 | 5,505 | — |
| Goodwill impairment | 248,851 | 54,199 | — |
| **Less:** | | | |
| (Loss) from equity method investees | (6,563) | (16,712) | — |
| Gain on asset sales | 214 | — | — |
| Impact of purchase price adjustment | — | 1,185 | — |
| Adjusted EBITDA | $ 235,491 | $ 207,975 | $ 162,690 |
| Add cash interest received | 2 | 4 | 5 |
| **Less:** | | | |
| Cash interest paid | 59,302 | 38,453 | 13,170 |
| Senior notes interest adjustment | (1,421) | 6,733 | 12,125 |
| Cash taxes paid | — | — | 660 |
| Maintenance capital expenditures | 12,681 | 18,082 | 16,129 |
| Distributable cash flow | $ 164,931 | $ 144,711 | $ 120,611 |

***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 | $ 191,375 | $ 152,953 | $ 135,411 |
| **Add:** | | | |
| (Loss) from equity method investees | (6,563) | (16,712) | — |
| Interest expense, excluding deferred loan costs | 54,783 | 44,750 | 18,557 |
| Income tax expense | — | 854 | 729 |
| Impact of purchase price adjustment | — | 1,185 | — |
| Changes in operating assets and liabilities | 3,541 | (18,603) | (9,027) |
| Gain on asset sales | 214 | — | — |
| **Less:** | | | |
| Unit-based compensation | 7,017 | 5,841 | 4,242 |
| Distributions from equity method investees | 34,641 | 2,992 | — |
| Interest income | 2 | 4 | 5 |
| Income tax benefit | 603 | — | — |
| Loss on asset sales | 42 | 442 | 113 |
| Long-lived asset impairment | 9,305 | 5,505 | — |
| Goodwill impairment | 248,851 | 54,199 | — |
| Write-off of debt issuance costs | 727 | 1,554 | — |
| EBITDA | $ (57,838) | $ 93,890 | $ 141,310 |
| **Add:** | | | |
| Proportional adjusted EBITDA for equity method investees | 33,667 | 6,006 | — |
| Adjustments related to MVC shortfall payments | (11,902) | 26,565 | 17,025 |
| Unit-based compensation | 7,017 | 5,841 | 4,242 |
| Loss on asset sales | 42 | 442 | 113 |
| Long-lived asset impairment | 9,305 | 5,505 | — |
| Goodwill impairment | 248,851 | 54,199 | — |
| **Less:** | | | |
| (Loss) from equity method investees | (6,563) | (16,712) | — |
| Gain on asset sales | 214 | — | — |
| Impact of purchase price adjustment | — | 1,185 | — |
| Adjusted EBITDA | $ 235,491 | $ 207,975 | $ 162,690 |
| Add cash interest received | 2 | 4 | 5 |
| **Less:** | | | |
| Cash interest paid | 59,302 | 38,453 | 13,170 |
| Senior notes interest adjustment | (1,421) | 6,733 | 12,125 |
| Cash taxes paid | — | — | 660 |
| Maintenance capital expenditures | 12,681 | 18,082 | 16,129 |
| Distributable cash flow | $ 164,931 | $ 144,711 | $ 120,611 |

# 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.

## 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, 9, 11 and 16 to the consolidated financial statements.

## Debt

***Revolving Credit Facility.*** As of December 31, 2015, we had 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.

On February 25, 2016, we closed on an amendment to the revolving credit facility, which became effective concurrent with the Initial Close of the 2016 Drop Down. In connection with this amendment, (i) the revolving credit facility's borrowing capacity increased from $700.0 million to $1.25 billion, (ii) a new investment basket allowing the Co-Issuers (as defined below) to buy back up to $100.0 million of our outstanding senior unsecured notes was included, (iii) the total leverage ratio was increased to 5.50 to 1.0 through December 31, 2016 and (iv) various amendments were approved to facilitate the 2016 Drop Down.

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

***SMP Holdings Credit Facility.*** SMP Holdings had a senior secured revolving credit facility (the "SMP Revolving Credit Facility") and a senior secured term loan (the "Term Loan" and, collectively with the SMP Revolving Credit Facility, the "SMP Holdings Credit Facility") which were used to support the development of the 2016 Drop Down Assets. Borrowings under the SMP Holdings Credit Facility incurred interest at LIBOR or a base rate (as defined in the SMP Holdings Credit Facility) plus an applicable margin. Because the funding was used to support the development of the 2016 Drop Down Assets, Summit Investments allocated the SMP Holdings Credit Facility to us during the years ended December 31, 2015, 2014 and 2013.

On March 3, 2016, the outstanding balances on the SMP Holdings Credit Facility were repaid in full and the SMP Holdings Credit Facility was terminated concurrent with the closing of the 2016 Drop Down (see Note 16).

For additional information on our long-term debt and debt allocated to us, see Note 9 to the consolidated financial statements.

## Deferred Purchase Price Obligation

In March 2016, we entered into an agreement with a subsidiary of Summit Investments to fund a portion of the 2016 Drop Down whereby we have recognized a liability for a deferred purchase price obligation. For additional information on the deferred purchase price obligation, see Note 16 to the unaudited condensed 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 | $ 191,375 | $ 152,953 | $ 135,411 |
| Net cash used in investing activities | (646,720) | (1,384,803) | (659,041) |
| Net cash provided by financing activities | 449,327 | 1,233,877 | 538,080 |
| Net change in cash and cash equivalents | $ (6,018) | $ 2,027 | $ 14,450 |

***Operating activities.*** Cash flows from operating activities increased by $38.4 million for the year ended December 31, 2015 primarily due to distributions from Ohio Gathering and 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 $17.5 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 Summit Utica, Tioga Midstream, Niobrara G&P and Polar and Divide systems, 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 Summit Investments' investment in Ohio Gathering, the Partnership's acquisition of Red Rock Gathering from a subsidiary of Summit Investments and build out of the Summit Utica, Tioga Midstream, Niobrara G&P and Polar and Divide systems. 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 and Niobrara G&P systems. 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;
- Cash advances to support the buildout of the systems acquired in the 2016 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.

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

- Cash advances to fund the acquisition of Ohio Gathering and to support the buildout of the systems acquired in the 2016 Drop Down;
- 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 $297.2 million on our revolving credit facility, $294.2 million 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 as well as the systems acquired in the 2016 Drop Down.

## 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) | 33,672 | 32,384 | 1,188 | 100 | — |
| Total contractual obligations | $ 1,262,761 | $ 83,243 | $ 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 9 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 15 to the consolidated financial statements for additional information.

***Subsequent events.*** In March 2016, we borrowed an additional $360.0 million under our revolving credit facility and recognized a liability of $507.4 million for the deferred purchase price obligation, both in connection with the 2016 Drop Down (see Notes 9 and 16 to the consolidated financial statements for additional information). Additional interest expense on the incremental revolving credit facility borrowings will total $8.7 million on an annualized basis with maturity in November 2018, assuming no change in the balance, rate or commitment fee from December 31, 2015. The deferred purchase price obligation is due no later than December 31, 2020 and is currently expected to be $860.3 million based on information available as of March 31, 2016. There are no cash interest payments associated with the deferred purchase price obligation.

### 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:** | | | |
| Utica Shale | $ 94,994 | $ 24,787 | $ — |
| Williston Basin | 147,477 | 227,283 | 129,236 |
| Piceance/DJ Basins | 21,144 | 42,417 | 88,104 |
| Barnett Shale | 6,875 | 14,567 | 29,534 |
| Marcellus Shale | 1,306 | 33,866 | 1,822 |
| Total reportable segment capital expenditures | 271,796 | 342,920 | 248,696 |
| Corporate | 429 | 460 | 930 |
| Total capital expenditures | $ 272,225 | $ 343,380 | $ 249,626 |

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 $272.2 million, which included $12.7 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 revolving credit facility, 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 11 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.

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

(1) See Notes 3 and 8 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, 8 and 10 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 $1.8 billion and net amortizing intangible assets with a carrying value of approximately $461.3 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.

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 are 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/DJ Basins customer for which we determined that it 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/DJ Basins, 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 |
| Piceance/DJ Basins | 15,508 | 37,131 | (21,623) | 15,508 |
| Barnett Shale | 677 | 2,377 | (1,700) | 677 |
| Total change in deferred revenue | $ 28,082 | $ 39,535 | $ (11,453) | $ 28,082 |
| **MVC shortfall payment adjustments:** | | | | |
| Piceance/DJ Basins | $ 25,704 | $ 25,704 | $ 33 | $ 25,737 |
| Barnett Shale | 1,142 | 1,142 | (482) | 660 |
| Marcellus Shale | 3,237 | 3,237 | — | 3,237 |
| 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.

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 8 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 be,” “will continue,” “will likely result,” and similar expressions, or future conditional verbs such as “may,” “will,” “should,” “would,” and “could.” In addition, any statement concerning future financial performance (including future revenues, earnings or growth rates), ongoing business strategies or prospects, and possible actions taken by us, 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;
- 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 8. Financial Statements and Supplementary Data.

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the Board of Directors of Summit Midstream GP, LLC and 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 membership interests, 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 the 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.

The consolidated financial statements give retrospective effect to the Partnership's acquisition of Summit Midstream Utica, LLC, Meadowlark Midstream Company, LLC, Tioga Midstream, LLC, and SMP Holdings' 40.0% ownership interest in each of Ohio Gathering Company, L.L.C. and Ohio Condensate Company, L.L.C. from Summit Midstream Partners Holdings, LLC, (collectively the "2016 Drop Down") as a combination of entities under common control, which has been accounted for in a manner similar to a pooling of interests, as described in Notes 1 and 16 to the consolidated financial statements.

/s/ DELOITTE & TOUCHE LLP
Atlanta, Georgia

February 26, 2016 (June 6, 2016 as to the effects of the 2016 Drop Down as described in Notes 1 and 16, and the retrospective application of the change in accounting policy for presentation of debt issuance costs in Note 1)

## SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
## CONSOLIDATED BALANCE SHEETS

| | December 31, 2015 | December 31, 2014 |
|---|---|---|
| | (In thousands) | |
| **Assets** | | |
| **Current assets:** | | |
| Cash and cash equivalents | $ 21,793 | $ 27,811 |
| Accounts receivable | 89,581 | 92,908 |
| Insurance receivable | — | 25,000 |
| Other current assets | 3,573 | 3,600 |
| Total current assets | 114,947 | 149,319 |
| Property, plant and equipment, net | 1,812,783 | 1,622,640 |
| Intangible assets, net | 461,310 | 489,282 |
| Goodwill | 16,211 | 265,062 |
| Investment in equity method investees | 751,168 | 706,172 |
| Other noncurrent assets | 8,253 | 9,987 |
| Total assets | $ 3,164,672 | $ 3,242,462 |
| | | |
| **Liabilities and Partners' Capital** | | |
| **Current liabilities:** | | |
| Trade accounts payable | $ 40,808 | $ 38,391 |
| Due to affiliate | 1,149 | 2,711 |
| Deferred revenue | 677 | 2,377 |
| Ad valorem taxes payable | 10,271 | 9,179 |
| Accrued interest | 17,483 | 18,858 |
| Accrued environmental remediation | 7,900 | 25,000 |
| Other current liabilities | 13,297 | 15,307 |
| Total current liabilities | 91,585 | 111,823 |
| Long-term debt | 1,267,270 | 1,232,207 |
| Deferred revenue | 45,486 | 55,239 |
| Noncurrent accrued environmental remediation | 5,764 | 5,000 |
| Other noncurrent liabilities | 7,268 | 7,515 |
| Total liabilities | 1,417,373 | 1,411,784 |
| Commitments and contingencies (Note 15) | | |
| | | |
| 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 | 763,057 | 863,789 |
| Total partners' capital | 1,747,299 | 1,830,678 |
| Total liabilities and partners' capital | $ 3,164,672 | $ 3,242,462 |

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

## SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
## CONSOLIDATED STATEMENTS OF OPERATIONS

| | Year ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| | (In thousands, except per-unit amounts) | | |
| **Revenues:** | | | |
| Gathering services and related fees | $ 337,819 | $ 267,478 | $ 216,352 |
| Natural gas, NGLs and condensate sales | 42,079 | 97,094 | 88,185 |
| Other revenues | 20,659 | 22,597 | 21,623 |
| Total revenues | 400,557 | 387,169 | 326,160 |
| **Costs and expenses:** | | | |
| Cost of natural gas and NGLs | 31,398 | 72,415 | 68,037 |
| Operation and maintenance | 94,986 | 94,869 | 78,175 |
| General and administrative | 45,108 | 43,281 | 36,716 |
| Transaction costs | 1,342 | 2,985 | 2,841 |
| Depreciation and amortization | 105,117 | 90,878 | 71,232 |
| Environmental remediation | 21,800 | 5,000 | — |
| (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 | 557,735 | 369,574 | 257,114 |
| Other income | 2 | 1,189 | 5 |
| Interest expense | (59,092) | (48,586) | (21,314) |
| (Loss) income before income taxes | (216,268) | (29,802) | 47,737 |
| Income tax benefit (expense) | 603 | (854) | (729) |
| Loss from equity method investees | (6,563) | (16,712) | — |
| Net (loss) income | $ (222,228) | $ (47,368) | $ 47,008 |
| Less net income attributable to Summit Investments | (30,016) | (23,376) | 3,424 |
| Net (loss) income attributable to SMLP | (192,212) | (23,992) | 43,584 |
| Less net (loss) income attributable to general partner, including IDRs | 3,398 | 3,125 | 1,035 |
| Net (loss) income attributable to limited partners | $ (195,610) | $ (27,117) | $ 42,549 |
| | | | |
| **(Loss) earnings per limited partner unit:** | | | |
| Common unit – basic | $ (3.20) | $ (0.49) | $ 0.86 |
| Common unit – diluted | $ (3.20) | $ (0.49) | $ 0.86 |
| Subordinated unit – basic and diluted | $ (2.88) | $ (0.44) | $ 0.79 |
| | | | |
| **Weighted-average limited partner units outstanding:** | | | |
| Common units – basic | 39,217 | 33,311 | 26,951 |
| Common units – diluted | 39,217 | 33,311 | 27,101 |
| Subordinated units – basic and diluted | 24,410 | 24,410 | 24,410 |

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

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

| | Partners' capital | | | Summit Investments' equity in contributed subsidiaries | Total |
|---|---|---|---|---|---|
| | Limited partners | | | | |
| | Common | Subordinated | General partner | | |
| | | | (In thousands) | | |
| **Partners' capital, January 1, 2013** | $ 418,856 | $ 380,169 | $ 20,222 | $ 209,108 | $ 1,028,355 |
| Net income | 22,311 | 20,238 | 1,035 | 3,424 | 47,008 |
| Distributions to unitholders | (46,286) | (42,107) | (1,803) | — | (90,196) |
| Unit-based compensation | 2,999 | — | — | — | 2,999 |
| Consolidation of Bison Midstream net assets | — | — | — | 303,168 | 303,168 |
| Contribution from Summit Investments to Bison Midstream | — | — | — | 2,229 | 2,229 |
| Purchase of Bison Midstream | 47,936 | — | 978 | (248,914) | (200,000) |
| Contribution of net assets from Summit Investments in excess of consideration paid for Bison Midstream | 28,558 | 26,846 | 1,131 | (56,535) | — |
| Issuance of units in connection with the Mountaineer Acquisition | 98,000 | — | 2,000 | — | 100,000 |
| Consolidation of Polar Midstream net assets | — | — | — | 216,105 | 216,105 |
| Consolidation of 2016 Drop Down net assets | — | — | — | 21,968 | 21,968 |
| Class B membership interest noncash compensation | 17 | — | — | 1,226 | 1,243 |
| Repurchase of DFW Net Profits Interests | (5,859) | (5,859) | (239) | — | (11,957) |
| Cash advance to Summit Investments from contributed subsidiaries, net | — | — | — | (50,087) | (50,087) |
| Capitalized interest allocated to contributed subsidiaries from Summit Investments | — | — | — | 2,539 | 2,539 |
| Expenses paid by Summit Investments on behalf of contributed subsidiaries | — | — | — | 22,380 | 22,380 |
| Capital expenditures paid by Summit Investments on behalf of contributed subsidiaries | — | — | — | 52 | 52 |
| **Partners' capital, December 31, 2013** | $ 566,532 | $ 379,287 | $ 23,324 | $ 426,663 | $ 1,395,806 |

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

| | Partners' capital | | | Summit Investments' equity in contributed subsidiaries | Total |
|---|---|---|---|---|---|
| | Limited partners | | | | |
| | Common | Subordinated | General partner | | |
| | | | (In thousands) | | |
| **Partners' capital, December 31, 2013** | $ 566,532 | $ 379,287 | $ 23,324 | $ 426,663 | $ 1,395,806 |
| Net (loss) income | (15,948) | (11,169) | 3,125 | (23,376) | (47,368) |
| Distributions to unitholders | (67,658) | (49,796) | (4,770) | — | (122,224) |
| Unit-based compensation | 4,696 | — | — | — | 4,696 |
| Tax withholdings on vested SMLP LTIP awards | (656) | — | — | — | (656) |
| Issuance of common units, net of offering costs | 197,806 | — | — | — | 197,806 |
| Contribution from general partner | — | — | 4,235 | — | 4,235 |
| Purchase of Red Rock Gathering | — | — | — | (307,941) | (307,941) |
| Excess of purchase price over acquired carrying value of Red Rock Gathering | (37,910) | (26,891) | (1,323) | 66,124 | — |
| Assets contributed to Red Rock Gathering from Summit Investments | 2,426 | 1,722 | 85 | — | 4,233 |
| Cash advance from Summit Investments to contributed subsidiaries, net | — | — | — | 674,383 | 674,383 |
| Expenses paid by Summit Investments on behalf of contributed subsidiaries | — | — | — | 24,884 | 24,884 |
| Capitalized interest allocated to contributed subsidiaries from Summit Investments | — | — | — | 1,310 | 1,310 |
| Capital expenditures paid by Summit Investments on behalf of contributed subsidiaries | — | — | — | 597 | 597 |
| Class B membership interest noncash compensation | — | — | — | 1,145 | 1,145 |
| Repurchase of SMLP LTIP units | (228) | — | — | — | (228) |
| **Partners' capital, December 31, 2014** | $ 649,060 | $ 293,153 | $ 24,676 | $ 863,789 | $ 1,830,678 |

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

| | Partners' capital | | | Summit Investments' equity in contributed subsidiaries | Total |
|---|---|---|---|---|---|
| | Limited partners | | | | |
| | Common | Subordinated | General partner | | |
| | | | (In thousands) | | |
| **Partners' capital, December 31, 2014** | $ 649,060 | $ 293,153 | $ 24,676 | $ 863,789 | $ 1,830,678 |
| Net (loss) income | (123,817) | (71,793) | 3,398 | (30,016) | (222,228) |
| Distributions to unitholders | (86,880) | (55,410) | (9,784) | — | (152,074) |
| Unit-based compensation | 6,174 | — | — | — | 6,174 |
| Tax withholdings on vested SMLP LTIP awards | (1,616) | — | — | — | (1,616) |
| Issuance of common units, net of offering costs | 221,977 | — | — | — | 221,977 |
| Contribution from general partner | — | — | 4,737 | — | 4,737 |
| Purchase of Polar and Divide | — | — | — | (285,677) | (285,677) |
| Excess of acquired carrying value over consideration paid for Polar and Divide | 80,079 | 47,681 | 2,607 | (130,367) | — |
| Cash advance from Summit Investments to contributed subsidiaries, net | — | — | — | 320,527 | 320,527 |
| Expenses paid by Summit Investments on behalf of contributed subsidiaries | — | — | — | 22,879 | 22,879 |
| Capitalized interest allocated from Summit Investments to contributed subsidiaries | — | — | — | 1,079 | 1,079 |
| Class B membership interest noncash compensation | — | — | — | 843 | 843 |
| **Partners' capital, December 31, 2015** | $ 744,977 | $ 213,631 | $ 25,634 | $ 763,057 | $ 1,747,299 |

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

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

| | Year ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| | | (In thousands) | |
| **Cash flows from operating activities:** | | | |
| Net (loss) income | $ (222,228) | $ (47,368) | $ 47,008 |
| **Adjustments to reconcile net (loss) income to net cash provided by operating activities:** | | | |
| Depreciation and amortization | 105,903 | 91,822 | 72,264 |
| Amortization of deferred loan costs | 4,309 | 3,836 | 2,757 |
| Unit-based and noncash compensation | 7,017 | 5,841 | 4,242 |
| Loss from equity method investees | 6,563 | 16,712 | — |
| Distributions from equity method investees | 34,641 | 2,992 | — |
| (Gain) loss on asset sales, net | (172) | 442 | 113 |
| Long-lived asset impairment | 9,305 | 5,505 | — |
| Goodwill impairment | 248,851 | 54,199 | — |
| Write-off of debt issuance costs | 727 | 1,554 | — |
| Purchase accounting adjustment | — | (1,185) | — |
| **Changes in operating assets and liabilities:** | | | |
| Accounts receivable | 3,328 | (21,503) | (21,950) |
| Insurance receivable | 25,000 | (25,000) | — |
| Trade accounts payable | (1,450) | (420) | (6,153) |
| Due to affiliate | 1,377 | (883) | 1,427 |
| Change in deferred revenue | (11,453) | 26,378 | 16,685 |
| Ad valorem taxes payable | 1,092 | 804 | (11) |
| Accrued interest | (1,375) | 6,714 | 12,128 |
| Accrued environmental remediation, net | (16,336) | 30,000 | — |
| Other, net | (3,724) | 2,513 | 6,901 |
| Net cash provided by operating activities | 191,375 | 152,953 | 135,411 |
| **Cash flows from investing activities:** | | | |
| Capital expenditures | (272,225) | (343,380) | (249,626) |
| Initial contribution to Ohio Gathering | — | (8,360) | — |
| Acquisition of Ohio Gathering Option | — | (190,000) | — |
| Option Exercise | — | (382,385) | — |
| Contributions to equity method investees | (86,200) | (145,131) | — |
| Proceeds from asset sales | 323 | 325 | 585 |
| Acquisition of gathering systems | — | (10,872) | (210,000) |
| Acquisitions of gathering systems from affiliate | (288,618) | (305,000) | (200,000) |
| Net cash used in investing activities | (646,720) | (1,384,803) | (659,041) |

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

| | Year ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| | | (In thousands) | |
| **Cash flows from financing activities:** | | | |
| Distributions to unitholders | (152,074) | (122,224) | (90,196) |
| Borrowings under revolving credit facility | 367,000 | 294,295 | 476,950 |
| Repayments under revolving credit facility | (151,000) | (430,295) | (297,180) |
| Borrowings under term loan | — | 400,000 | 200,000 |
| Repayments under term loan | (182,500) | (100,000) | (100,000) |
| Deferred loan costs | (412) | (8,323) | (14,059) |
| Proceeds from issuance of common units, net | 221,977 | 197,806 | — |
| Contribution from general partner | 4,737 | 4,235 | 2,229 |
| Cash advance from (to) Summit Investments to (from) contributed subsidiaries, net | 320,527 | 674,383 | (50,087) |
| Expenses paid by Summit Investments on behalf of contributed subsidiaries | 22,879 | 24,884 | 22,380 |
| Issuance of senior notes | — | 300,000 | 300,000 |
| Repurchase of equity-based compensation awards | — | (228) | (11,957) |
| Issuance of units to affiliate in connection with the Mountaineer Acquisition | — | — | 100,000 |
| Other, net | (1,807) | (656) | — |
| Net cash provided by financing activities | 449,327 | 1,233,877 | 538,080 |
| Net change in cash and cash equivalents | (6,018) | 2,027 | 14,450 |
| Cash and cash equivalents, beginning of period | 27,811 | 25,784 | 11,334 |
| Cash and cash equivalents, end of period | $ 21,793 | $ 27,811 | $ 25,784 |
| | | | |
| **Supplemental cash flow disclosures:** | | | |
| Cash interest paid | $ 59,302 | $ 38,453 | $ 13,170 |
| Less capitalized interest | 3,372 | 4,646 | 6,690 |
| Interest paid (net of capitalized interest) | $ 55,930 | $ 33,807 | $ 6,480 |
| | | | |
| Cash paid for taxes | $ — | $ — | $ 660 |
| | | | |
| **Noncash investing and financing activities:** | | | |
| Capital expenditures in trade accounts payable (period-end accruals) | $ 34,977 | $ 31,110 | $ 30,528 |
| Excess of acquired carrying value over consideration paid for Polar and Divide | 130,367 | — | — |
| Capitalized interest allocated to contributed subsidiaries from Summit Investments | 1,079 | 1,310 | 2,539 |
| Capital expenditures paid by Summit Investments on behalf of contributed subsidiaries | — | 597 | 52 |
| Excess of consideration paid over acquired carrying value of Red Rock Gathering | — | (66,124) | — |
| Assets contributed to Red Rock Gathering from Summit Investments | — | 4,233 | — |
| Issuance of units to affiliate to partially fund the Bison Drop Down | — | — | 48,914 |
| Contribution of net assets from Summit Investments in excess of consideration paid for Bison Midstream | — | — | 56,535 |

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

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

### 1. ORGANIZATION, BUSINESS OPERATIONS AND PRESENTATION AND CONSOLIDATION

***Organization.*** Summit Midstream Partners, LP ("SMLP" or the "Partnership"), a Delaware limited partnership, was formed in May 2012 and began operations in October 2012 in connection with its initial public offering ("IPO") of common limited partner units. SMLP is a growth-oriented limited partnership focused on developing, owning and operating midstream energy infrastructure assets that are strategically located in the core producing areas of unconventional resource basins, primarily shale formations, in the continental United States. Our business activities are conducted through our subsidiary, Summit Midstream Holdings, LLC ("Summit Holdings"), a Delaware limited liability company, and its subsidiaries. References to the "Partnership," "we," or "our," refer collectively to SMLP and its subsidiaries.

Summit Midstream GP, LLC, a Delaware limited liability company (the "general partner"), manages our operations and activities. Summit Midstream Partners, LLC, a Delaware limited liability company ("Summit Investments"), is the ultimate owner of our general partner and has the right to appoint the entire board of directors of our general partner. Summit Investments is controlled by Energy Capital Partners II, LLC and its parallel and co-investment funds (collectively, "Energy Capital Partners").

In addition to its 2% general partner interest in SMLP (including the incentive distribution rights ("IDRs") in respect of SMLP), Summit Investments has direct and indirect ownership interests in our common and subordinated units. As of December 31, 2015, Summit Investments beneficially owned 5,444,731 SMLP common units and all of our subordinated units.

Our operations are conducted through, and our operating assets are owned by, various wholly-owned operating subsidiaries. Neither SMLP nor its subsidiaries have any employees. All of the personnel that conduct our business are employed by Summit Investments, but these individuals are sometimes referred to as our employees.

Effective with the completion of its IPO, SMLP had a 100% ownership interest in Summit Holdings, which had a 100% ownership interest in both DFW Midstream Services LLC ("DFW Midstream") and Grand River Gathering, LLC ("Grand River" or the "Legacy Grand River" system).

On June 4, 2013, the Partnership acquired all of the membership interests of Bison Midstream, LLC ("Bison Midstream") from a subsidiary of Summit Investments (the "Bison Drop Down"). As such, the Bison Drop Down was determined to be a transaction among entities under common control. Prior to the Bison Drop Down, on February 15, 2013, Summit Investments acquired Bear Tracker Energy, LLC ("BTE"), which was subsequently renamed Meadowlark Midstream Company, LLC ("Meadowlark Midstream"). The net assets that comprise Bison Midstream were carved out from Meadowlark Midstream in connection with the Bison Drop Down. Common control of Bison Midstream began in February 2013.

On June 21, 2013, Mountaineer Midstream Company, LLC ("Mountaineer Midstream"), a newly formed, wholly owned subsidiary of the Partnership, acquired natural gas gathering pipeline and compression assets from an affiliate of MarkWest Energy Partners, L.P. ("MarkWest") (the "Mountaineer Acquisition"). In December 2013, Mountaineer Midstream was merged into DFW Midstream.

On March 18, 2014, SMLP acquired all of the membership interests of Red Rock Gathering Company, LLC ("Red Rock Gathering") from a subsidiary of Summit Investments (the "Red Rock Drop Down"). As such, the Red Rock Drop Down was determined to be a transaction among entities under common control. Common control of Red Rock Gathering began in October 2012. Concurrent with the closing of the Red Rock Drop Down, SMLP contributed its interest in Red Rock Gathering to Grand River.

On May 18, 2015, the Partnership acquired all of the membership interests of Polar Midstream, LLC ("Polar Midstream") and Epping Transmission Company, LLC ("Epping," and collectively with Polar Midstream, "Polar and Divide") from a subsidiary of Summit Investments (the "Polar and Divide Drop Down"). As such, the Polar and Divide Drop Down was determined to be a transaction among entities under common control. Polar Midstream's net assets were carved out of Meadowlark Midstream immediately prior to the Polar and Divide Drop Down. Concurrent with the closing of the Polar and Divide Drop Down, Epping became a wholly owned subsidiary of Polar Midstream and SMLP contributed Polar Midstream (including Epping) to Bison Midstream. Common control began in (i) February 2013 for Polar Midstream and (ii) April 2014 for Epping.

On February 25, 2016, the Partnership and Summit Midstream Partners Holdings, LLC (“SMP Holdings”), a wholly owned subsidiary of Summit Investments, entered into a contribution agreement (the "Contribution Agreement") pursuant to which SMP Holdings agreed to contribute to the Partnership substantially all of (i) the issued and outstanding membership interests of Summit Midstream Utica, LLC ("Summit Utica"), Meadowlark Midstream Company, LLC ("Meadowlark Midstream") and Tioga Midstream, LLC ("Tioga Midstream" and collectively with Summit Utica and Meadowlark Midstream, the "Contributed Entities"), each a limited liability company and indirect wholly owned subsidiary of SMP Holdings and (ii) SMP Holdings' 40.0% ownership interest in each of Ohio Gathering Company, L.L.C. and Ohio Condensate Company, L.L.C. (collectively with the Contributed Entities, the “2016 Drop Down Assets”)(the “2016 Drop Down”). The 2016 Drop Down closed on March 3, 2016 (the "Initial Close"). Upon Initial Close, the Partnership held a 99.0% ownership interest in the 2016 Drop Down Assets and Summit Investments held a 1.0% noncontrolling interest.

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

- Summit Utica, a natural gas gathering system operating in the Appalachian Basin, which includes the Utica and Point Pleasant shale formations in southeastern Ohio;
- Bison Midstream, an associated natural gas gathering system, operating in the Williston Basin, which includes the Bakken and Three Forks shale formations in northwestern North Dakota;
- Polar and Divide, crude oil and produced water gathering systems and transmission pipelines located in the Williston Basin, which includes the Bakken and Three Forks shale formations in northwestern North Dakota;
- Tioga Midstream, crude oil, produced water and associated natural gas gathering systems, operating in the Williston Basin, which includes the Bakken and Three Forks shale formations in northwestern North Dakota;
- Grand River, a natural gas gathering and processing system located in the Piceance Basin, which includes the Mesaverde formation and the Mancos and Niobrara shale formations in western Colorado and eastern Utah;
- Niobrara Gathering and Processing ("Niobrara G&P"), an associated natural gas gathering and processing system operating in the Denver-Julesburg ("DJ") Basin, which includes the Niobrara shale formation in northeastern Colorado;
- DFW Midstream, a natural gas gathering system, operating in the Fort Worth Basin, which includes the Barnett Shale formation in north-central Texas; and
- Mountaineer Midstream gathering system ("Mountaineer Midstream"), a natural gas gathering system, operating in the Appalachian Basin, which includes the Marcellus Shale formation in northern West Virginia.

Meadowlark Midstream is the legal entity which owns (i) certain crude oil and produced water gathering pipelines, which are managed and reported as part of the Polar and Divide system subsequent to the 2016 Drop Down and (ii) Niobrara G&P, which is managed and reported as part of the Grand River system subsequent to the 2016 Drop Down.

Ohio Gathering Company, L.L.C. and Ohio Condensate Company, L.L.C. (collectively, "Ohio Gathering") operate a natural gas gathering system and a condensate stabilization facility in the Appalachian Basin, which includes the Utica and Point Pleasant shale formations in southeastern Ohio.

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

The consolidated financial statements include the assets, liabilities, and results of operations of SMLP and its wholly owned subsidiaries. All intercompany transactions among the consolidated entities have been eliminated in consolidation. For the purposes of the consolidated financial statements, SMLP's results of operations reflect the results of operations of: (i) DFW Midstream and Grand River for all periods presented, (ii) Bison Midstream, Polar and Divide and Niobrara G&P since February 2013, (iii) Mountaineer Midstream since June 2013, (iv) Ohio

Gathering since January 2014, (v) Tioga Midstream since April 2014 and (vi) Summit Utica since December 2014. The financial position, results of operations and cash flows of Bison Midstream, Polar and Divide and Niobrara G&P included herein have been derived from the accounting records of Meadowlark Midstream on a carve-out basis (see Note 2). The carve-out allocations and estimates were based on methodologies that management believes are reasonable. The carve-out results reflected herein, however, may not reflect what these entities' financial position, results of operations or cash flows would have been if any had been a stand-alone company.

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

***Reclassifications.*** Certain reclassifications have been made to prior-year amounts to conform to current-year presentation. We combined the balances associated with the unfavorable gas gathering contract with other noncurrent liabilities. These balance sheet changes had no impact on (i) total liabilities or (ii) total liabilities and partners' capital.

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

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

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

In the first quarter of 2016, we adopted Accounting Standards Update ("ASU") No. 2015-03 Interest—Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs ("ASU 2015-03"). As a result, these consolidated financial statements reflect the retrospective reclassification of $9.2 million of deferred loan costs from other noncurrent assets to long-term debt at December 31, 2015 and $10.8 million at December 31, 2014 (see Note 2).

## 2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

***Accounts Receivable.*** Accounts receivable relate to gathering and other services provided to our customers and other counterparties. We evaluate the collectability of accounts receivable and the need for an allowance for doubtful accounts based on customer-specific facts and circumstances. To the extent we doubt the collectability of a specific customer or counterparty receivable, we recognize an allowance for doubtful accounts.

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

***Property, Plant, and Equipment.*** We record property, plant, and equipment at historical cost of construction or fair value of the assets at acquisition. We capitalize expenditures that extend the useful life of an asset or enhance its productivity or efficiency from its original design over the expected remaining period of use. For maintenance and repairs that do not add capacity or extend the useful life of an asset, we recognize expenditures as an expense as incurred. We capitalize project costs incurred during construction, including interest on funds borrowed to finance the construction of facilities, as construction in progress.

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

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

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

We base an asset's carrying value on estimates, assumptions and judgments for useful life and salvage value. Upon sale, retirement or other disposal, we remove the carrying value of an asset and its accumulated depreciation from our balance sheet and recognize the related gain or loss, if any.

Accrued capital expenditures are reflected in trade accounts payable.

***Asset Retirement Obligations.*** We record a liability for asset retirement obligations only if and when a future asset retirement obligation with a determinable life is identified. For identified asset retirement obligations, we then evaluate whether the expected date and related costs of retirement can be estimated. We have concluded that our gathering and processing assets have an indeterminate life because they are owned and will operate for an indeterminate period when properly maintained. Because we did not have sufficient information to reasonably estimate the amount or timing of such obligations and we have no current plan to discontinue use of any significant assets, we did not provide for any asset retirement obligations as of December 31, 2015 or 2014.

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

We amortize all other gas gathering contracts, or contract intangibles, over the period of economic benefit based upon expected revenues over the life of the contract. The useful life of these contracts ranges from 10 years to 25 years. We recognize the amortization expense associated with these contracts in depreciation and amortization expense.

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

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

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

If the reporting unit’s fair value exceeds its carrying amount, we conclude that the goodwill of the reporting unit has not been impaired and no further work is performed.

If we determine that the reporting unit’s carrying value exceeds its fair value, we proceed to step two. In step two, we compare the carrying value of the reporting unit to its implied fair value. Significant estimates and assumptions utilized in the determination of a reporting unit's implied fair value are based on a variety of factors specific to a given reporting unit's individual assets and liabilities as well as market and industry considerations. If we determine that the carrying amount of a reporting unit's goodwill exceeds its implied fair value, we recognize the excess of the carrying value over the implied fair value as an impairment loss.

***Equity Method Investments.*** We account for investments in which we exercise significant influence using the equity method so long as we (i) do not control the investee and (ii) are not the primary beneficiary. We recognize these investments in investment in equity method investees in the accompanying consolidated balance sheets. We recognize our proportionate share of earnings or loss in net income on a one-month lag.

We recognize an other-than-temporary impairment for losses in the value of equity method investees when evidence indicates that the carrying amount is no longer supportable. Evidence of a loss in value might include, but would not necessarily be limited to, absence of an ability to recover the carrying amount of the investment or inability of the equity method investee to sustain an earnings capacity that would justify the carrying amount of the investment. A current fair value of an investment that is less than its carrying amount may indicate a loss in value of the investment. We evaluate our equity method investments whenever evidence exists that would indicate a need to assess the investment for potential impairment.

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

***Impairment of Long-Lived Assets.*** We test assets for impairment when events or circumstances indicate that the carrying value of a long-lived asset may not be recoverable. The carrying value of a long-lived asset (except goodwill) is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from its use and eventual disposition. If we conclude that an asset's carrying value will not be recovered through future cash flows, we recognize an impairment loss on the long-lived asset equal to the amount by which the carrying value exceeds its fair value. We determine fair value using either a market-based approach or an income-based approach. We discuss our policy for goodwill impairment above.

***Derivative Contracts.*** We have commodity price exposure related to our sale of the physical natural gas we retain from our DFW Midstream customers and our procurement of electricity to operate DFW Midstream's electric-drive compression assets. Our gas gathering agreements with our DFW Midstream customers permit us to retain a certain quantity of natural gas that we gather to offset the power costs we incur to operate these electric-drive compression assets. We manage this direct exposure to natural gas and power prices through the use of forward power purchase contracts with wholesale power providers that require us to purchase a fixed quantity of power at a fixed heat rate based on prevailing natural gas prices based on the Waha Hub Index. Because we also sell our retainage gas at prices that are based on the Waha Hub Index, we have effectively fixed the relationship between our compression electricity expense and natural gas retainage sales.

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

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

- Level 1. Inputs represent quoted prices in active markets for identical assets or liabilities;

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

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

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

We recognize revenue earned from fee-based gathering, treating and processing services in gathering services and related fees revenue. We also earn revenue from the sale of physical natural gas purchased from our customers under percentage-of-proceeds arrangements. These revenues are recognized in natural gas, NGLs and condensate sales with corresponding expense recognition for the producer's share of the proceeds in cost of natural gas and NGLs. We sell substantially all of the natural gas that we retain from our DFW Midstream customers to offset the power expenses of the electric-driven compression on the DFW Midstream system. We also sell condensate retained from our gathering services at Grand River. Revenues from the retainage of natural gas and condensate are recognized in natural gas, NGLs and condensate sales; the associated expense is included in operation and maintenance expense. Certain customers reimburse us for costs we incur on their behalf. We record costs incurred and reimbursed by our customers on a gross basis, with the revenue component recognized in other revenues.

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

We provide gathering and/or processing services principally under contracts that contain one or more of the following arrangements:

- ***Fee-based arrangements.*** Under fee-based arrangements, we receive a fee or fees for one or more of the following services (i) natural gas gathering, treating, and/or processing and (ii) crude oil and/or produced water gathering.
- ***Percent-of-proceeds arrangements.*** Under percent-of-proceeds arrangements, we generally purchase natural gas from producers at the wellhead, or other receipt points, gather the wellhead natural gas through our gathering system, treat the natural gas, process the natural gas and/or sell the natural gas to a third party for processing. We then remit to our producers an agreed-upon percentage of the actual proceeds received from sales of the residue natural gas and NGLs. Certain of these arrangements may also result in returning all or a portion of the residue natural gas and/or the NGLs to the producer, in lieu of returning sales proceeds. The margins earned are directly related to the volume of natural gas that flows through the system and the price at which we are able to sell the residue natural gas and NGLs.

Certain of our gathering and processing agreements provide for a monthly, quarterly or annual minimum volume commitment ("MVC"). Under these MVCs, our customers agree to ship and/or process a minimum volume of production on our gathering systems or to pay a minimum monetary amount over certain periods during the term of the MVC. A customer must make a shortfall payment to us at the end of the contracted measurement period if its actual throughput volumes are less than its MVC for that period. Certain customers are entitled to utilize shortfall payments to offset gathering fees in one or more subsequent contracted measurement periods to the extent that such customer's throughput volumes in a subsequent contracted measurement period exceed its MVC for that contracted measurement period.

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

We record customer billings for obligations under their MVCs as deferred revenue when the customer has the right to utilize shortfall payments to offset gathering or processing fees in subsequent periods. We recognize deferred revenue under these arrangements in revenue once all contingencies or potential performance obligations associated with the related volumes have either (i) been satisfied through the gathering or processing of future excess volume throughput, or (ii) expired (or lapsed) through the passage of time pursuant to the terms of the applicable gathering or processing agreement. We also recognize deferred revenue when it is determined that a given amount of MVC shortfall payments cannot be recovered by offsetting gathering or processing fees in subsequent contracted measurement periods. In making this determination, we consider both quantitative and qualitative facts and circumstances, including, but not limited to, contract terms, capacity of the associated pipeline or receipt point and/or expectations regarding future investment, drilling and production.

We classify deferred revenue as a current liability for arrangements where the expiration of a customer's right to utilize shortfall payments is 12 months or less. We classify deferred revenue as noncurrent for arrangements where the expiration of the right to utilize shortfall payments and our estimate of its potential utilization is more than 12 months.

***Unit-Based Compensation.*** For awards of unit-based compensation, we determine a grant date fair value and recognize the related compensation expense in the statement of operations over the vesting period of the respective awards.

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

In general, legal entities that are chartered, organized or conducting business in the state of Texas are subject to a franchise tax (the "Texas Margin Tax"). The Texas Margin Tax has the characteristics of an income tax because it is determined by applying a tax rate to a tax base that considers both revenues and expenses. Our financial statements reflect provisions for these tax obligations.

In 2014, we elected to apply changes to the determination of cost of goods sold for the Texas Margin Tax which permits the use of accelerated depreciation allowed for federal income tax purposes. As a result of this change, we recognized a deferred tax liability. Other noncurrent liabilities included a deferred tax liability of $0.6 million and $1.6 million as of December 31, 2015 and 2014, respectively.

***Earnings or Loss Per Unit ("EPU").*** We determine basic EPU by dividing the net income or loss that is attributed, in accordance with the net income and loss allocation provisions of our partnership agreement, to limited partners under the two-class method, after deducting (i) any net income or loss of contributed subsidiaries that is attributable to Summit Investments, (ii) the general partner's 2% interest in net income or loss and (iii) any payment of IDRs, by the weighted-average number of limited partner units outstanding. Diluted EPU reflects the potential dilution that could occur if securities or other agreements to issue common units, such as unit-based compensation, were exercised, settled or converted into common units and included in the weighted-average number of units outstanding. When it is determined that potential common units resulting from an award subject to performance or market conditions should be included in the diluted EPU calculation, the impact is reflected by applying the treasury stock method.

***Comprehensive Income or Loss.*** Comprehensive income or loss is the same as net income or loss for all periods presented.

***Environmental Matters.*** We are subject to various federal, state and local laws and regulations relating to the protection of the environment. Liabilities for loss contingencies, including environmental remediation costs, arising from claims, assessments, litigation, fines, and penalties and other sources are charged to expense when it is probable that a liability has been incurred and the amount of the assessment and/or remediation can be reasonably estimated. We accrue for losses associated with environmental remediation obligations when such losses are probable and reasonably estimable. Such accruals are adjusted as further information develops or circumstances change. Recoveries of environmental remediation costs from other parties or insurers are recorded as assets when their receipt is deemed probable.

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

For drop down transactions involving assets, liabilities and expenses that were carved out of other entities, the majority of the assets and liabilities allocated to the carve-out are specifically identified based on the original entity's existing divisional organization. Depreciation and amortization are specifically identified based on the relationship of the carve-out entity to the original entity's existing divisional structure. General and administrative expenses are allocated to the carve-out entity based on an allocation of Summit Investments' consolidated expenses.

***Allocation of Certain Liabilities in Drop Downs.*** For drop down transactions involving assets for which their development was funded with debt incurred by SMP or its affiliates which was replaced with bank borrowings or debt capital at the Partnership, we allocate a portion of that debt, net of deferred loan costs, to the drop down assets during the common control period. Interest expense is allocated and recognized during the common control period. Any outstanding debt balance or principal is included in the calculation of the excess or deficit of acquired carrying value relative to consideration paid and recognized.

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

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

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

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

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

## 3. SEGMENT INFORMATION

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

- the Utica Shale, which includes our ownership interest in Ohio Gathering and also is served by Summit Utica;
- the Williston Basin, which is served by Bison Midstream, Polar and Divide and Tioga Midstream;
- the Piceance/DJ Basins, which is served by Grand River and Niobrara G&P;
- the Barnett Shale, which is served by DFW Midstream; and
- the Marcellus Shale, which is served by Mountaineer Midstream.

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.

As noted above, our investment in Ohio Gathering is included in the Utica Shale reportable segment. Segment assets for the Utica Shale includes the associated investment in equity method investees. Income or loss from equity method investees, as reflected on the statements of operations, solely relates to Ohio Gathering and is recognized and disclosed on a one-month lag (see Note 7). No other line items in the statements of operations or cash flows, as disclosed in the tables below, include results for our investment in Ohio Gathering.

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

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

Assets by reportable segment follow.

| | December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| | | (In thousands) | |
| **Assets:** | | | |
| Utica Shale (1) | $ 886,224 | $ 735,587 | $ — |
| Williston Basin | 740,361 | 861,461 | 680,014 |
| Piceance/DJ Basins | 866,095 | 941,382 | 936,794 |
| Barnett Shale | 416,586 | 428,935 | 431,578 |
| Marcellus Shale | 233,116 | 243,884 | 214,379 |
| Total reportable segment assets | 3,142,382 | 3,211,249 | 2,262,765 |
| Corporate | 22,290 | 31,213 | 19,281 |
| Total assets | $ 3,164,672 | $ 3,242,462 | $ 2,282,046 |

(1) Represents the investment in equity method investees for Ohio Gathering (see Note 7) and total assets for Summit Utica.

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

Revenues by reportable segment follow.

| | Year ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| | | (In thousands) | |
| **Revenues:** | | | |
| Utica Shale | $ 4,700 | $ 190 | $ — |
| Williston Basin | 98,929 | 109,807 | 81,501 |
| Piceance/DJ Basins | 180,418 | 161,477 | 129,747 |
| Barnett Shale | 88,042 | 93,001 | 105,324 |
| Marcellus Shale | 28,468 | 22,694 | 9,588 |
| Total reportable segment revenues and total revenues | $ 400,557 | $ 387,169 | $ 326,160 |

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

| | Year ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| **Percentage of total revenues (1):** | | | |
| Counterparty A - Piceance/DJ Basins | 16% | 18% | 19% |
| Counterparty B - Piceance/DJ Basins | 14% | * | * |
| Counterparty C - Barnett Shale | * | * | 14% |

(1) Includes recognition of revenue that was previously deferred in connection with minimum volume commitments (see Notes 2 and 8).
* Less than 10%

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

| | Year ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| | | (In thousands) | |
| **Depreciation and amortization:** | | | |
| Utica Shale | $ 1,417 | $ — | $ — |
| Williston Basin | 31,376 | 24,027 | 16,669 |
| Piceance/DJ Basins | 47,433 | 42,959 | 36,185 |
| Barnett Shale | 16,392 | 16,601 | 14,961 |
| Marcellus Shale | 8,682 | 7,648 | 3,998 |
| Total reportable segment depreciation and amortization | 105,300 | 91,235 | 71,813 |
| Corporate | 603 | 587 | 451 |
| Total depreciation and amortization | $ 105,903 | $ 91,822 | $ 72,264 |

Capital expenditures by reportable segment follow.

| | Year ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| | | (In thousands) | |
| **Capital expenditures:** | | | |
| Utica Shale | $ 94,994 | $ 24,787 | $ — |
| Williston Basin | 147,477 | 227,283 | 129,236 |
| Piceance/DJ Basins | 21,144 | 42,417 | 88,104 |
| Barnett Shale | 6,875 | 14,567 | 29,534 |
| Marcellus Shale | 1,306 | 33,866 | 1,822 |
| Total reportable segment capital expenditures | 271,796 | 342,920 | 248,696 |
| Corporate | 429 | 460 | 930 |
| Total capital expenditures | $ 272,225 | $ 343,380 | $ 249,626 |

We assess the performance of our reportable segments based on segment adjusted EBITDA. We define segment adjusted EBITDA as total revenues less total costs and expenses; plus (i) other income excluding interest income, (ii) our proportional adjusted EBITDA for equity method investees, (iii) depreciation and amortization, (iv) adjustments related to MVC shortfall payments, (v) impairments and (vi) other noncash expenses or losses, less other noncash income or gains. We define proportional adjusted EBITDA for our equity method investees as the product of total revenues less total expenses, plus amortization for deferred contract costs multiplied by our ownership interest in Ohio Gathering during the respective period.

Segment adjusted EBITDA by reportable segment follows.

| | Year ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| | | (In thousands) | |
| **Reportable segment adjusted EBITDA:** | | | |
| Utica Shale (1) | $ 35,873 | $ 6,176 | $ — |
| Williston Basin | 34,008 | 30,009 | 17,350 |
| Piceance/DJ Basins | 110,222 | 110,763 | 79,687 |
| Barnett Shale | 59,526 | 60,528 | 69,473 |
| Marcellus Shale | 23,214 | 15,940 | 6,333 |
| Total reportable segment adjusted EBITDA | $ 262,843 | $ 223,416 | $ 172,843 |

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(1) Includes our proportional share of adjusted EBITDA for Ohio Gathering and is reflected as the proportional adjusted EBITDA for equity method investees in the reconciliation of income or loss before income taxes to segment adjusted EBITDA.

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

| | Year ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| | | (In thousands) | |
| **Reconciliation of income (loss) before income taxes to segment adjusted EBITDA:** | | | |
| (Loss) income before income taxes | $ (216,268) | $ (29,802) | $ 47,737 |
| **Add:** | | | |
| Allocated corporate expenses | 27,352 | 15,441 | 10,153 |
| Interest expense | 59,092 | 48,586 | 21,314 |
| Depreciation and amortization | 105,903 | 91,822 | 72,264 |
| Proportional adjusted EBITDA for equity method investees | 33,667 | 6,006 | — |
| Adjustments related to MVC shortfall payments | (11,902) | 26,565 | 17,025 |
| Unit-based and noncash compensation | 7,017 | 5,841 | 4,242 |
| Loss on asset sales | 42 | 442 | 113 |
| Long-lived asset impairment | 9,305 | 5,505 | — |
| Goodwill impairment | 248,851 | 54,199 | — |
| **Less:** | | | |
| Interest income | 2 | 4 | 5 |
| Gain on asset sales | 214 | — | — |
| Impact of purchase price adjustment | — | 1,185 | — |
| Total reportable segment adjusted EBITDA | $ 262,843 | $ 223,416 | $ 172,843 |

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

Adjustments related to MVC shortfall payments account for:

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

Adjustments related to MVC shortfall payments by reportable segment follow.

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

## 4. PROPERTY, PLANT, AND EQUIPMENT, NET

Details on property, plant, and equipment follow.

| | December 31, | |
|---|---|---|
| | 2015 | 2014 |
| | (In thousands) | |
| Gathering and processing systems and related equipment | $ 1,883,139 | $ 1,630,250 |
| Construction in progress | 75,132 | 48,500 |
| Land and line fill | 11,055 | 11,057 |
| Other | 32,427 | 58,375 |
| Total | 2,001,753 | 1,748,182 |
| Less accumulated depreciation | 188,970 | 125,542 |
| Property, plant, and equipment, net | $ 1,812,783 | $ 1,622,640 |

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

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

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

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

Depreciation expense and capitalized interest follow.

| | Year ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| | (In thousands) | | |
| Depreciation expense | $ 63,915 | $ 53,064 | $ 37,947 |
| Capitalized interest | 3,372 | 4,646 | 6,690 |

## 5. AMORTIZING INTANGIBLE ASSETS AND UNFAVORABLE GAS GATHERING CONTRACT

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

| | December 31, 2015 | | | |
|---|---|---|---|---|
| | Useful lives (In years) | Gross carrying amount | Accumulated amortization | Net |
| | | (Dollars in thousands) | | |
| Favorable gas gathering contracts | 18.7 | $ 24,195 | $ (9,534) | $ 14,661 |
| Contract intangibles | 12.5 | 426,464 | (111,052) | 315,412 |
| Rights-of-way | 26.3 | 150,143 | (18,906) | 131,237 |
| Total intangible assets | | $ 600,802 | $ (139,492) | $ 461,310 |
| Unfavorable gas gathering contract | 10.0 | $ 10,962 | $ (6,077) | $ 4,885 |

| | December 31, 2014 | | | |
|---|---|---|---|---|
| | Useful lives (In years) | Gross carrying amount | Accumulated amortization | Net |
| | | (Dollars in thousands) | | |
| Favorable gas gathering contracts | 18.7 | $ 24,195 | $ (8,056) | $ 16,139 |
| Contract intangibles | 12.5 | 426,464 | (75,713) | 350,751 |
| Rights-of-way | 27.0 | 135,435 | (13,043) | 122,392 |
| Total intangible assets | | $ 586,094 | $ (96,812) | $ 489,282 |
| Unfavorable gas gathering contract | 10.0 | $ 10,962 | $ (5,385) | $ 5,577 |

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

We recognized amortization expense in other revenues as follows:

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

We recognized amortization expense in costs and expenses as follows:

| | Year ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| | | (In thousands) | |
| Amortization expense – contract intangibles | $ 35,339 | $ 32,554 | $ 28,654 |
| Amortization expense – rights-of-way | 5,863 | 5,260 | 4,631 |

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

| | Intangible assets | Unfavorable gas gathering contract |
|---|---|---|
| | (In thousands) | |
| 2016 | $ 43,108 | $ 924 |
| 2017 | 41,959 | 1,047 |
| 2018 | 41,413 | 1,035 |
| 2019 | 41,659 | 1,045 |
| 2020 | 44,305 | 834 |

## 6. GOODWILL

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

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

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

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

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

As discussed in Note 2, we evaluate goodwill for impairment annually on September 30 and whenever events or circumstances indicate that it is more likely than not that the fair value of a reporting unit is less than its carrying value, including goodwill.

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

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

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

In connection therewith, we reperformed our step one analyses for each as of December 31, 2014. To estimate the fair value of the reporting units, we utilized two valuation methodologies: the market approach and the income approach.

The results of our step one goodwill impairment testing indicated that the fair value of the Polar and Divide reporting unit exceeded its carrying value, including goodwill as of December 31, 2014. As a result, there was no associated impairment of goodwill in connection with the fourth quarter 2014 triggering event.

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

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

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

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

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

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

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

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

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

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

## 7. EQUITY METHOD INVESTMENTS

Ohio Gathering owns, operates and is currently developing midstream infrastructure consisting of a liquids-rich natural gas gathering system, a dry natural gas gathering system and a condensate stabilization facility in the Utica Shale Play in southeastern Ohio. Ohio Gathering provides gathering services pursuant to primarily long-term, fee-based gathering agreements, which include acreage dedications.

In January 2014, Summit Investments acquired a 1.0% ownership interest in Ohio Gathering from Blackhawk Midstream, LLC ("Blackhawk") for $190.0 million. Concurrent with this acquisition, Summit Investments made an $8.4 million capital contribution to Ohio Gathering to maintain its 1.0% ownership interest.

The ownership interest Summit Investments acquired from Blackhawk included an option to increase the holder's ownership interest in Ohio Gathering to 40.0% (the "Option"). In May 2014, Summit Investments exercised the Option to increase its ownership to 40.0% (the "Option Exercise") and made the following payments (i) $326.6 million of capital contribution true-ups, (ii) $50.4 million of additional capital contributions to maintain its 40.0% ownership interest, and (iii) $5.4 million of management fee payments that were recognized as capital contributions in its Ohio Gathering capital accounts. Concurrent with and subsequent to the Option Exercise, the non-affiliated owners have retained their respective 60.0% ownership interest in Ohio Gathering (the "Non-affiliated Owners").

Summit Investments accounted for its initial ownership interests in Ohio Gathering under the cost method due to its ownership percentage and because it determined that it was not the primary beneficiary. Subsequent to the Option Exercise, Summit Investments accounted for its ownership interests in Ohio Gathering as equity method investments because it had joint control with the Non-affiliated Owners, which gave it significant influence. This shift from the cost method to the equity method required that Summit Investments retrospectively reflect its investment in Ohio Gathering and the associated results of operations as if it had been utilizing the equity method since the inception of its investment.

Summit Investments recognized the $190.0 million that it paid to Blackhawk as an investment in Ohio Gathering at inception. In addition, Ohio Gathering had assigned a value of $7.5 million to the Option, recognized it initially as an asset and concurrently attributed the value of the Option to Blackhawk's capital account. Upon acquiring Blackhawk's interest, the Option was reclassified from Blackhawk's capital account to Summit Investments' capital account in Ohio Gathering's records. Neither of these transactions involved a flow of funds to or from Ohio Gathering. As such, they created a basis difference between its recorded investment in equity method investees and that recognized and attributed to Summit Investments by Ohio Gathering. In accordance with the retrospective recognition triggered by the Option Exercise, in February 2014, Summit Investments began amortizing these basis differences over the weighted-average remaining life of the contracts underlying Ohio Gathering's operations. The impact of amortizing these two basis differences resulted in a net decrease to Summit Investments' investment in equity method investees.

Subsequent to the Option Exercise, Summit Investments continued to make capital contributions to Ohio Gathering along with receiving distributions such that it maintained its 40.0% ownership interest through the 2016 Drop Down. Subsequent to the 2016 Drop Down, SMLP began making contributions and receiving distributions and will also continue amortizing the two basis differences, as noted above.

A rollforward of the investment in equity method investees follows.

| | 2015 | 2014 |
|---|---|---|
| | (In thousands) | |
| **Investment in equity method investees, January 1** | $ 706,172 | $ — |
| Cash contributions | 86,200 | 145,131 |
| Cash distributions | (34,641) | (2,992) |
| Gain (loss) from equity method investees | 6,790 | (4,472) |
| Amortization of basis difference in equity method investees | (13,353) | (12,240) |
| Acquisition of initial interest in Ohio Gathering | — | 190,000 |
| January 2014 initial cash contribution | — | 8,360 |
| Option Exercise | — | 382,385 |
| **Investment in equity method investees, December 31** | 751,168 | 706,172 |
| December cash distributions | 3,472 | — |
| December cash contributions | — | (20,420) |
| Basis difference | (156,888) | (170,241) |
| **Investment in equity method investees, net of basis difference, November 30** | $ 597,752 | $ 515,511 |

The following table presents summarized balance sheet information for Ohio Gathering.

| | November 30, | |
|---|---|---|
| | 2015 | 2014 |
| | (In thousands) | |
| Total assets | $ 1,510,075 | $ 1,341,007 |
| Total liabilities | 59,313 | 95,391 |
| Members' equity | 1,450,762 | 1,245,616 |

The following table presents summarized statements of operations information for Ohio Gathering for the twelve months ended November 30, 2015 and for the period of ownership in 2014.

| | Twelve months ended November 30, 2015 | Ten months ended November 30, 2014 |
|---|---|---|
| | (In thousands) | |
| Total revenues | $ 130,090 | $ 45,313 |
| Total operating expenses | 112,581 | 66,374 |
| Net income (loss) | 16,803 | (21,061) |

## 8. DEFERRED REVENUE

The majority of our gas gathering agreements provide for a monthly, quarterly or annual MVC from our customers. The amount of the shortfall payment is based on the difference between the actual throughput volume shipped or processed for the applicable period and the MVC for the applicable period, multiplied by the applicable gathering or processing fee.

Many of our gas gathering agreements contain provisions that can reduce or delay the cash flows that we expect to receive from our MVCs to the extent that a customer's actual throughput volumes are above or below its MVC for the applicable contracted measurement period. These provisions include the following:

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

A rollforward of current deferred revenue follows.

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

A rollforward of noncurrent deferred revenue follows.

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

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

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

## 9. DEBT

Debt consisted of the following:

| | December 31, | |
|---|---|---|
| | 2015 | 2014 |
| | (In thousands) | |
| Summit Holdings variable rate senior secured revolving credit facility (2.93% at December 31, 2015 and 2.67% at December 31, 2014) due November 2018 | $ 344,000 | $ 208,000 |
| Summit Holdings 5.50% Senior unsecured notes due August 2022 | 300,000 | 300,000 |
| Less unamortized deferred loan costs (1) | (4,139) | (4,773) |
| Summit Holdings 7.50% Senior unsecured notes due July 2021 | 300,000 | 300,000 |
| Less unamortized deferred loan costs (1) | (5,091) | (6,020) |
| SMP Holdings variable rate senior secured revolving credit facility (2.43% at December 31, 2015 and 2.17% at December 31, 2014) due February 2019 (2) | 115,000 | 35,000 |
| SMP Holdings variable rate senior secured term loan (2.43% at December 31, 2015 and 2.17% at December 31, 2014) due May 2017 (2) | 217,500 | 400,000 |
| Total long-term debt | $ 1,267,270 | $ 1,232,207 |

(1) Issuance costs are being amortized over the life of the notes.
(2) Debt was allocated to the 2016 Drop Down Assets prior to the closing of the 2016 Drop Down but was retained by Summit Investments after Initial Close.

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

| | Debt |
|---|---|
| | (In thousands) |
| 2016 | $ — |
| 2017 (1) | 217,500 |
| 2018 | 344,000 |
| 2019 (1) | 115,000 |
| 2020 | — |
| Thereafter | 600,000 |
| Total long-term debt | $ 1,276,500 |

(1) Debt was allocated to the 2016 Drop Down Assets prior to the closing of the 2016 Drop Down but was retained by Summit Investments after Initial Close.

***Revolving Credit Facility.*** Summit Holdings has a senior secured revolving credit facility which allows for revolving loans, letters of credit and swingline loans (the "revolving credit facility"). The revolving credit facility has a $700.0 million borrowing capacity, matures in November 2018, and includes a $200.0 million accordion feature. It is secured by the membership interests of Summit Holdings and those of its subsidiaries. Substantially all of Summit Holdings' and its subsidiaries' assets are pledged as collateral under the revolving credit facility. The revolving credit facility, and Summit Holdings' obligations, are guaranteed by SMLP and each of its subsidiaries.

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

The revolving credit facility contains affirmative and negative covenants customary for credit facilities of its size and nature that, among other things, limit or restrict the ability to: (i) incur additional debt; (ii) make investments; (iii) engage in certain mergers, consolidations, acquisitions or sales of assets; (iv) enter into swap agreements and power purchase agreements; (v) enter into leases that would cumulatively obligate payments in excess of $30.0 million over any 12-month period; and (vi) prohibits the payment of distributions by Summit Holdings if a default then exists or would result therefrom, and otherwise limits the amount of distributions Summit Holdings can make. In addition, the revolving credit facility requires Summit Holdings to maintain a ratio of consolidated trailing 12-month earnings before interest, income taxes, depreciation and amortization ("EBITDA," as defined in the credit agreement) to net interest expense of not less than 2.5 to 1.0 (as defined in the credit agreement) and a ratio of total net indebtedness to consolidated trailing 12-month EBITDA of not more than 5.0 to 1.0, or not more than 5.5 to 1.0 for up to 270 days following certain acquisitions. Additionally, the total leverage ratio upper limit can be increased from 5.0 to 1.0 to 5.5 to 1.0 at our option, subject to the inclusion of a senior secured leverage ratio (senior secured net indebtedness to consolidated trailing 12-month EBITDA, as defined in the credit agreement) upper limit of 3.75 to 1.0.

On February 25, 2016, we closed on an amendment to the revolving credit facility, which became effective concurrent with the Initial Close of the 2016 Drop Down. In connection with this amendment, (i) the revolving credit facility's borrowing capacity increased from $700.0 million to $1.25 billion, (ii) a new investment basket allowing the Co-Issuers (as defined below) to buy back up to $100.0 million of our outstanding senior unsecured notes was included (iii) the total leverage ratio was increased to 5.50 to 1.0 through December 31, 2016 and (iv) various amendments were approved to facilitate the 2016 Drop Down. There was no change to the pricing or the maturity date of the revolving credit facility in connection with this amendment.

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

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

SMLP and all of its subsidiaries other than the Co-Issuers (the "Guarantors") have fully and unconditionally and jointly and severally guaranteed the 5.5% senior notes and the 7.5% senior notes. SMLP has no independent assets or operations. Summit Holdings has no assets or operations other than its ownership of its wholly owned subsidiaries and activities associated with its borrowings under the revolving credit facility, the 5.5% senior notes and the 7.5% senior notes. Finance Corp. has no independent assets or operations and was formed for the sole purpose of being a co-issuer of certain of Summit Holdings' indebtedness, including the 5.5% senior notes and the 7.5% senior notes. There are no significant restrictions on the ability of SMLP or Summit Holdings to obtain funds from its subsidiaries by dividend or loan.

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

At any time prior to August 15, 2017, the Co-Issuers may redeem up to 35% of the aggregate principal amount of the 5.5% senior notes at a redemption price of 105.500% of the principal amount of the 5.5% senior notes, plus accrued and unpaid interest, if any, to the redemption date, with an amount not greater than the net cash proceeds of certain equity offerings. On and after August 15, 2017, the Co-Issuers may redeem all or part of the 5.5% senior notes at a redemption price of 104.125% (with the redemption premium declining ratably each year to 100.000% on and after August 15, 2020), plus accrued and unpaid interest, if any. Debt issuance costs of $5.1 million are being amortized over the life of the senior notes.

The 5.5% senior notes' indenture restricts SMLP’s and the Co-Issuers’ ability and the ability of certain of their subsidiaries to: (i) incur additional debt or issue preferred stock; (ii) make distributions, repurchase equity or redeem subordinated debt; (iii) make payments on subordinated indebtedness; (iv) create liens or other encumbrances; (v) make investments, loans or other guarantees; (vi) sell or otherwise dispose of a portion of their assets; (vii) engage in transactions with affiliates; and (viii) make acquisitions or merge or consolidate with another entity. These covenants are subject to a number of important exceptions and qualifications. At any time when the senior notes are rated investment grade by each of Moody’s Investors Service, Inc. and Standard & Poor’s Ratings Services and no default or event of default under the indenture has occurred and is continuing, many of these covenants will terminate.

The 5.5% senior notes' indenture provides that each of the following is an event of default: (i) default for 30 days in the payment when due of interest on the 5.5% senior notes; (ii) default in the payment when due of the principal of, or premium, if any, on the 5.5% senior notes; (iii) failure by the Co-Issuers or SMLP to comply with certain covenants relating to mergers and consolidations, change of control or asset sales; (iv) failure by SMLP for 180 days after notice to comply with certain covenants relating to the filing of reports with the SEC; (v) failure by the Co-Issuers or SMLP for 30 days after notice to comply with any of the other agreements in the indenture; (vi) specified defaults under any mortgage, indenture or instrument under which there may be issued or by which there may be secured or evidenced any indebtedness for money borrowed by SMLP or any of its restricted subsidiaries (or the payment of which is guaranteed by SMLP or any of its restricted subsidiaries); (vii) failure by SMLP or any of its restricted subsidiaries to pay certain final judgments aggregating in excess of $20.0 million; (viii) except as permitted by the indenture, any guarantee of the senior notes shall cease for any reason to be in full force and effect or any guarantor, or any person acting on behalf of any guarantor, shall deny or disaffirm its obligations under its guarantee of the senior notes; and (ix) certain events of bankruptcy, insolvency or reorganization described in the indenture. In the case of an event of default as described in the foregoing clause (ix), all outstanding 5.5% senior notes will become due and payable immediately without further action or notice. If any other event of default occurs and is continuing, the trustee or the holders of at least 25% in principal amount of the then outstanding 5.5% senior notes may declare all the 5.5% senior notes to be due and payable immediately.

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

<u>7.5% Senior Notes</u>. The 7.5% senior notes were sold within the United States only to qualified institutional buyers in reliance on Rule 144A under the Securities Act of 1933, as amended (the "Securities Act"), and outside the United States only to non-U.S. persons in reliance on Regulation S under the Securities Act.

We pay interest on the 7.5% senior notes semi-annually in cash in arrears on January 1 and July 1 of each year. The 7.5% senior notes are senior, unsecured obligations and rank equally in right of payment with all of our existing and future senior obligations. The 7.5% senior notes are effectively subordinated in right of payment to all of our secured indebtedness, to the extent of the collateral securing such indebtedness. We used the proceeds from the issuance of the 7.5% senior notes to repay a portion of the balance outstanding under our revolving credit facility.

Effective as of April 7, 2014, all of the holders of our 7.5% senior notes exchanged their unregistered senior notes and the guarantees of those notes for registered notes and guarantees. The terms of the registered senior notes are substantially identical to the terms of the unregistered senior notes, except that the transfer restrictions, registration rights and provisions for additional interest relating to the unregistered senior notes do not apply to the registered senior notes.

At any time prior to July 1, 2016, the Co-Issuers may redeem up to 35% of the aggregate principal amount of the 7.5% senior notes at a redemption price of 107.500% of the principal amount of the 7.5% senior notes, plus accrued and unpaid interest, if any, to the redemption date, with an amount not greater than the net cash proceeds of certain equity offerings. On and after July 1, 2016, the Co-Issuers may redeem all or part of the 7.5% senior notes at a redemption price of 105.625% (with the redemption premium declining ratably each year to 100.000% on and after July 1, 2019), plus accrued and unpaid interest, if any. Debt issuance costs of $7.4 million are being amortized over the life of the senior notes.

The 7.5% senior notes indenture restricts SMLP’s and the Co-Issuers’ ability and the ability of certain of their subsidiaries to: (i) incur additional debt or issue preferred stock; (ii) make distributions, repurchase equity or redeem subordinated debt; (iii) make payments on subordinated indebtedness; (iv) create liens or other encumbrances; (v) make investments, loans or other guarantees; (vi) sell or otherwise dispose of a portion of their assets; (vii) engage in transactions with affiliates; and (viii) make acquisitions or merge or consolidate with another entity. These covenants are subject to a number of important exceptions and qualifications. At any time when the senior notes are rated investment grade by each of Moody’s Investors Service, Inc. and Standard & Poor’s Ratings Services and no default or event of default under the indenture has occurred and is continuing, many of these covenants will terminate.

The 7.5% senior notes indenture provides that each of the following is an event of default: (i) default for 30 days in the payment when due of interest on the 7.5% senior notes; (ii) default in the payment when due of the principal of, or premium, if any, on the 7.5% senior notes; (iii) failure by the Co-Issuers or SMLP to comply with certain covenants relating to mergers and consolidations, change of control or asset sales; (iv) failure by SMLP for 180 days after notice to comply with certain covenants relating to the filing of reports with the SEC; (v) failure by the Co-

Issuers or SMLP for 30 days after notice to comply with any of the other agreements in the indenture; (vi) specified defaults under any mortgage, indenture or instrument under which there may be issued or by which there may be secured or evidenced any indebtedness for money borrowed by SMLP or any of its restricted subsidiaries (or the payment of which is guaranteed by SMLP or any of its restricted subsidiaries); (vii) failure by SMLP or any of its restricted subsidiaries to pay certain final judgments aggregating in excess of $20.0 million; (viii) except as permitted by the indenture, any guarantee of the senior notes shall cease for any reason to be in full force and effect or any guarantor, or any person acting on behalf of any guarantor, shall deny or disaffirm its obligations under its guarantee of the 7.5% senior notes; and (ix) certain events of bankruptcy, insolvency or reorganization described in the indenture. In the case of an event of default as described in the foregoing clause (ix), all outstanding 7.5% senior notes will become due and payable immediately without further action or notice. If any other event of default occurs and is continuing, the trustee or the holders of at least 25% in principal amount of the then outstanding 7.5% senior notes may declare all the 7.5% senior notes to be due and payable immediately.

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

***SMP Holdings Credit Facility.*** In March 2013, SMP Holdings closed on a $150.0 million senior secured revolving credit facility (the "SMP Revolving Credit Facility") and a $200.0 million senior secured term loan (the "Term Loan" and, collectively with the SMP Revolving Credit Facility, the "SMP Holdings Credit Facility"). Borrowings under the SMP Holdings Credit Facility incurred interest at LIBOR or a base rate (as defined in the SMP Holdings Credit Facility) plus an applicable margin. Because the funding was used to support the development of the 2016 Drop Down Assets, Summit Investments allocated the SMP Holdings Credit Facility to the Partnership during the years ended December 31, 2015, 2014 and 2013.

In February 2014, SMP Holdings closed on an amendment and restatement of the SMP Holdings Credit Facility whereby it:

(i) increased the borrowing capacity from $150.0 million to $250.0 million;

(ii) extended the maturity date from March 2018 to February 2019;

(iii) added a $100.0 million revolving credit facility accordion feature and a $400.0 million term loan accordion;

(iv) reduced the leverage-based pricing grid by 0.75% from a range of 2.75% to 3.75% to a new range of 2.00% to 3.00% for LIBOR borrowings and from a range of 1.75% to 2.75% to a new range of 1.00% to 2.00% for alternate base rate borrowings;

(v) changed the commitment fee from 0.50% to a leverage-based range of 0.30% to 0.50%; and

(vi) increased the maximum total leverage ratio from 4.0 to 1.0 to 5.0 to 1.0 and from not more than 5.0 to 1.0 to 5.5 to 1.0 for up to 270 days following certain acquisitions, or material projects or, at its option, after a qualified notes offering (as defined in the SMP Holdings Credit Facility).

In March 2014, Summit Investments used the proceeds from its offering of SMLP common units to repay the remaining $100.0 million balance on the then-outstanding Term Loan as well as $95.0 million then outstanding under the SMP Revolving Credit Facility. It wrote off $1.5 million of deferred loan costs in connection with these repayments. In May 2014, Summit Investments borrowed $400.0 million pursuant to the Term Loan accordion (the "Incremental Term Loan"). In May 2015, it repaid $175.0 million of the Incremental Term Loan and wrote off $0.7 million of deferred loan costs in connection therewith.

On March 3, 2016, the remaining balances on the SMP Revolving Credit Facility and the Incremental Term Loan were repaid in full and the SMP Holdings Credit Facility was terminated concurrent with the closing of the 2016 Drop Down (see Note 16).

The SMP Holdings Credit Facility contained affirmative and negative covenants customary for credit facilities of its size and nature. As of December 31, 2015, Summit Investments was in compliance with the covenants in the SMP Holdings Credit Facility. There were no defaults or events of default during the year ended December 31, 2015 or during the period from December 31, 2015 to the March 3, 2016 termination of the SMP Holdings Credit Facility.

## 10. FINANCIAL INSTRUMENTS

***Concentrations of Credit Risk.*** Financial instruments that potentially subject us to concentrations of credit risk consist of cash and accounts receivable. We maintain our cash in bank deposit accounts that frequently exceed federally insured limits. We have not experienced any losses in such accounts and do not believe we are exposed to any significant risk.

Accounts receivable primarily comprise amounts due for the gathering, treating and processing services we provide to our customers and also the sale of natural gas liquids resulting from our processing services. This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers may be similarly affected by changes in economic, industry or other conditions. We monitor the creditworthiness of our counterparties and can require letters of credit for receivables from counterparties that are judged to have substandard credit, unless the credit risk can otherwise be mitigated. Our top five customers or counterparties accounted for 68% of total accounts receivable at December 31, 2015, compared with 57% as of December 31, 2014.

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

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

| | December 31, 2015 | | December 31, 2014 | |
|---|---|---|---|---|
| | Carrying value | Estimated fair value (Level 2) | Carrying value | Estimated fair value (Level 2) |
| | (In thousands) | | | |
| Summit Holdings revolving credit facility | $ 344,000 | $ 344,000 | $ 208,000 | $ 208,000 |
| Summit Holdings 5.5% senior notes ($300.0 million principal) | 295,861 | 224,000 | 295,227 | 281,750 |
| Summit Holdings 7.5% senior notes ($300.0 million principal) | 294,909 | 257,000 | 293,980 | 306,750 |
| SMP Holdings revolving credit facility (1) | 115,000 | 115,000 | 35,000 | 35,000 |
| SMP Holdings term loan (1) | 217,500 | 217,500 | 400,000 | 400,000 |

(1) Debt was allocated to the 2016 Drop Down Assets prior to the closing of the 2016 Drop Down but was retained by Summit Investments after Initial Close.

The carrying value on the balance sheet of each revolving credit facility and the term loan is its fair value due to its floating interest rate. The fair value for the senior notes is based on an average of nonbinding broker quotes as of December 31, 2015 and December 31, 2014. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value of the senior notes.

### 11. PARTNERS' CAPITAL

A rollforward of the number of common limited partner, subordinated limited partner and general partner units follows.

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

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

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

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

***Subordination.*** The principal difference between our common units and subordinated units is that in any quarter during the subordination period, holders of the subordinated units are not entitled to receive any distribution of available cash until the common units have received the minimum quarterly distribution ("MQD," as defined below) plus any arrearages in the payment of the MQD from prior quarters. The subordination period ends on the first business day after we have earned and paid at least $1.60 (the MQD on an annualized basis) on each outstanding common unit and subordinated unit and the corresponding distribution on the general partner's 2.0% interest for each of three consecutive, non-overlapping four-quarter periods ending on or after December 31, 2015. The subordination period ended in conjunction with the February 2016 distribution payment in respect of the fourth quarter of 2015 and the then-outstanding subordinated units converted to common units on a one-for-one basis.

***Summit Investments' Equity in Contributed Subsidiaries.*** Summit Investments' equity in contributed subsidiaries represents its position in the net assets of the 2016 Drop Down Assets, Polar and Divide, Red Rock Gathering and Bison Midstream that have been acquired by SMLP. The balance also reflects net income attributable to Summit Investments for the 2016 Drop Down Assets, Polar and Divide, Red Rock Gathering and Bison Midstream for the periods beginning on their respective acquisition dates by Summit Investments and ending on the dates they were acquired by the Partnership. During the years ended December 31, 2015, 2014 and 2013, net income was attributed to Summit Investments for:

- the 2016 Drop Down Assets for the period from February 16, 2013 to March 3, 2016;
- Polar and Divide for the period from February 16, 2013 to May 18, 2015;

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

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

Polar and Divide Drop Down. On May 18, 2015, we acquired 100% of the membership interests in Polar Midstream and Epping from a subsidiary of Summit Investments. We paid total net cash consideration of $285.7 million in exchange for Summit Investments' $416.0 million net investment in Polar Midstream and Epping, including customary working capital and capital expenditures adjustments (see Note 16 for additional information). We recognized a capital contribution from Summit Investments for the difference between cash consideration paid and Summit Investments' net investment in Polar Midstream and Epping.

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

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

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

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

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

Bison Drop Down. On June 4, 2013, a subsidiary of Summit Investments entered into a purchase and sale agreement with SMLP whereby SMLP acquired the Bison Gas Gathering system. In exchange for its $305.4 million net investment in Bison Midstream, SMLP paid Summit Investments and the general partner total cash and unit consideration of $248.9 million. As a result of the contribution of net assets in excess of consideration, SMLP recognized a capital contribution from Summit Investments.

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

| | | | | |
|---|---|---|---|---|
| Summit Investments' net investment in Bison Midstream | | | $ | 305,449 |
| Aggregate cash paid to Summit Investments | $ | 200,000 | | |
| Issuance of 1,553,849 SMLP common units to Summit Investments | | 47,936 | | |
| Issuance of 31,711 SMLP general partner units to the general partner | | 978 | | |
| Total consideration paid to a subsidiary of Summit Investments | | | | 248,914 |
| Excess of acquired carrying value over consideration paid | | | $ | 56,535 |
| | | | | |
| Allocation of capital contribution: | | | | |
| General partner interest | $ | 1,131 | | |
| Common limited partner interest | | 28,558 | | |
| Subordinated limited partner interest | | 26,846 | | |
| Partners' capital contribution – excess of acquired carrying value over consideration paid | | | $ | 56,535 |

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

The general partner interest allocation was calculated based on a 2% general partner interest in the contribution of assets in excess of consideration given by SMLP to Summit Investments. Common and subordinated limited partner interests allocations were calculated as their respective percentages of total limited partner capital applied to the balance of the contribution by Summit Investments after giving effect to the general partner allocation.

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

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

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

Pursuant to a unit purchase agreement, the number of units issued to Summit Investments and the general partner in connection with the Mountaineer Acquisition was calculated based on an assumed equity issuance of $100.0 million and the five-day volume-weighted-average price as of June 3, 2013 of $31.53 per unit.

**Cash Distribution Policy**

Our cash distribution policy, as expressed in our partnership agreement, may not be modified or repealed without amending our partnership agreement. Our partnership agreement requires that we distribute all of our available cash (as defined below) within 45 days after the end of each quarter to unitholders of record on the applicable record date. Our policy is to distribute to our unitholders an amount of cash each quarter that is equal to or greater than the MQD stated in our partnership agreement.

***General Partner Interest.*** Our general partner is entitled to 2.0% of all distributions that we make prior to our liquidation. Our general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its current general partner interest. Our general partner's initial 2.0% interest in our distributions will be reduced if we issue additional units in the future and our general partner does not contribute a proportionate amount of capital to us to maintain its 2.0% general partner interest.

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

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

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

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

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

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

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

***Incentive Distribution Rights.*** Our general partner also currently holds IDRs that entitle it to receive increasing percentage allocations, up to a maximum of 50.0% (as set forth in the chart below), of the cash we distribute from operating surplus in excess of $0.46 per unit per quarter. The maximum distribution includes distributions paid to our general partner on its 2.0% general partner interest and assumes that our general partner maintains its general partner interest at 2.0%. The maximum distribution does not include any distributions that our general partner may receive on any common or subordinated units that it owns.

<u>Percentage Allocations of Available Cash</u>. The following table illustrates the percentage allocations of available cash between the unitholders and our general partner based on the specified target distribution levels. The amounts set forth in the column Marginal Percentage Interest in Distributions are the percentage interests of our general partner and the unitholders in any available cash we distribute up to and including the corresponding amount in the column Total Quarterly Distribution Per Unit Target Amount. The percentage interests shown for our unitholders and our general partner for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the minimum quarterly distribution. The percentage interests set forth below for our general partner include its 2.0% general partner interest and assume that our general partner has contributed any additional capital necessary to maintain its 2.0% general partner interest, our general partner has not transferred its IDRs and that there are no arrearages on common units.

| | Total quarterly distribution per unit target amount | Marginal percentage interest in distributions | |
|---|---|---|---|
| | | Unitholders | General partner |
| Minimum quarterly distribution | $0.40 | 98.0% | 2.0% |
| First target distribution | $0.40 up to $0.46 | 98.0% | 2.0% |
| Second target distribution | above $0.46 up to $0.50 | 85.0% | 15.0% |
| Third target distribution | above $0.50 up to $0.60 | 75.0% | 25.0% |
| Thereafter | above $0.60 | 50.0% | 50.0% |

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

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

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

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

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

## 12. EARNINGS PER UNIT

The following table details the components of EPU.

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

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

### 13. UNIT-BASED AND NONCASH COMPENSATION

***SMLP Long-Term Incentive Plan.*** The SMLP Long-Term Incentive Plan (the "SMLP LTIP") provides for equity awards to eligible officers, employees, consultants and directors of our general partner and its affiliates, thereby linking the recipients' compensation directly to SMLP's performance. The SMLP LTIP is administered by our general partner's board of directors, though such administration function may be delegated to a committee appointed by the board. A total of 5.0 million common units was reserved for issuance pursuant to and in accordance with the SMLP LTIP. As of December 31, 2015, approximately 4.4 million common units remained available for future issuance.

The SMLP LTIP provides for the granting, from time to time, of unit-based awards, including common units, restricted units, phantom units, unit options, unit appreciation rights, distribution equivalent rights, profits interest units and other unit-based awards. Grants are made at the discretion of the board of directors or compensation committee of our general partner. The administrator of the SMLP LTIP may make grants under the SMLP LTIP that contain such terms, consistent with the SMLP LTIP, as the administrator may determine are appropriate, including vesting conditions. The administrator of the SMLP LTIP may, in its discretion, base vesting on the grantee's completion of a period of service or upon the achievement of specified financial objectives or other criteria or upon a change of control (as defined in the SMLP LTIP) or as otherwise described in an award agreement. Termination of employment prior to vesting will result in forfeiture of the awards, except in limited circumstances as described in the plan documents. Units that are canceled or forfeited will be available for delivery pursuant to other awards.

The following table presents phantom and restricted unit activity:

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

A phantom unit is a notional unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit or on a deferred basis upon specified future dates or events or, in the discretion of the administrator, cash equal to the fair market value of a common unit. Distribution equivalent rights for each phantom unit provide for a lump sum cash amount equal to the accrued distributions from the grant date to be paid in cash upon the vesting date. A restricted unit is a common limited partner unit that is subject to a restricted period during which the unit remains subject to forfeiture.

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

As of December 31, 2015, the unrecognized unit-based compensation related to the SMLP LTIP was $5.5 million. Incremental unit-based compensation will be recorded over the remaining vesting period of approximately 1.17 years. Due to the limited and immaterial forfeiture history associated with the grants under the SMLP LTIP, no forfeitures were assumed in the determination of estimated compensation expense.

Unit-based compensation recognized in general and administrative expense related to awards under the SMLP LTIP follows.

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

***SMP Net Profits Interests.*** In connection with the formation of Summit Investments in 2009, up to 7.5% of total membership interests were authorized for issuance. SMP Net Profits Interests were granted through January 2012. Each grant vests ratably over five years and provides for accelerated vesting in certain limited circumstances. Summit Investments valued the SMP Net Profits Interests utilizing an option pricing method, which modeled membership interests as call options on the underlying equity value of Summit Investments and considered the rights and preferences of each class of equity to allocate a fair value to each class. Summit Investments retained the SMP Net Profits Interests and, as such, they are not reflected in SMLP's financial statements subsequent to the IPO, except as noted below.

Due to common control, we recognized the SMP Net Profits Interests' noncash compensation expense that had been allocated to the contributed subsidiaries prior to their respective drop down date. Noncash compensation recognized in general and administrative expense related to the SMP Net Profits Interests was $0.8 million in 2015, $1.1 million in 2014 and $1.2 million in 2013.

***DFW Net Profits Interests***. In connection with the formation of DFW Midstream in 2009, up to 5% of DFW Midstream's total membership interests were authorized for issuance (the "DFW Net Profits Interests"). Grants were made in 2009 and 2010. Each grant vested ratably over four years and provided for accelerated vesting in certain limited circumstances. The DFW Net Profits Interests were valued utilizing an option pricing method, which modeled membership interests as call options on the underlying equity value of DFW Midstream and considered the rights and preferences of each class of equity to allocate a fair value to each class.

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

## 14. RELATED-PARTY TRANSACTIONS

***Acquisitions.*** See Notes 1, 9, 11 and 16 for disclosure of the 2016 Drop Down, Polar and Divide Drop Down, the Red Rock Drop Down, the Bison Drop Down and the funding of those transactions.

***Reimbursement of Expenses from General Partner.*** Our general partner and its affiliates do not receive a management fee or other compensation in connection with the management of our business, but will be reimbursed for expenses incurred on our behalf. Under our partnership agreement, we reimburse our general partner and its affiliates for certain expenses incurred on our behalf, including, without limitation, salary, bonus, incentive compensation and other amounts paid to our general partner's employees and executive officers who perform services necessary to run our business. Our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us. Due to affiliate on the consolidated balance sheet represents the payables to our general partner for expenses incurred by it and paid on our behalf.

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

| | Year ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| | | (In thousands) | |
| Operation and maintenance expense | $ 25,050 | $ 22,004 | $ 15,095 |
| General and administrative expense | 26,193 | 24,993 | 21,084 |

***Expenses Incurred by Summit Investments.*** Prior to the 2016 Drop Down, the Polar and Divide Drop Down, the Red Rock Drop Down and the Bison Drop Down, Summit Investments incurred:

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

## 15. COMMITMENTS AND CONTINGENCIES

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

| | Year ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| | | (In thousands) | |
| Rent expense | $ 2,395 | $ 1,881 | $ 1,616 |

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

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

***Environmental Matters.*** Although we believe that we are in material compliance with applicable environmental regulations, the risk of environmental remediation costs and liabilities are inherent in pipeline ownership and operation. Furthermore, we can provide no assurances that significant environmental remediation costs and liabilities will not be incurred by the Partnership in the future. We are currently not aware of any material contingent liabilities that exist with respect to environmental matters, except as noted below.

In January 2015, Summit Investments learned of the rupture of a four-inch produced water gathering pipeline on the Meadowlark Midstream gathering system near Williston, North Dakota. The rupture resulted in the release of some of the produced water in the pipeline. Based on Summit Investments' investigation and currently available information, it is at least reasonably possible that the rupture occurred on or prior to December 31, 2014. As such, Summit Investments accounted for the rupture as a 2014 event.

Summit Investments took action to minimize the impact of the rupture on affected landowners, control any environmental impact, help ensure containment and clean up the affected area. The incident, which is covered by Summit Investments' insurance policies, is subject to maximum coverage of $25.0 million from its pollution liability insurance policy and $200.0 million from its property and business interruption insurance policy. Summit Investments exhausted the $25.0 million pollution liability policy in 2015. Property and business interruption claim requests have been submitted, although no amounts have been recognized for any potential recoveries, under the property and business interruption insurance policy.

| | Total |
|---|---|
| | (In thousands) |
| **Accrued environmental remediation, January 1, 2014** | $ — |
| Initial accrual | 30,000 |
| **Accrued environmental remediation, December 31, 2014** | 30,000 |
| Payments made by affiliates | (13,136) |
| Payments made with proceeds from insurance policies | (25,000) |
| Additional accruals | 21,800 |
| **Accrued environmental remediation, December 31, 2015** | $ 13,664 |

As of December 31, 2015, we have recognized (i) a current liability for remediation effort expenditures expected to be incurred within the next 12 months and (ii) a noncurrent liability for estimated remediation expenditures and fines expected to be incurred subsequent to December 31, 2016. Each of these amounts represent our best estimate for costs expected to be incurred. Neither of these amounts has been discounted to its present value.

The U.S. Department of Justice has issued subpoenas to Summit Investments, the Partnership and our general partner requesting certain materials related to the rupture. We cannot predict the ultimate outcome of this matter with certainty for Summit Investments or Meadowlark Midstream, especially as it relates to any material liability as a result of any governmental proceeding related to the incident. SMLP and its general partner did not have any management or operational control over, or ownership interest in, Meadowlark Midstream or the produced water disposal pipeline prior to the 2016 Drop Down. Furthermore, 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, including losses related to the rupture. As a result, we believe at this time that it is unlikely that SMLP or its general partner will be subject to any material liability as a result of any governmental proceeding related to the rupture.

On June 19, 2015, Summit Investments and Meadowlark Midstream received a complaint from the North Dakota Industrial Commission seeking approximately $2.5 million in fines and other fees related to the rupture. Meadowlark Midstream has accrued its best estimate of the amount to be paid for such fines and other fees and intends to vigorously defend this complaint.

## 16. ACQUISITIONS AND DROP DOWN TRANSACTIONS

***2016 Drop Down.*** On March 3, 2016, the Partnership acquired the 2016 Drop Down Assets. These assets include certain natural gas, crude oil and produced water gathering systems located in the Utica Shale, the Williston Basin and the DJ Basin as well as ownership interests in a natural gas gathering system and a condensate stabilization facility, both located in the Utica Shale.

The consideration for the 2016 Drop Down Assets (i) consisted of a cash payment to SMP Holdings of $360.0 million (the “Initial Payment”), funded with borrowings under our revolving credit facility and (ii) includes a deferred payment in 2020 (the “Deferred Purchase Price Obligation”). The Deferred Purchase Price Obligation will be equal to:

- six-and-one-half (6.5) multiplied by the average Business Adjusted EBITDA, as defined below and in the Contribution Agreement, of the 2016 Drop Down Assets for 2018 and 2019, less the G&A Adjuster, as defined in the Contribution Agreement;
- 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 Business Adjusted EBITDA from the 2016 Drop Down Assets between Initial Close and December 31, 2019, less the Cumulative G&A Adjuster, as defined in the Contribution Agreement.

Business Adjusted EBITDA is defined as the net income or loss of the 2016 Drop Down Assets for such period:

- plus interest expense, income tax expense, and depreciation and amortization of the 2016 Drop Down Assets for such period;
- plus any adjustments related to MVC shortfall payments, impairments and other noncash expenses or losses with respect to the 2016 Drop Down Assets for such period;
- plus any Special Liability Expenses, as defined below and in the Contribution Agreement, for such period;
- less interest income and income tax benefit of the 2016 Drop Down Assets for such period;
- less adjustments related to any other noncash income or gains with respect to the 2016 Drop Down Assets for such period.

Business Adjusted EBITDA shall exclude the effect of any Partnership expenses allocated by or to SMLP or its affiliates in respect of the 2016 Drop Down Assets, such as general and administrative expenses (including compensation-related expenses and professional services fees), transaction costs, and allocated interest expense and allocated income tax expense.

Special Liability Expenses are defined as any and all expenses incurred by SMLP with respect to the Special Liabilities, as defined in the Contribution Agreement, including fines, legal fees, consulting fees and remediation costs.

The present value of the Deferred Purchase Price Obligation will be reflected as a liability on our balance sheet until paid.  As of Initial Close, the Deferred Purchase Price Obligation was estimated to be $860.3 million (based on management's estimate of the Partnership's share of forecasted Business Adjusted EBITDA and capital expenditures for the 2016 Drop Down Assets) and had a net present value of $507.4 million, using a discount rate of 13%.

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

Because of the common control aspects in a drop down transaction, the 2016 Drop Down was deemed a transaction between entities under common control. As such, the 2016 Drop Down has been accounted for on an “as-if pooled” basis for all periods in which common control existed and the Partnership's financial results retrospectively include the combined financial results of the 2016 Drop Down Assets for all common-control periods.

<u>Summit Utica</u>. Summit Investments completed the acquisition of certain natural gas gathering assets located in the Utica Shale Play for $25.2 million on December 15, 2014. These assets, which were contributed to Summit Investments' then-newly formed subsidiary, Summit Utica, gather natural gas under a long-term, fee-based contract. Summit Investments accounted for the purchase under the acquisition method of accounting. As of December 31, 2014, we assigned the full purchase price to property, plant and equipment.

<u>Ohio Gathering</u>. For information on the acquisition and initial recognition of Ohio Gathering, see Note 7.

<u>Meadowlark Midstream</u>. At the time of the 2016 Drop Down, Meadowlark Midstream owned Niobrara G&P and certain crude oil and produced water gathering pipelines located in Williams County, North Dakota. Summit Investments accounted for its purchase of Meadowlark Midstream under the acquisition method of accounting, whereby the various gathering systems' identifiable tangible assets acquired were recorded based on their fair values as of initial acquisition on February 15, 2013. Both Bison Midstream and Polar Midstream have previously been carved out of Meadowlark Midstream. Their fair values were determined based upon assumptions related to future cash flows, discount rates, asset lives, and projected capital expenditures to complete the system. We recognized the 2016 acquisition of Meadowlark Midstream at Summit Investments' historical cost of construction and fair value of assets at acquisition, which reflected its fair value accounting for the initial acquisition of Meadowlark Midstream in 2013, due to common control.

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

| | | | | |
|---|---|---|---|---|
| Purchase price assigned to Meadowlark Midstream | | | $ | 25,376 |
| Current assets | $ | 2,227 | | |
| Property, plant, and equipment | | 18,795 | | |
| Other noncurrent assets | | 4,354 | | |
| Total assets acquired | | 25,376 | | |
| Total liabilities assumed | $ | — | | |
| Net identifiable assets acquired | | | $ | 25,376 |

From a financial position and operational standpoint, the crude oil and produced water gathering pipelines held by Meadowlark Midstream and acquired in connection with the 2016 Drop Down are recognized as part of the Polar and Divide gathering system.

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

Summit Investments accounted for its purchase of Meadowlark Midstream, the entity that Polar Midstream was carved out of, under the acquisition method of accounting, whereby the various gathering systems' identifiable tangible and intangible assets acquired and liabilities assumed were recorded based on their fair values as of initial acquisition on February 15, 2013. Their fair values were determined based upon assumptions related to future cash flows, discount rates, asset lives, and projected capital expenditures to complete the system. We recognized the acquisition of Polar Midstream at Summit Investments' historical cost of construction and fair value of assets and liabilities at acquisition, which reflected its fair value accounting for the acquisition of Meadowlark Midstream, due to common control.

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

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

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

***Red Rock Gathering System.*** On March 18, 2014, SMLP acquired Red Rock Gathering, a natural gas gathering and processing system located in Colorado and Utah, from a subsidiary of Summit Investments, subject to customary working capital adjustments. In October 2012, Summit Investments acquired ETC Canyon Pipeline, LLC ("Canyon") and contributed the Canyon gathering and processing assets to Red Rock Gathering, a newly formed, wholly owned subsidiary of Summit Investments. The Partnership paid total cash consideration of $307.9 million, comprising $305.0 million at the date of acquisition and $2.9 million of working capital adjustments that were recognized in due to affiliate as of December 31, 2014 and settled in February 2015. The acquisition of Red Rock Gathering was funded with the net proceeds from an offering of common units in March 2014, $100.0 million of borrowings under our revolving credit facility and cash on hand. Because of the common control aspects in the drop down transaction, the Red Rock Gathering acquisition was deemed a transaction between entities under common control and, as such, was accounted for on an “as-if pooled” basis for all periods in which common control existed. SMLP’s financial results retrospectively include Red Rock Gathering’s financial results for all periods ending after October 23, 2012, the date Summit Investments acquired its interests, and before March 18, 2014.

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

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

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

Summit Investments accounted for its purchase of BTE (the "BTE Transaction") under the acquisition method of accounting, whereby the various gathering systems' identifiable tangible and intangible assets acquired and liabilities assumed were recorded based on their fair values as of February 15, 2013. The intangible assets that were acquired are composed of gas gathering agreement contract values and rights-of-way easements. Their fair values were determined based upon assumptions related to future cash flows, discount rates, asset lives, and projected capital expenditures to complete the system.

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

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

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

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

***Mountaineer Midstream.*** We completed the Mountaineer Acquisition on June 21, 2013 for $210.0 million cash consideration. The Mountaineer Midstream natural gas gathering and compression assets are located in the

Appalachian Basin which includes the Marcellus Shale formation primarily in Doddridge and Harrison counties in northern West Virginia. The Mountaineer Midstream system consists of newly constructed, high-pressure gas gathering pipelines, certain rights-of-way associated with the pipeline, and two compressor stations. The assets gather natural gas under a long-term, fee-based contract with Antero Resources Corp. ("Antero"). The life of the acquired contract was 13 years upon acquisition.

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

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

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

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

***Supplemental Disclosures – As-If Pooled Basis.*** As a result of accounting for our drop down transactions similar to a pooling of interests, our historical financial statements and those of the 2016 Drop Down, Polar Midstream, Red Rock Gathering and the Bison Gas Gathering system have been combined to reflect the historical operations, financial position and cash flows from the date common control began. Revenues and net income for the previously separate entities and the combined amounts, as presented in these consolidated financial statements follow.

| | Year ended December 31, | | |
|---|---|---|---|
| | 2015 | 2014 | 2013 |
| | | (In thousands) | |
| SMLP revenues | $ 358,046 | $ 338,941 | $ 241,089 |
| 2016 Drop Down Assets revenues (1) | 29,238 | 14,466 | 2,474 |
| Polar and Divide revenues (1) | 13,273 | 22,449 | 3,893 |
| Red Rock Gathering revenues (1) | | 11,313 | 50,114 |
| Bison Gas Gathering system revenues (1) | | | 28,590 |
| Combined revenues | $ 400,557 | $ 387,169 | $ 326,160 |
| | | | |
| SMLP net (loss) income | $ (192,212) | $ (23,992) | $ 43,584 |
| 2016 Drop Down Assets net loss (1) | (35,419) | (32,634) | (5,829) |
| Polar and Divide net income (loss) (1) | 5,403 | 6,430 | (467) |
| Red Rock Gathering net income (1) | | 2,828 | 9,668 |
| Bison Gas Gathering system net income (1) | | | 52 |
| Combined net (loss) income | $ (222,228) | $ (47,368) | $ 47,008 |

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

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

- The acquisition of the Bison Gas Gathering system and Mountaineer Midstream occurred on January 1, 2012. The pro forma results for Bison Midstream and Mountaineer Midstream were derived from revenues and net income in 2013.
- Pro forma net income for the year ended December 31, 2013 has been adjusted to remove the impact of $2.5 million of nonrecurring transaction costs associated with the acquisitions of Bison Midstream and Mountaineer Midstream.
- Pro forma adjustments also reflect the impact of 4,661,547 common unit issuance and the general partner capital contribution to maintain its 2% general partner interest to fund the acquisition of Bison Midstream and Mountaineer Midstream.
- Pro forma adjustments also reflect the impact of $310.0 million of incremental borrowings on our revolving credit facility for the Bison Midstream and Mountaineer Midstream acquisitions and incremental depreciation and amortization expense associated with the acquired property, plant and equipment and contract intangibles as a result of the application of fair value accounting for Bison Midstream.
- Pro forma adjustments (other than an adjustment for interest expense as discussed below) for the 2016 Drop Down Assets are not required because the assets were not in service prior to common control beginning in February 2013. Interest expense was assumed based on the impact of $360.0 million of incremental borrowings on our revolving credit facility, partially offset by the pro forma derecognition of interest expense allocated to the 2016 Drop Down Assets from Summit Investments (see Note 9).
- Pro forma adjustments for Polar and Divide are not required because the system was not in service prior to common control beginning in February 2013.
- The acquisition of the Lonestar assets is immaterial for pro forma purposes and as such has not been reflected below.

| | Year ended December 31, 2013 (In thousands, except for per-unit amounts) |
|---|---|
| Total Bison Midstream and Mountaineer Midstream revenues included in consolidated revenues | $ 87,196 |
| Total Bison Midstream and Mountaineer Midstream net loss included in consolidated net income | (457) |
| | |
| Pro forma total revenues | $ 338,311 |
| Pro forma net income | 34,369 |
| | |
| Pro forma common EPU - basic and diluted | $ 0.68 |
| Pro forma subordinated EPU - basic and diluted | 0.62 |

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

## 17. UNAUDITED QUARTERLY FINANCIAL DATA

Summarized information on the consolidated results of operations for each of the quarters during the two-year period ended December 31, 2015, follows.

| | Quarter ended December 31, 2015 | Quarter ended September 30, 2015 | Quarter ended June 30, 2015 | Quarter ended March 31, 2015 |
|---|---|---|---|---|
| | (In thousands, except per-unit amounts) | | | |
| Total revenues (1) | $ 112,414 | $ 115,201 | $ 86,855 | $ 86,087 |
| Net (loss) income attributable to SMLP (2)(3) | $ (220,468) | $ 23,604 | $ 2,985 | $ 1,667 |
| Less net (loss) income attributable to general partner, including IDRs | (2,469) | 2,408 | 1,891 | 1,568 |
| Net (loss) income attributable to limited partners | $ (217,999) | $ 21,196 | $ 1,094 | $ 99 |
| **(Loss) earnings per limited partner unit:** | | | | |
| Common unit – basic | $ (3.28) | $ 0.32 | $ 0.05 | $ 0.00 |
| Common unit – diluted | $ (3.28) | $ 0.32 | $ 0.05 | $ 0.00 |
| Subordinated unit – basic and diluted | $ (3.28) | $ 0.32 | $ (0.03) | $ 0.00 |

(1) Retrospectively adjusted for the impact of the 2016 Drop Down, the Polar and Divide Drop Down and the reclassification of certain revenues for Bison Midstream.
(2) In the quarter ended December 31, 2015, net loss attributable to SMLP includes $248.9 million of goodwill impairments and $1.6 million of long-lived asset impairments.
(3) In the quarter ended September 30, 2015, net income attributable to SMLP includes $7.7 million of long-lived asset impairments.

| | Quarter ended December 31, 2014 | Quarter ended September 30, 2014 | Quarter ended June 30, 2014 | Quarter ended March 31, 2014 |
|---|---|---|---|---|
| | (In thousands, except per-unit amounts) | | | |
| Total revenues (1) | $ 114,252 | $ 94,152 | $ 93,063 | $ 85,702 |
| Net (loss) income attributable to SMLP (2) | $ (37,686) | $ 6,113 | $ 4,036 | $ 3,545 |
| Less net (loss) income attributable to general partner, including IDRs | 689 | 1,204 | 801 | 431 |
| Net (loss) income attributable to limited partners | $ (38,375) | $ 4,909 | $ 3,235 | $ 3,114 |
| **(Loss) earnings per limited partner unit:** | | | | |
| Common unit – basic | $ (0.65) | $ 0.08 | $ 0.05 | $ 0.08 |
| Common unit – diluted | $ (0.65) | $ 0.08 | $ 0.05 | $ 0.08 |
| Subordinated unit – basic and diluted | $ (0.65) | $ 0.08 | $ 0.05 | $ 0.02 |

(1) Retrospectively adjusted for the impact of the 2016 Drop Down, the Polar and Divide Drop Down and the reclassification of certain revenues for Bison Midstream.
(2) In the quarter ended December 31, 2014, net loss attributable to SMLP includes $54.2 million of goodwill impairment and $5.5 million of long-lived asset impairment.

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

| | Quarter ended September 30, 2015 | Quarter ended June 30, 2015 | Quarter ended March 31, 2015 |
|---|---|---|---|
| | | (In thousands) | |
| Total revenues as originally reported | $ 103,249 | $ 77,274 | $ 68,579 |
| 2016 Drop Down | 8,644 | 5,911 | 4,870 |
| Bison revenue reclass | 3,308 | 3,670 | 4,056 |
| Polar and Divide Drop Down | — | — | 8,582 |
| Total revenues | $ 115,201 | $ 86,855 | $ 86,087 |

| | Quarter ended September 30, 2014 | Quarter ended June 30, 2014 | Quarter ended March 31, 2014 |
|---|---|---|---|
| | | (In thousands) | |
| Total revenues as originally reported | $ 79,030 | $ 80,796 | $ 76,202 |
| 2016 Drop Down | 4,108 | 2,414 | 1,922 |
| Bison revenue reclass | 5,260 | 4,665 | 4,399 |
| Polar and Divide Drop Down | 5,754 | 5,188 | 3,179 |
| Total revenues | $ 94,152 | $ 93,063 | $ 85,702 |