Summit Midstream Partners, LP
Form 10-Q
November 09, 2015
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-Q
(Mark One)
[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2015
or
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission file number: 001-35666
Summit Midstream Partners, LP
(Exact name of registrant as specified in its charter)

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. x Yes o No
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
x Yes o No
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). o Yes x No
Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	As of October 31, 2015
Common Units	42,062,644 units

Subordinated Units	24,409,850 units
General Partner Units	1,354,700 units

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FORWARD-LOOKING STATEMENTS

Investors are cautioned that certain statements contained in this report as well as in periodic press releases and certain oral statements made by our officials during our presentations are “forward-looking” statements. Forward-looking statements include, without limitation, any statement that may project, indicate or imply future results, events, performance or achievements, and may contain the words “expect,” “intend,” “plan,” “anticipate,” “estimate,” “believe,” “will “will continue,” “will likely result,” and similar expressions, or future conditional verbs such as “may,” “will,” “should,” “wou and “could.” In addition, any statement concerning future financial performance (including future revenues, earnings or growth rates), ongoing business strategies or prospects, and possible actions taken by us or our affiliates, are also forward-looking statements. Without limiting the generality of the foregoing, forward-looking statements contained in this report specifically include statements and the discussion of the evaluation of strategic options in the section entitled "Trends and Outlook—Acquisitions from Summit Investments and Third Parties" included in Management's Discussion and Analysis of Financial Condition and Results of Operations herein. These forward-looking statements involve external risks and uncertainties, including, but not limited to, those described in the section entitled "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, natural gas liquids ("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;
- our ability to acquire any assets owned by Summit Midstream Partners, LLC ("Summit Investments"), which is subject to a number of factors, including Summit Investments deciding, in its sole discretion, to offer us the right to acquire such assets, the ability to reach agreement on acceptable terms, the approval of the conflicts committee of our general partner's board of directors (if appropriate), 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;

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- 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.

Further, we are subject to the risks and uncertainties of any strategic option, including whether any strategic options will be identified and, if identified, whether it will be pursued and consummated. 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.

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PART I—FINANCIAL INFORMATION
Item 1. Financial Statements.
SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
UNAUDITED CONDENSED CONSOLIDATED BALANCE SHEETS

	September 30, 2015	December 31, 2014
	(In thousands)	
Assets		
Current assets:		
Cash and cash equivalents	$5,459	$26,504
Accounts receivable	45,902	89,201
Other current assets	3,773	3,517
Total current assets	55,134	119,222
Property, plant and equipment, net	1,448,548	1,414,350
Intangible assets, net	448,293	477,734
Goodwill	265,062	265,062
Other noncurrent assets	15,145	17,353
Total assets	$2,232,182	$2,293,721
Liabilities and Partners' Capital		
Current liabilities:		
Trade accounts payable	$15,560	$24,855
Due to affiliate	625	2,711
Deferred revenue	677	2,377
Ad valorem taxes payable	7,318	9,118
Accrued interest	7,733	18,858
Other current liabilities	12,014	13,550
Total current liabilities	43,927	71,469
Long-term debt	904,642	808,000
Deferred revenue	32,333	55,239
Other noncurrent liabilities	6,597	7,292
Total liabilities	987,499	942,000
Commitments and contingencies		
Common limited partner capital (42,063 units issued and outstanding at September 30, 2015 and 34,427 units issued and outstanding at December 31, 2014)	906,107	649,060
Subordinated limited partner capital (24,410 units issued and outstanding at September 30, 2015 and December 31, 2014)	307,719	293,153
General partner interests (1,355 units issued and outstanding at September 30, 2015 and 1,201 units issued and outstanding at December 31, 2014)	30,857	24,676
Summit Investments' equity in contributed subsidiaries	—	384,832
Total partners' capital	1,244,683	1,351,721
Total liabilities and partners' capital	$2,232,182	$2,293,721

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

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SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
	(In thousands, except per-unit amounts)			
Revenues:				
Gathering services and related fees	$90,685	$56,598	$212,822	$162,359
Natural gas, NGLs and condensate sales	8,710	23,970	33,290	76,977
Other revenues	3,854	4,216	11,572	10,813
Total revenues	103,249	84,784	257,684	250,149
Costs and expenses:				
Cost of natural gas and NGLs	3,652	12,842	13,941	42,315
Operation and maintenance	23,045	21,840	65,718	66,468
General and administrative	8,714	9,414	27,746	28,127
Transaction costs	119	62	714	675
Depreciation and amortization	24,112	22,204	71,845	64,018
(Gain) loss on asset sales, net	—	—	(214)	6
Long-lived asset impairment	7,696	—	7,696	—
Total costs and expenses	67,338	66,362	187,446	201,609
Other income	1	1	2	3
Interest expense	(12,132)	(10,558)	(36,333)	(28,504)
Income before income taxes	23,780	7,865	33,907	20,039
Income tax expense	(176)	(28)	(248)	(655)
Net income	$23,604	$7,837	$33,659	$19,384
Less net income attributable to Summit Investments	—	1,724	5,403	5,690
Net income attributable to SMLP	23,604	6,113	28,256	13,694
Less net income attributable to general partner, including IDRs	2,408	1,204	5,866	2,436
Net income attributable to limited partners	$21,196	$4,909	$22,390	$11,258
Earnings per limited partner unit:				
Common unit – basic	$0.32	$0.08	$0.33	$0.22
Common unit – diluted	$0.32	$0.08	$0.33	$0.22
Subordinated unit – basic and diluted	$0.32	$0.08	$0.40	$0.17
Weighted-average limited partner units outstanding:				
Common units – basic	41,974	34,424	38,258	32,936
Common units – diluted	42,147	34,658	38,387	33,144
Subordinated units – basic and diluted	24,410	24,410	24,410	24,410
Cash distributions declared and paid per common unit	$0.570	$0.520	$1.695	$1.500

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

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

	Partners' capital Limited partners Common	Subordinated	General partner	Summit Investments' equity in contributed subsidiaries	Total
	(In thousands)				
Partners' capital, January 1, 2014	$566,532	$379,287	$23,324	$523,944	$1,493,087
Net income	6,506	4,752	2,436	5,690	19,384
Distributions to unitholders	(49,069)	(36,615)	(3,018)	—	(88,702)
Unit-based compensation	3,499	—	—	—	3,499
Tax withholdings on vested SMLP LTIP awards	(656)	—	—	—	(656)
Issuance of common units, net of offering costs	197,879	—	—	—	197,879
Contribution from general partner	—	—	4,235	—	4,235
Purchase of Red Rock Gathering	—	—	—	(305,000)	(305,000)
Excess of consideration paid over acquired carrying value of Red Rock Gathering	(36,228)	(25,691)	(1,264)	63,183	—
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	—	—	—	44,116	44,116
Expenses paid by Summit Investments on behalf of contributed subsidiaries	—	—	—	8,858	8,858
Capitalized interest allocated from Summit Investments to contributed subsidiaries	—	—	—	529	529
Capital expenditures paid by Summit Investments on behalf of contributed subsidiaries	—	—	—	387	387
Class B membership interest unit-based compensation	—	—	—	255	255
Repurchase of SMLP LTIP units	(228)	—	—	—	(228)
Partners' capital, September 30, 2014	$690,661	$323,455	$25,798	$341,962	$1,381,876

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

	Partners' capital Limited partners Common	Subordinated	General partner	Summit Investments' equity in contributed subsidiaries	Total
	(In thousands)				
Partners' capital, January 1, 2015	$649,060	$293,153	$24,676	$384,832	$1,351,721
Net income	14,129	8,261	5,866	5,403	33,659
Distributions to unitholders	(62,694)	(41,376)	(7,029)	—	(111,099)
Unit-based compensation	4,954	—	—	—	4,954
Tax withholdings on vested SMLP LTIP awards	(1,435)	—	—	—	(1,435)
Issuance of common units, net of offering costs	222,014	—	—	—	222,014
Contribution from general partner	—	—	4,737	—	4,737
Purchase of Polar and Divide	—	—	—	(285,677)	(285,677)
Excess of acquired carrying value over consideration paid for Polar and Divide	80,079	47,681	2,607	(130,367)	—
Cash advance from Summit Investments to contributed subsidiaries, net	—	—	—	21,719	21,719
Expenses paid by Summit Investments on behalf of contributed subsidiaries	—	—	—	3,084	3,084
Capitalized interest allocated from Summit Investments to contributed subsidiaries	—	—	—	921	921
Class B membership interest unit-based compensation	—	—	—	85	85
Partners' capital, September 30, 2015	$906,107	$307,719	$30,857	$—	$1,244,683

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

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

	Nine months ended September 30,	
	2015	2014
	(In thousands)	
Cash flows from operating activities:		
Net income	$33,659	$19,384
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	72,493	64,711
Amortization of deferred loan costs	2,412	1,970
Unit-based compensation	5,039	3,754
(Gain) loss on asset sales, net	(214)	6
Long-lived asset impairment	7,696	—
Changes in operating assets and liabilities:		
Accounts receivable	43,299	17,894
Trade accounts payable	(3,537)	(2,259)
Due to affiliate	853	(228)
Change in deferred revenue	(24,606)	12,505
Ad valorem taxes payable	(1,800)	(1,435)
Accrued interest	(11,125)	(3,036)
Other, net	(2,280)	1,787
Net cash provided by operating activities	121,889	115,053
Cash flows from investing activities:		
Capital expenditures	(89,290)	(154,705)
Proceeds from asset sales	238	24
Acquisition of gathering systems	—	(10,872)
Acquisitions of gathering systems from affiliate	(288,618)	(305,000)
Net cash used in investing activities	(377,670)	(470,553)

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

	Nine months ended September 30,	
	2015	2014
	(In thousands)	
Cash flows from financing activities:		
Distributions to unitholders	(111,099)	(88,702)
Borrowings under revolving credit facility	147,000	204,295
Repayments under revolving credit facility	(51,000)	(315,295)
Deferred loan costs	(154)	(5,226)
Proceeds from issuance of common units, net	222,014	197,879
Contribution from general partner	4,737	4,235
Cash advance from Summit Investments to contributed subsidiaries, net	21,719	44,116
Expenses paid by Summit Investments on behalf of contributed subsidiaries	3,084	8,858
Issuance of senior notes	—	300,000
Other, net	(1,565)	(884)
Net cash provided by financing activities	234,736	349,276
Net change in cash and cash equivalents	(21,045)	(6,224)
Cash and cash equivalents, beginning of period	26,504	20,357
Cash and cash equivalents, end of period	$5,459	$14,133
Supplemental cash flow disclosures:		
Cash interest paid	$46,434	$29,779
Less capitalized interest	2,307	3,014
Interest paid (net of capitalized interest)	$44,127	$26,765
Noncash investing and financing activities:		
Capital expenditures in trade accounts payable (period-end accruals)	$12,319	$30,886
Capital leases	1,021	—
Excess of acquired carrying value over consideration paid for Polar and Divide	130,367	—
Capitalized interest allocated to contributed subsidiaries from Summit Investments	921	529
Capital expenditures paid by Summit Investments on behalf of contributed subsidiaries	—	387
Excess of consideration paid over acquired carrying value of Red Rock Gathering	—	(63,183)
Assets contributed to Red Rock Gathering from Summit Investments	—	4,233

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

SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
1. ORGANIZATION, BUSINESS OPERATIONS AND PRESENTATION AND CONSOLIDATION

Organization. Summit Midstream Partners, LP ("SMLP" or the "Partnership"), a Delaware limited partnership, is a growth-oriented limited partnership focused on developing, owning and operating midstream energy infrastructure assets that are strategically located in the core producing areas of unconventional resource basins, primarily shale formations, in North America.

SMLP and its subsidiaries are managed and operated by the board of directors and executive officers of Summit Midstream GP, LLC (the "general partner"). Summit Investments, as the ultimate owner of our general partner, controls us and has the right to appoint the entire board of directors of our general partner, including our independent directors. 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.

As of September 30, 2015, Summit Midstream Partners Holdings, LLC ("SMP Holdings"), a wholly owned subsidiary of Summit Investments, held 5,293,571 SMLP common units, all of our subordinated units and all of our general partner units and incentive distribution rights ("IDRs").

On May 18, 2015, the Partnership acquired certain crude oil and produced water gathering systems and crude oil transmission pipelines (under development) held by Polar Midstream, LLC ("Polar Midstream") and Epping Transmission Company, LLC ("Epping") located in the Williston Basin (collectively "Polar and Divide") from SMP Holdings (the "Polar and Divide Drop Down"). Because the Polar and Divide system was acquired from SMP Holdings, it was deemed a transaction among entities under common control. Common control began in (i) February 2013 for Polar Midstream and (ii) April 2014 for Epping.

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

- the Mountaineer Midstream system ("Mountaineer Midstream"), a natural gas gathering system located in the Appalachian Basin, which includes the Marcellus Shale formation in northern West Virginia;
- Bison Midstream, LLC ("Bison Midstream"), an associated natural gas gathering system located in the Williston Basin, which includes the Bakken and Three Forks shale formations in northwestern North Dakota;
- Polar and Divide, a crude oil and produced water gathering system and transmission pipelines (under development) located in the Williston Basin, which includes the Bakken and Three Forks shale formations in northwestern North Dakota;
- DFW Midstream Services LLC ("DFW Midstream"), a natural gas gathering system located in the Fort Worth Basin, which includes the Barnett Shale formation in north-central Texas; and
- Grand River Gathering, LLC ("Grand River Gathering"), 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.

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

Presentation and Consolidation. We prepare our unaudited condensed 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"). The unaudited condensed consolidated financial statements include the assets, liabilities, and results of operations of SMLP and its subsidiaries. All intercompany transactions among the consolidated entities have been eliminated in consolidation.

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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.

These unaudited condensed consolidated financial statements have been prepared pursuant to the rules and the regulations of the Securities and Exchange Commission (the "SEC"). Certain information and note disclosures normally included in annual financial statements prepared in accordance with GAAP have been condensed or omitted pursuant to those rules and regulations. We believe that the disclosures made are adequate to make the information not misleading. In the opinion of management, the unaudited condensed consolidated financial statements contain all adjustments, including normal recurring accruals, which are necessary to fairly present the unaudited condensed consolidated balance sheet as of September 30, 2015, the unaudited condensed consolidated statements of operations for the three- and nine-month periods ended September 30, 2015 and 2014, and the unaudited condensed consolidated statements of partners' capital and cash flows for the nine-month periods ended September 30, 2015 and 2014. These unaudited condensed consolidated financial statements should be read in conjunction with the consolidated financial statements and notes thereto that are included in our annual report on Form 10-K for the year ended December 31, 2014 as filed with the SEC on March 2, 2015, and as updated and superseded by our current report on Form 8-K dated September 11, 2015 (the "2014 Annual Report"). The results of operations for an interim period are not necessarily indicative of results expected for a full year.

SMLP recognized its acquisitions of (i) Polar Midstream and Epping and (ii) Red Rock Gathering (the "Red Rock Drop Down") at Summit Investments' historical cost because the acquisitions were executed by entities under common control. The excess of Summit Investments' net investment in Polar Midstream and Epping was recognized as an addition to partners' capital. The excess of the purchase price paid by SMLP over Summit Investments' net investment in Red Rock Gathering was recognized as a reduction to partners' capital. Due to the common control aspect, the Polar and Divide Drop Down and the Red Rock Drop Down were accounted for by the Partnership on an “as-if pooled” basis for the periods during which common control existed. For the purposes of these unaudited condensed consolidated financial statements, SMLP's results of operations reflect the results of operations of Polar Midstream, Epping and Red Rock Gathering for all periods presented.

Reclassifications. Certain reclassifications have been made to prior-year amounts to conform to current-year presentation. In the third quarter of 2015, 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.

In the second quarter of 2015, we evaluated our classification of revenues and concluded that creating an “other revenues” category would provide reporting that was more reflective of our results of operations and how we manage our business. As such, certain revenue transactions that represented the “and other” portions of (i) gathering services and (ii) natural gas, NGLs and condensate sales have been reclassified to other revenues. Other revenues also includes the amortization expense associated with our favorable and unfavorable gas gathering contracts. The amounts reclassified to other revenues for each period presented can be determined based on the total of the other revenues line item and the amount of amortization of favorable and unfavorable gas gathering contracts disclosed in Note 5. These reclassifications had no impact on total revenues, total costs and expenses, net income, total partners' capital or segment adjusted EBITDA.

Also in the second quarter or 2015, we evaluated our historical classification of electricity expense for Bison Midstream. In connection with the reclassification of certain revenues noted above and to be consistent with the classification of pass-through electricity expense for our other operating segments, we reclassified pass-through electricity expenses for Bison Midstream ($1.6 million for the three months ended September 30, 2014, and $2.7 million and $3.8 million for the nine months ended September 30, 2015 and 2014, respectively) from costs of natural gas and NGLs to operation and maintenance. These reclassifications had no impact on total revenues, total costs and expenses, net income, total partners' capital or segment adjusted EBITDA.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Property, Plant, and Equipment. We record property, plant, and equipment at historical cost of construction or fair value of the assets at acquisition. We capitalize expenditures that extend the useful life of an asset or enhance its productivity or efficiency from its original design over the expected remaining period of use. For maintenance and repairs that do not add capacity or extend the useful life of an asset, we recognize expenditures as an expense as incurred. We capitalize project costs incurred during construction, including interest on funds borrowed to finance the construction of facilities, as construction in progress. Prior to the Polar and Divide Drop Down and the Red Rock Drop Down, a subsidiary of Summit Investments incurred interest expense related to certain Polar and Divide and Red Rock Gathering capital projects. The associated interest expense was allocated to Polar and Divide and Red Rock Gathering as a noncash equity contribution and capitalized into the basis of the asset.

We base an asset's carrying value on estimates, assumptions and judgments for useful life and salvage value. We record depreciation on a straight-line basis over an asset's estimated useful life. We base our estimates for useful life on various factors including age (in the case of acquired assets), manufacturing specifications, technological advances, and historical data concerning useful lives of similar assets. Construction in progress is depreciated consistent with its applicable asset class once it is placed in service. Land and line fill are not depreciated.

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.

Capital Leases. Leased property and equipment meeting capital lease criteria are capitalized based on the present value of the minimum payments required at inception of the lease and are recognized in property, plant and equipment, net on the balance sheet. Obligations under capital leases are recognized in other current liabilities and long-term debt on the balance sheet. We record depreciation on a straight-line basis over the leased asset's estimated useful life.

Impairment of Long-Lived Assets. We test assets for impairment when events or circumstances indicate that the carrying value of a long-lived asset may not be recoverable. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from its use and eventual disposition. If we conclude that an asset's carrying value will not be recovered through future cash flows, we recognize an impairment loss on the long-lived asset equal to the amount by which the carrying value exceeds its fair value. We determine fair value using either a market-based approach or an income-based approach. We concluded that none of our long-lived assets had been impaired during the periods covered by this report, except as discussed in Notes 4 and 6.

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 and keep-whole arrangements. These revenues are recognized in natural gas, NGLs and condensate sales with corresponding expense recognition 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 Gathering. 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 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 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 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.

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

Environmental Matters. We are subject to various federal, state and local laws and regulations relating to the protection of the environment. 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.

Other Significant Accounting Policies. For information on our other significant accounting policies, see Note 2 of the consolidated financial statements included in the 2014 Annual Report.

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

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

In February 2015, the FASB issued ASU No. 2015-02—Consolidation (Topic 810): Amendments to the Consolidation Analysis ("ASU 2015-02"). The standard changes the analysis that a reporting entity must perform to

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determine whether it should consolidate certain types of legal entities. 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 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 will result in a reclassification from other noncurrent assets to long-term debt of the debt issuance costs associated with our senior notes. Debt issuance costs associated with our revolving credit facility will remain in other noncurrent assets (see Note 8). There will be no impact on interest expense, net income, earnings per unit or partners' capital.

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

3. SEGMENT INFORMATION

As of September 30, 2015, our reportable segments are:

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

Each of our reportable segments provides midstream services in a specific geographic area. Within specific geographic areas, we may further differentiate reportable segments by type of gathering service provided. Our reportable segments reflect the way in which we internally report the financial information used to make decisions and allocate resources in connection with our operations.

In the first quarter of 2015, we combined our Red Rock Gathering operating segment with the Grand River Gathering operating segment to become one operating segment serving the Piceance Basin. Prior to 2015, we aggregated the Red Rock Gathering and Grand River Gathering operating segments into the Piceance Basin reportable segment.

In the second quarter of 2015, in connection with the Polar and Divide Drop Down, we identified two reportable segments in the Williston Basin. We had previously only provided natural gas gathering services in the Williston Basin. With the acquisition of Polar and Divide, we now also provide crude oil and produced water gathering services in the Williston Basin. As such, we evaluated the quantitative and qualitative factors for operating segment aggregation in the Williston Basin and concluded that the characteristics for crude oil and produced water gathering services were not sufficiently similar to those of our natural gas gathering services. As a result, we now report the

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results of Bison Midstream in the Williston Basin – Gas reportable segment and those of Polar and Divide in the Williston Basin – Liquids reportable segment.

Corporate represents those 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.

	September 30, 2015	December 31, 2014
	(In thousands)	
Assets:		
Marcellus Shale	$236,322	$243,884
Williston Basin – Gas	283,884	311,041
Williston Basin – Liquids	448,761	398,847
Barnett Shale	419,421	428,935
Piceance Basin	826,895	872,437
Total reportable segment assets	2,215,283	2,255,144
Corporate	16,899	38,577
Total assets	$2,232,182	$2,293,721

Revenues by reportable segment follow.

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
	(In thousands)			
Revenues:				
Marcellus Shale	$6,963	$5,674	$22,585	$16,695
Williston Basin – Gas	6,390	15,965	22,754	47,547
Williston Basin – Liquids	9,563	5,754	28,050	14,121
Barnett Shale	19,788	22,737	67,508	70,015
Piceance Basin	60,545	34,654	116,787	101,771
Total reportable segment revenues and total revenues	$103,249	$84,784	$257,684	$250,149

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

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
Percentage of total revenues (1):				
Counterparty A - Piceance	38 %	*	19 %	*
Counterparty B - Piceance	*	17 %	12 %	17 %
Counterparty C - Williston Basin – Gas	*	11 %	*	10 %

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

* Less than 10%

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

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
	(In thousands)			
Depreciation and amortization:				
Marcellus Shale	$2,170	$1,853	$6,508	$5,515
Williston Basin – Gas	4,830	4,690	14,306	13,428
Williston Basin – Liquids	1,839	1,168	5,186	2,860
Barnett Shale	4,081	3,968	12,352	11,795
Piceance Basin	11,239	10,626	33,653	30,687
Total reportable segment depreciation and amortization	24,159	22,305	72,005	64,285
Corporate	138	142	488	426
Total depreciation and amortization	$24,297	$22,447	$72,493	$64,711

Capital expenditures by reportable segment follow.

	Nine months ended September 30,	
	2015	2014
	(In thousands)	
Capital expenditures:		
Marcellus Shale	$1,238	$29,770
Williston Basin – Gas	4,320	37,041
Williston Basin – Liquids	64,053	50,559
Barnett Shale	4,909	13,015
Piceance Basin	14,343	24,084
Total reportable segment capital expenditures	88,863	154,469
Corporate	427	236
Total capital expenditures	$89,290	$154,705

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

Segment adjusted EBITDA by reportable segment follows.

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
	(In thousands)			
Reportable segment adjusted EBITDA:				
Marcellus Shale	$5,795	$3,956	$18,492	$11,676
Williston Basin – Gas	5,100	5,114	15,174	14,597
Williston Basin – Liquids	5,719	2,977	17,262	5,977
Barnett Shale	13,143	15,617	45,444	45,609
Piceance Basin	24,328	28,138	78,427	80,499
Total reportable segment adjusted EBITDA	$54,085	$55,802	$174,799	$158,358

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

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
	(In thousands)			
Reconciliation of Income Before Income Taxes to Segment Adjusted EBITDA:				
Income before income taxes	$23,780	$7,865	$33,907	$20,039
Add:				
Allocated corporate expenses	5,630	2,553	17,633	7,537
Interest expense	12,132	10,558	36,333	28,504
Depreciation and amortization	24,297	22,447	72,493	64,711
Adjustments related to MVC shortfall payments	(21,354)	11,220	1,914	33,810
Unit-based compensation	1,905	1,160	5,039	3,754
Loss on asset sales	—	—	—	6
Long-lived asset impairment	7,696	—	7,696	—
Less:				
Interest income	1	1	2	3
Gain on asset sales	—	—	214	—
Total reportable segment adjusted EBITDA	$54,085	$55,802	$174,799	$158,358

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.

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
	(In thousands)			
Adjustments related to MVC shortfall payments:				
Williston Basin – Gas	$3,470	$2,744	$8,970	$8,069
Barnett Shale	86	246	(1,915)	404
Piceance Basin	(24,910)	8,230	(5,141)	25,337
Total adjustments related to MVC shortfall payments	$(21,354)	$11,220	$1,914	$33,810

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4. PROPERTY, PLANT, AND EQUIPMENT, NET

Details on property, plant, and equipment, including leased property and equipment meeting capital lease criteria, follow.

	Useful lives (In years)	September 30, 2015	December 31, 2014
		(Dollars in thousands)	
Gathering and processing systems and related equipment	30	$1,514,729	$1,459,585
Construction in progress	n/a	55,853	37,604
Land and line fill	n/a	10,457	9,964
Other	4-15	30,659	28,871
Total		1,611,698	1,536,024
Less accumulated depreciation		163,150	121,674
Property, plant, and equipment, net		$1,448,548	$1,414,350

During the third quarter of 2015, we reviewed certain property, plant and equipment balances that had been identified as potentially impaired. In connection therewith, we estimated the fair value of the identified property, plant and equipment using a market-based approach and wrote off approximately $7.7 million of costs associated with projects that had been terminated. The net impact of this action is reflected in long-lived asset impairment on the statement of operations. Of the total impairment, $6.7 million related to the Williston Basin – Gas reportable segment and $1.0 million related to the Williston Basin – Liquids reportable segment. Our impairment determinations, in the context of our third quarter 2015 review, 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.

Depreciation expense, including amounts related to capital lease arrangements, and capitalized interest follow.

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
	(In thousands)			
Depreciation expense	$13,987	$12,756	$41,476	$35,955
Capitalized interest	656	1,180	2,307	3,014

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.

	September 30, 2015			
	Useful lives (In years)	Gross carrying amount	Accumulated amortization	Net
	(Dollars in thousands)			
Favorable gas gathering contracts	18.7	$24,195	$(9,208)	$14,987
Contract intangibles	12.5	426,464	(102,217)	324,247
Rights-of-way	24.3	125,661	(16,602)	109,059
Total intangible assets		$576,320	$(128,027)	$448,293
Unfavorable gas gathering contract	10.0	$10,962	$(5,889)	$5,073

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

We recognized amortization expense in other revenues as follows:

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
	(In thousands)			
Amortization expense – favorable gas gathering contracts	$(351)	$(436)	$(1,152)	$(1,305)
Amortization expense – unfavorable gas gathering contract	166	193	504	612

We recognized amortization expense in costs and expenses as follows:

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
	(In thousands)			
Amortization expense – contract intangibles	$8,835	$8,198	$26,504	$24,357
Amortization expense – rights-of-way	1,294	1,251	3,865	3,708

The estimated aggregate annual amortization expected to be recognized for the remainder of 2015 and each of the four succeeding fiscal years follows.

	Intangible assets	Unfavorable gas gathering contract
	(In thousands)	
2015	$10,555	$187
2016	42,293	924
2017	41,143	1,047
2018	40,597	1,035
2019	40,842	1,045

6. GOODWILL

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 value, including goodwill. We test goodwill for impairment using a two-step quantitative test. In the first step, we compare the fair value of the reporting unit to its carrying value, including goodwill. If the reporting unit’s fair value exceeds its carrying value, including goodwill, 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, including goodwill, exceeds its fair value, we proceed to step two. In step two, we compare the carrying value of the reporting unit, including goodwill, to its implied fair value. If we determine that the carrying value of a reporting unit, including goodwill, exceeds its implied fair value, we recognize the excess of the carrying value over the implied fair value as a goodwill impairment loss.

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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 Gathering, Mountaineer Midstream and Polar Midstream reporting units substantially exceeded their carrying value, including goodwill. Because the fair values of all three reporting units exceeded their carrying values, including goodwill, there have been no impairments of goodwill in connection with our 2015 annual goodwill impairment test.

Bison Midstream Fourth Quarter 2014 Goodwill Impairment. 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.

7. DEFERRED REVENUE

A rollforward of current deferred revenue follows.

	Williston Basin - Gas	Barnett Shale	Piceance Basin	Total current
	(In thousands)			
Current deferred revenue, January 1, 2015	$—	$2,377	$—	$2,377
Additions	—	999	—	999
Less revenue recognized	—	2,699	—	2,699
Current deferred revenue, September 30, 2015	$—	$677	$—	$677

A rollforward of noncurrent deferred revenue follows.

	Williston Basin - Gas	Barnett Shale	Piceance Basin	Total noncurrent
	(In thousands)			
Noncurrent deferred revenue, January 1, 2015	$17,132	$—	$38,107	$55,239
Additions	—	—	11,509	11,509
Less revenue recognized	27	—	34,388	34,415
Noncurrent deferred revenue, September 30, 2015	$17,105	$—	$15,228	$32,333

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

As of September 30, 2015, accounts receivable included $0.8 million of shortfall billings related to MVC arrangements that can be utilized to offset gathering fees in subsequent periods.

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8. LONG-TERM DEBT

Long-term debt, including the long-term portion of amounts related to capital lease arrangements, consisted of the following:

	September 30, 2015	December 31, 2014
	(In thousands)	
Variable rate senior secured revolving credit facility (2.45% at September 30, 2015 and 2.67% at December 31, 2014) due November 2018	$304,000	$208,000
5.50% Senior unsecured notes due August 2022	300,000	300,000
7.50% Senior unsecured notes due July 2021	300,000	300,000
Capital leases, long-term portion	642	—
Total long-term debt	$904,642	$808,000

Revolving Credit Facility. We have a senior secured revolving credit facility which allows for revolving loans, letters of credit and swingline loans (the "revolving credit facility"). The revolving credit facility has a $700.0 million borrowing capacity, matures in November 2018, and includes a $200.0 million accordion feature. It is secured by the membership interests of Summit Holdings and those of its subsidiaries. Substantially all of 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 September 30, 2015, we were in compliance with the revolving credit facility's covenants. There were no defaults or events of default during the nine months ended September 30, 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 their subsidiaries by dividend or loan.

As of September 30, 2015, we were in compliance with the covenants of the 5.5% senior notes and the 7.5% senior notes. There were no defaults or events of default during the nine months ended September 30, 2015.

9. FINANCIAL INSTRUMENTS

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

Accounts receivable primarily comprise amounts due for the gathering, treating and processing services we provide to our customers and also the sale of natural gas liquids resulting from our processing services. This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers may be similarly affected by changes in economic, industry or other conditions. We monitor the creditworthiness of our counterparties and can require letters of credit for receivables from counterparties that are judged to have substandard credit, unless the credit risk can otherwise be mitigated. Our top five customers or counterparties accounted for 59% of total accounts receivable at September 30, 2015, compared with 62% as of December 31, 2014.

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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.

	September 30, 2015		December 31, 2014	
	Carrying value	Estimated fair value (Level 2)	Carrying value	Estimated fair value (Level 2)
	(In thousands)			
Revolving credit facility	$304,000	$304,000	$208,000	$208,000
5.5% Senior notes	300,000	260,500	300,000	281,750
7.5% Senior notes	300,000	289,875	300,000	306,750

The revolving credit facility's carrying value on the balance sheet is its fair value due to its floating interest rate. The fair value for the senior notes is based on an average of nonbinding broker quotes as of September 30, 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.
Nonfinancial assets and liabilities initially measured at fair value include those acquired and assumed in connection with third-party business combinations.

10. PARTNERS' CAPITAL

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

	Common	Subordinated	General partner	Total
Units, January 1, 2015	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, September 30, 2015	42,062,644	24,409,850	1,354,700	67,827,194

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

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

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

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

Cash Distributions. Details of cash distributions declared in 2015 follow.

Attributable to the quarter ended	Payment date	Per-unit distribution	Cash paid to common unitholders	Cash paid to subordinated unitholders	Cash paid to general partner	Cash paid for IDRs	Total distribution
		(In thousands, except per-unit amounts)					
December 31, 2014	February 13, 2015	$0.5600	$19,279	$13,670	$702	$1,442	$35,093
March 31, 2015	May 15, 2015	$0.5650	$19,490	$13,792	$710	$1,534	$35,526
June 30, 2015	August 14, 2015	$0.5700	$23,925	$13,914	$810	$1,831	$40,480

On October 22, 2015, the board of directors of our general partner declared a distribution of $0.575 per unit attributable to the quarter ended September 30, 2015. The distribution will be paid on November 13, 2015 to unitholders of record at the close of business on November 6, 2015.

Summit Investments' Equity in Contributed Subsidiaries. Summit Investments' equity in contributed subsidiaries represents its position in the net assets of Polar and Divide and Red Rock Gathering that have been acquired by SMLP. The balance also reflects net income attributable to Summit Investments for Polar and Divide and Red Rock Gathering for the periods beginning on their respective acquisition dates by Summit Investments and ending on the dates they were acquired by the Partnership. For the three and nine months ended September 30, 2015 and 2014, net income was attributed to Summit Investments for (i) Polar and Divide for the period from January 1, 2015 to May 18, 2015 as well as the three and nine months ended September 30, 2014 and (ii) Red Rock Gathering for the period from January 1, 2014 to March 18, 2014. Although included in partners' capital, these net income amounts have been excluded from the calculation of earnings per unit ("EPU").

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11. EARNINGS PER UNIT

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

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
	(In thousands, except per-unit amounts)			
Numerator for basic and diluted EPU:				
Allocation of net income among limited partner interests:				
Net income attributable to common units	$13,412	$2,874	$12,729	$7,167
Net income attributable to subordinated units	7,784	2,035	9,661	4,091
Net income attributable to limited partners	$21,196	$4,909	$22,390	$11,258
Denominator for basic and diluted EPU:				
Weighted-average common units outstanding – basic	41,974	34,424	38,258	32,936
Effect of nonvested phantom units	173	234	129	208
Weighted-average common units outstanding – diluted	42,147	34,658	38,387	33,144
Weighted-average subordinated units outstanding – basic and diluted	24,410	24,410	24,410	24,410
Earnings per limited partner unit:				
Common unit – basic	$0.32	$0.08	$0.33	$0.22
Common unit – diluted	$0.32	$0.08	$0.33	$0.22
Subordinated unit – basic and diluted	$0.32	$0.08	$0.40	$0.17

We excluded 63,261 units in our calculation of the effect of nonvested phantom units for the nine months ended September 30, 2015 because they were anti-dilutive. There were no anti-dilutive units during the three months ended September 30, 2015 or during the three and nine months ended September 30, 2014.

12. UNIT-BASED COMPENSATION

SMLP Long-Term Incentive Plan. The SMLP Long-Term Incentive Plan (the "SMLP LTIP") provides for equity awards to eligible officers, employees, consultants and directors of our general partner and its affiliates. Items to note are:

- In March 2015, we granted 200,283 phantom units to employees in connection with our annual incentive compensation award cycle. These awards had a grant date fair value of $33.94 and vest ratably over a three-year period.
- In September 2015 106,750 phantom units granted in connection with our initial public offering vested.
- As of September 30, 2015, approximately 4.4 million common units remained available for future issuance.

13. RELATED-PARTY 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.

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

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
	(In thousands)			
Operation and maintenance expense	$5,151	$5,050	$16,519	$14,620
General and administrative expense	5,013	5,512	16,299	17,152

Expenses Incurred by Summit Investments. Prior to the Polar and Divide Drop Down and the Red Rock 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 and
- 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.

14. COMMITMENTS AND CONTINGENCIES

Operating Leases. Rent expense related to operating leases, including rent expense incurred on our behalf and allocated to us by Summit Investments, was as follows:

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
	(In thousands)			
Rent expense	$519	$500	$1,501	$1,349

Environmental Matters. There are no material liabilities related to environmental remediation costs, arising from claims, assessments, litigation, fines, or penalties and other sources in the accompanying financial statements at September 30, 2015 or December 31, 2014. However, we can provide no assurance that significant costs and liabilities will not be incurred in the future. We are currently not aware of any material contingent liabilities that exist with respect to environmental matters.

Legal Proceedings. The Partnership is involved in various litigation and administrative proceedings arising in the normal course of business. Members of our senior legal and financial management teams review litigation on a quarterly and annual basis. 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 its financial position or results of operations.

15. ACQUISITIONS AND DROP DOWN TRANSACTIONS

Polar and Divide Drop Down. On May 18, 2015, we acquired Polar Midstream and Epping from a subsidiary of Summit Investments, subject to customary working capital and capital expenditures adjustments. Due to the concurrent timing of acquiring Polar Midstream and Epping, we have aggregated these purchases into the Polar and Divide Drop Down. We funded the initial combined purchase price of $290.0 million with (i) $92.5 million of borrowings under our 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.

Red Rock Drop Down. On March 18, 2014, we acquired Red Rock Gathering from a subsidiary of Summit Investments, subject to customary working capital adjustments. 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.

Supplemental Disclosures – As-If Pooled Basis. As a result of accounting for our drop down transactions similar to a pooling of interests, our historical financial statements and those of Polar Midstream, Epping and Red Rock

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Gathering 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.

	Three months ended September 30, 2014	Nine months ended September 30,	
		2015	2014
	(In thousands)		
SMLP revenues	$79,030	$244,411	$224,715
Polar and Divide revenues	5,754	13,273	14,121
Red Rock Gathering revenues (1)			11,313
Combined revenues	$84,784	$257,684	$250,149
SMLP net income	$6,113	$28,256	$13,694
Polar and Divide net income	1,724	5,403	2,862
Red Rock Gathering net income (1)			2,828
Combined net income	$7,837	$33,659	$19,384

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(1) Results are fully reflected in SMLP's revenues and net income subsequent to March 2014.

Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations.

This 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 for the period since December 31, 2014. As a result, the following discussion should be read in conjunction with the unaudited condensed consolidated financial statements and notes thereto included in this report and the MD&A and the audited consolidated financial statements and related notes that are included in the 2014 Annual Report. Among other things, those financial statements and the related notes include more detailed information regarding the basis of presentation for the following information. This discussion contains forward-looking statements that constitute our plans, estimates and beliefs. These forward-looking statements involve numerous risks and uncertainties, including, but not limited to, those discussed in Forward-Looking Statements on page ii of this quarterly report on Form 10-Q. Actual results may differ materially from those contained in any forward-looking statements.

MD&A comprises the following sections:

- Overview
- Trends and Outlook
- How We Evaluate Our Operations
- Results of Operations
- Non-GAAP Financial Measures
- Liquidity and Capital Resources
- Critical Accounting Estimates

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Overview

We are a growth-oriented limited partnership focused on developing, owning and operating midstream energy infrastructure assets that are strategically located in the core producing areas of unconventional resource basins, primarily shale formations, in North America. Our gathering systems and the unconventional resource basins in which they operate are as follows:

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

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

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 gathering and processing agreements with our customers and counterparties. 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 in the case of crude oil and to third-party disposal wells in the case of produced water.

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) our marketing of natural gas and natural gas liquids, (iii) the sale of physical natural gas purchased from our customers under percentage-of-proceeds and keep-whole arrangements, and (iv) from the sale of condensate retained from our gathering services at Grand River Gathering. We can be exposed to commodity price risk from engaging in any of these additional activities with the exception of 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 drilling and/or completion activities or temporarily shut-in production, which would reduce the volumes of natural gas and crude oil (and associated volumes of produced water) that we gather. If our customers delay drilling and/or completion activities or temporarily shut-in production, our MVCs ensure that we will receive a certain amount of revenue from our customers.

Most of our gas gathering agreements are underpinned by AMIs and MVCs. Our AMIs cover over 1.6 million acres in the aggregate and provide that any production from wells drilled by our customers within the AMI will be shipped on our gathering systems. Our MVCs, which totaled 3.7 trillion cubic feet equivalent ("Tcfe," determined using a ratio of six Mcf of natural gas to one barrel ("Bbl") of crude oil) at September 30, 2015 and average approximately 1.3 Bcfe/d through 2019 are designed to ensure that we will generate a certain amount of revenue from each customer over the life of the respective gathering agreement, whether by collecting gathering fees on actual throughput or from cash payments to cover any MVC shortfall. Our MVCs had a weighted-average remaining life of 8.7 years as of September 30, 2015, assuming minimum throughput volumes for the remainder of the term.

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Trends and Outlook

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

- Acquisitions from Summit Investments and third parties;
- Natural gas, NGL and crude oil supply and demand dynamics;
- Production from U.S. shale plays;
- Capital markets activity and cost of capital; and
- Shifts in operating costs and inflation.

Our expectations regarding any of the above trends 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. There have been no changes in key trends affecting our business, except as noted below.

Acquisitions from Summit Investments and Third Parties. As we noted in our 2014 Annual Report, our principal business strategy of increasing the cash distributions we make to unitholders depends, in part, on our ability to make accretive acquisitions of midstream assets from Summit Investments. We also disclosed, based on the size of Summit Investments' midstream asset portfolio and the expected additional investment that it would make to sufficiently develop those assets, that we estimated drop down transactions from Summit Investments or its subsidiaries in the range of $400.0 million to $800.0 million, annually through 2017. It was recently announced that our Sponsor, Energy Capital Partners, is exploring and evaluating strategic options to enhance the value of its investment in the Partnership and Summit Investments. As part of its review process, our Sponsor is evaluating whether it will augment the previously announced drop down plan by accelerating the overall drop down schedule or, in light of recent market conditions, adjusting the valuation metrics or financing plans to facilitate future drop down transactions. Our Sponsor is also exploring other strategic options, including, but not limited to:

- pursuing a sale or other divestiture of its ownership interest in Summit Investments, which could result in a change in control of SMLP;
- pursuing an initial public offering of interests in the general partner of SMLP; or
- other forms of sponsor support for SMLP in light of recent market volatility, such as a unit repurchase program that could involve open market purchases of SMLP common units in transactions to be executed from time to time as market conditions permit.

There can be no assurances that any such transaction or other course of action will be pursued or, if any such transaction is consummated, what a future owner of Summit Investments would do. The evaluation process is expected to be completed in the fourth quarter of 2015.

Natural Gas, NGL and Crude Oil Supply and Demand Dynamics. In connection with the Polar and Divide Drop Down, our exposure to crude oil supply and demand dynamics has increased.

For additional information, see the "Trends and Outlook" section of MD&A included in the 2014 Annual Report.

How We Evaluate Our Operations

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

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

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,

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

We review these metrics on a regular basis for consistency and trend analysis. There have been no changes in the composition or characteristics of these metrics during the nine months ended September 30, 2015, except as noted below.

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 natural gas is impacted by:

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

Following the Polar and Divide Drop Down, we will continue to report volumes for natural gas gathering and will now also report volumes for crude oil and produced water gathering. Crude oil and produced water gathering are aggregated and reported as "liquids" gathering and measured in thousands of barrels per day ("Mbbl/d"). Gathering rates are reported in barrels.

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 and keep-whole arrangements under which the gathering and processing revenues that we earn correlate directly with the fluctuating price of natural gas, condensate and NGLs.

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.

In the second quarter of 2015, we evaluated our classification of revenues and concluded that creating an “other revenues” category would provide reporting that was more reflective of our results of operations and how we manage our business. As such, certain revenue transactions that previously represented the “and other” portions of (i) gathering services and (ii) natural gas, NGLs and condensate sales have been reclassified to other revenues. Other revenues largely comprises electricity pass-throughs for customers of Bison Midstream and Grand River Gathering and connection fees on the Polar and Divide system. Other revenues also includes the amortization expense associated with our favorable and unfavorable gas gathering contracts. These reclassifications had no impact on total revenues, net income or total partners' capital.

Subsequent to the reclassification, revenues are recognized as follows:

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- Gathering services and related fees. Revenue earned from the natural gas gathering, treating and processing services that we provide to our natural gas and crude oil customers.
- Natural gas, NGLs and condensate sales. Revenue earned from (i) the sale of physical natural gas and natural gas liquids purchased from our customers under percentage-of-proceeds and keep-whole arrangements with certain of our customers on the Bison Midstream and Red Rock 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) electricity costs for which our Bison Midstream and Grand River Gathering customers have agreed to reimburse us and (ii) connection fees for customers of the Polar and Divide system.

For additional information on our reportable segments and how the other metrics noted above help us manage our business, see Note 3 to the unaudited condensed consolidated financial statements and the "How We Evaluate Our Operations" section of MD&A included in the 2014 Annual Report.

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Results of Operations

Consolidated Overview of the Three and Nine Months Ended September 30, 2015 and 2014

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

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
	(Dollars in thousands, except fee-rate data)			
Revenues:				
Gathering services and related fees	$90,685	$56,598	$212,822	$162,359
Natural gas, NGLs and condensate sales	8,710	23,970	33,290	76,977
Other revenues	3,854	4,216	11,572	10,813
Total revenues	103,249	84,784	257,684	250,149
Costs and expenses:				
Cost of natural gas and NGLs	3,652	12,842	13,941	42,315
Operation and maintenance	23,045	21,840	65,718	66,468
General and administrative	8,714	9,414	27,746	28,127
Transaction costs	119	62	714	675
Depreciation and amortization	24,112	22,204	71,845	64,018
(Gain) loss on asset sales, net	—	—	(214)	6
Long-lived asset impairment	7,696	—	7,696	—
Total costs and expenses	67,338	66,362	187,446	201,609
Other income	1	1	2	3
Interest expense	(12,132)	(10,558)	(36,333)	(28,504)
Income before income taxes	23,780	7,865	33,907	20,039
Income tax expense	(176)	(28)	(248)	(655)
Net income	$23,604	$7,837	$33,659	$19,384
Other Financial Data:				
EBITDA (1)	$60,208	$40,869	$142,731	$113,251
Adjusted EBITDA (1)	48,455	53,249	157,166	150,821
Capital expenditures	29,115	66,672	89,290	154,705
Acquisitions of gathering systems (2)	(4,323)	10,872	288,618	315,872
Distributable cash flow (1)	34,420	38,580	115,108	109,474
Operating Data:				
Aggregate average throughput – gas (MMcf/d)	1,390	1,465	1,497	1,393
Aggregate average throughput rate per Mcf – gas	$0.40	$0.42	$0.40	$0.43
Average throughput – liquids (Mbbl/d)	51.5	33.5	51.3	29.1
Average throughput rate per Bbl – liquids	$1.77	$1.69	$1.78	$1.59

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

(2) Reflects consideration paid, including working capital and capital expenditure adjustments paid (received), for acquisitions and/or drop downs. For additional information, see Note 15 to the unaudited condensed consolidated financial statements.

For additional information on how our financial results are recognized, see the "Results of Operations" section of MD&A included in the 2014 Annual Report.

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Volumes – Gas. For the three months ended September 30, 2015, our aggregate natural gas throughput volumes decreased to an average of 1,390 MMcf/d, compared with an average of 1,465 MMcf/d in the prior-year period. The decrease in natural gas volume throughput largely reflects volume throughput declines at Grand River Gathering and DFW Midstream, partially offset by an increase in volume throughput for Mountaineer Midstream.
For the nine months ended September 30, 2015, our aggregate natural gas throughput volumes increased to an average of 1,497 MMcf/d, compared with an average of 1,393 MMcf/d in the prior-year period. The increase in volume throughput largely reflects an increase in volume throughput for Mountaineer Midstream and DFW Midstream, partially offset by volume throughput declines on Grand River Gathering.
Volumes – Liquids. Average daily throughput for crude oil and produced water increased to 51.5 Mbbl/d for the three months ended September 30, 2015, compared with an average of 33.5 Mbbl/d in the prior-year period. For the nine months ended September 30, 2015, average daily throughput for crude oil and produced water increased to 51.3 Mbbl/d, compared with an average of 29.1 Mbbl/d in the prior-year period. The increase in crude oil and produced water volume throughput primarily reflects the continued development of the Polar and Divide system, new pad site connections and producers' ongoing drilling activity.
Revenues. For the three months ended September 30, 2015, total revenues increased $18.5 million, or 22%. The increase in total revenues primarily reflects (i) the recognition of $34.4 million of revenue that had been previously deferred in connection with MVC shortfall payments received from a Grand River Gathering customer (see Note 7 to the unaudited condensed consolidate financial statements) and (ii) an increase in gathering services and related fees for Polar Midstream. These increases were partially offset by a decline in natural gas, NGLs and condensate sales for Bison Midstream, Grand River Gathering and DFW Midstream.
For the nine months ended September 30, 2015, total revenues increased $7.5 million, or 3%. The increase in total revenues reflects the previously mentioned deferred revenue release and an increase in gathering services and related fees across all gathering systems, except Grand River Gathering (net of the deferred revenue release). These increases were largely offset by a decline in natural gas, NGLs and condensate sales for Bison Midstream, Grand River Gathering and DFW Midstream.
Gathering Services and Related Fees. The increase in gathering services and related fees during the three months ended September 30, 2015 was primarily driven by the recognition of deferred revenue noted above and higher volume throughput on the Polar and Divide and Mountaineer Midstream systems, partially offset by lower volumes at Grand River Gathering. The aggregate average throughput rate for natural gas decreased to $0.40/Mcf during the three months ended September 30, 2015, compared with $0.42/Mcf in the prior-year period primarily as a result of a larger proportion of gathering fee revenue from Mountaineer Midstream. The aggregate average throughput rate for crude oil and produced water increased to $1.77/Bbl during the three months ended September 30, 2015, compared with $1.69/Bbl in the prior-year period 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.
The increase in gathering services and related fees during the nine months ended September 30, 2015 was primarily driven by the recognition of deferred revenue noted above and higher volume throughput on the Polar and Divide and Mountaineer Midstream systems. The aggregate average throughput rate decreased to $0.40/Mcf during the nine months ended September 30, 2015, compared with $0.43/Mcf in the prior-year period primarily as a result of a larger proportion of gathering fee revenue from Mountaineer Midstream. The aggregate average throughput rate for crude oil and produced water increased to $1.78/Bbl during the nine months ended September 30, 2015, compared with $1.59/Bbl in the prior-year period primarily as a result of the effect of contract amendments noted above.
Natural Gas, NGLs and Condensate Sales. The decrease in natural gas, NGLs and condensate sales for the three and nine months ended September 30, 2015 was primarily a result of the impact of declining commodity prices, partially offset by an increase in volumes on the Bison Midstream and Grand River Gathering systems that are subject to percent-of-proceeds arrangements. Declining commodity prices negatively impacted our percent-of-proceeds arrangements at Bison Midstream and Grand River Gathering, our fuel retainage revenue at DFW Midstream and condensate revenue for Grand River Gathering.
Costs and Expenses. Total costs and expenses increased $1.0 million, or 1%, for the three months ended September 30, 2015, primarily due to the recognition of long-lived asset impairments at Bison Midstream and Polar and Divide, a

general increase in depreciation and amortization and an increase in operation and maintenance primarily attributable to Polar Midstream. These increases were largely offset by a decrease in cost of natural gas and NGLs at Bison Midstream and Grand River Gathering.

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Total costs and expenses decreased $14.2 million, or 7%, for the nine months ended September 30, 2015 primarily due to a decrease in cost of natural gas and NGLs at Bison Midstream and Grand River Gathering. These decreases were partially offset by an increase in depreciation and amortization across our gathering systems and the long-lived asset impairments noted in the three-month comparison of costs and expenses.

Cost of Natural Gas and NGLs. The decrease in cost of natural gas and NGLs during the three and nine months ended September 30, 2015 was largely driven by declining commodity prices and the associated impact on our percent-of-proceeds arrangements at Bison Midstream and Grand River Gathering. This impact was partially offset by an increase in volume throughput for these arrangements.

Operation and Maintenance. Operation and maintenance expense increased during the three months ended September 30, 2015 primarily reflecting higher ad valorem taxes at Grand River Gathering, DFW Midstream and Polar Midstream, an increase in salaries, benefits and incentive compensation for DFW Midstream, Grand River Gathering and Polar Midstream, an increase in connection fee pass-through expense for Polar and Divide as a result of system expansion (revenue component is recognized in other revenues). 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 Gathering (revenue component is recognized in other revenues).

Operation and maintenance expense was flat during the nine months ended September 30, 2015 primarily reflecting a decline in electricity expense associated with DFW Midstream's electric-drive compression assets, a decline in pass-through electricity expense for Grand River Gathering (revenue component is recognized in other revenues), and a decline in contract services for Bison Midstream. These decreases were partially offset by an increase in connection fee pass-through expense for Polar and Divide as a result of system expansion (revenue component is recognized in other revenues) and an increase in salaries, benefits and incentive compensation across all systems.

General and Administrative. General and administrative expense decreased during the three months ended September 30, 2015 largely as a result of a decline in professional services expense. The substantial majority of this decline related to our 2014 adoption of Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

General and administrative expense decreased during the nine months ended September 30, 2015 primarily reflecting a decline in salaries, benefits and incentive compensation and a decrease in professional services expense. These decreases were partially offset by an increase in rent expenses.

Transaction Costs. Transaction costs recognized during the three and nine months ended September 30, 2015 primarily relate to financial and legal advisory costs associated with the Polar and Divide Drop Down.

Transaction costs recognized during the nine months ended September 30, 2014 primarily related to financial and legal advisory costs associated with the Red Rock Drop Down.

Depreciation and Amortization. The increase in depreciation and amortization expense during the three months ended September 30, 2015 was largely driven by an increase in assets placed into service primarily at Polar Midstream and Mountaineer Midstream as well as contract amortization primarily attributable to Grand River Gathering.

The increase in depreciation and amortization expense during the nine months ended September 30, 2015 was largely driven by an increase in assets placed into service across our gathering systems and contract amortization largely due to Grand River Gathering.

Interest Expense. The increase in interest expense during the three months ended September 30, 2015 was primarily driven by increased borrowings under our revolving credit facility.

The increase in interest expense during the nine months ended September 30, 2015 was primarily driven by our July 2014 issuance of the 5.5% senior notes.

Segment Overview of the Three and Nine Months Ended September 30, 2015 and 2014

Marcellus Shale. Mountaineer Midstream provides our midstream services for the Marcellus Shale reportable segment. Volume throughput averaged:

- 457 MMcf/d for the three months ended September 30, 2015, compared with 416 MMcf/d in the prior-year period and

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- 515 MMcf/d for the nine months ended September 30, 2015, compared with 357 MMcf/d in the prior-year period. The increase in volume throughput in 2015 was primarily driven by the upstream connection of wells owned by Mountaineer Midstream's anchor customer. Volume throughput for the third quarter of 2015 was down from an average of 542 MMcf/d in the second quarter of 2015 due to natural declines from existing wells behind the system and the continuance of Antero’s strategy to defer completion activities on certain wells located in the Marcellus Shale. We expect volumes on the Mountaineer Midstream system to increase beginning in the first half of 2016 as regional third-party takeaway pipeline infrastructure is commissioned, which is expected to improve producer netbacks for residue gas exiting the Sherwood Processing Complex. Additionally, we expect many of the deferred well completions to flow to the Sherwood Processing Complex via the Mountaineer Midstream system, beginning in the first half of 2016.

Information regarding our Marcellus Shale reportable segment follows.

	Marcellus Shale (1)							
	Three months ended September 30,		Percentage Change		Nine months ended September 30,		Percentage Change	
	2015	2014			2015	2014		
	(Dollars in thousands)							
Revenues:								
Gathering services and related fees	$6,963	$5,674	23	%	$22,585	$16,695	35	%
Total revenues	6,963	5,674	23	%	22,585	16,695	35	%
Costs and expenses:								
Operation and maintenance	1,083	1,147	(6	)%	3,817	3,371	13	%
General and administrative	85	571	(85	)%	276	1,648	(83	)%
Depreciation and amortization	2,170	1,853	17	%	6,508	5,515	18	%
Total costs and expenses	3,338	3,571	(7	)%	10,601	10,534	1	%
Add:								
Depreciation and amortization	2,170	1,853			6,508	5,515		
Segment adjusted EBITDA	$5,795	$3,956	46	%	$18,492	$11,676	58	%
Average throughput (MMcf/d)	457	416	10	%	515	357	44	%

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(1) Contract terms related to throughput rate per MCF are excluded for confidentiality purposes.

Three and nine months ended September 30, 2015. Segment adjusted EBITDA increased $1.8 million during the three months ended September 30, 2015 and $6.8 million during the nine months ended September 30, 2015 reflecting:

- the impact of an increase in volume throughput which translated into higher gathering services and related fees revenue.
- for the nine-month period, the benefit of higher volume throughput was partially offset by a decline in compression services, which resulted from a larger year-to-date percentage of previously compressed natural gas entering our gathering lines. As a result, the proportion of high-pressure gathering services increased, which, due to its lower rate relative to compression fees, negatively impacted the average throughput rate per Mcf.
- minimum revenue commitment payments related to the Zinnia Loop project, beginning in the first quarter of 2015.
- a decline in general and administrative expenses primarily as a result of our decision to discontinue allocating certain corporate general and administrative expenses beginning in the first quarter of 2015.
- for the nine-month period, an increase in operation and maintenance primarily as a result of system expansion and the associated increase in volume throughput.

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Depreciation and amortization increased during the three and nine months ended September 30, 2015 largely as a result of commissioning the Zinnia Loop project.

Williston Basin – Gas. Bison Midstream provides our midstream services for the Williston Basin – Gas reportable segment. Volume throughput averaged:

- 17 MMcf/d for the three months ended September 30, 2015, compared with 21 MMcf/d in the prior-year period and
- 17 MMcf/d for the nine months ended September 30, 2015, compared with 16 MMcf/d in the prior-year period.

The decrease in volume throughput during the three months ended September 30, 2015 primarily reflects the impact of a customer's decision to divert their wells late in the first quarter of 2015, partially offset by compression capacity installed in the latter half of 2014, which improved system hydraulics. Volume throughput for the nine months ended September 30, 2015 was flat due to the impact of the customer diverting their production, partially offset by severe winter weather in northwestern North Dakota and the impact of operational challenges caused by water hydrate issues both in the first quarter of 2014. The water hydrate issues were remediated during the second quarter of 2014.

Bison Midstream's average throughput rate was:

- $2.47/Mcf during the three months ended September 30, 2015, compared with $3.15/Mcf in the prior-year period and
- $2.59/Mcf during the nine months ended September 30, 2015, compared with $3.68/Mcf in the prior-year period.

These declines were primarily a result of the impact of declining commodity prices and a larger proportion of volumes associated with percent-of-proceeds contracts.

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Information regarding our Williston Basin – Gas reportable segment follows.

	Williston Basin – Gas			Nine months ended September 30,		
	Three months ended September 30,		Percentage Change			Percentage Change
	2015	2014		2015	2014	
	(Dollars in thousands, except fee-rate data)					
Revenues:						
Gathering services and related fees	$249	$241	3 %	$732	$673	9 %
Natural gas, NGLs and condensate sales	4,959	14,136	(65)%	18,208	42,938	(58)%
Other revenues	1,182	1,588	(26)%	3,814	3,936	(3)%
Total revenues	6,390	15,965	(60)%	22,754	47,547	(52)%
Costs and expenses:						
Cost of natural gas and NGLs	1,533	8,368	(82)%	6,775	27,515	(75)%
Operation and maintenance	3,083	4,375	(30)%	9,307	10,808	(14)%
General and administrative	144	852	(83)%	468	2,696	(83)%
Depreciation and amortization	4,830	4,690	3 %	14,306	13,428	7 %
Loss on asset sales	—	—	*	—	6	*
Long-lived asset impairment	6,697	—	*	6,697	—	*
Total costs and expenses	16,287	18,285	(11)%	37,553	54,453	(31)%
Add:						
Depreciation and amortization	4,830	4,690		14,306	13,428	
Adjustments related to MVC shortfall payments	3,470	2,744		8,970	8,069	
Loss on asset sales	—	—		—	6	
Long-lived asset impairment	6,697	—		6,697	—	
Segment adjusted EBITDA	$5,100	$5,114	— %	$15,174	$14,597	4 %
Average throughput (MMcf/d)	17	21	(19)%	17	16	6 %
Average throughput rate per Mcf	$2.47	$3.15	(22)%	$2.59	$3.68	(30)%

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* Not considered meaningful

Three and nine months ended September 30, 2015. Segment adjusted EBITDA was flat during the three months ended September 30, 2015 and increased $0.6 million during the nine months ended September 30, 2015 reflecting:

- the impact of declining commodity prices which negatively affected the margins we earn under percent-of-proceeds arrangements.
- the previously mentioned decision to discontinue certain corporate general and administrative expense allocations.
- for the three-month period, a decrease in operation and maintenance expenses reflecting the impact of an adjustment to our estimate of property tax expense in 2015.
- for the nine-month period, a decrease in operation and maintenance expenses reflecting lower contract services expenses, the first quarter 2014 water hydrate remediation effort and the impact of adjusting our estimate for property tax expense in 2015.

The long-lived asset impairment reflects our September 2015 decision to impair certain property, plant and equipment balances associated with terminated projects. Depreciation and amortization increased during the nine months ended September 30, 2015 largely as a result of compression assets placed into service during the second half of 2014.

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Williston Basin – Liquids. Polar and Divide provides our midstream services for the Williston Basin – Liquids reportable segment. Volume throughput averaged:

- 51.5 Bbl/d for the three months ended September 30, 2015, compared with 33.5 Bbl/d in the prior-year period and
- 51.3 Bbl/d for the nine months ended September 30, 2015, compared with 29.1 Bbl/d in the prior-year period.

The increase in volume throughput in 2015 reflects new pad site connections and ongoing drilling activity in Polar and Divide's service area. For the three-month period, volume throughput was impacted by construction activities designed to enhance pipeline integrity and increase capacity on a produced water pipeline. This effort caused the produced water pipeline to be out of service for most of the third quarter of 2015; it was returned to service mid-October.

Polar and Divide's average throughput rate was:

- $1.77/Bbl during the three months ended September 30, 2015, compared with $1.69/Bbl in the prior-year period and
- $1.78/Bbl during the nine months ended September 30, 2015, compared with $1.59/Bbl in the prior-year period.

The increase in average throughput rate 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.

Information regarding our Williston Basin – Liquids reportable segment follows.

	Williston Basin – Liquids							
	Three months ended September 30,		Percentage Change		Nine months ended September 30,		Percentage Change	
	2015	2014			2015	2014		
	(Dollars in thousands, except fee-rate data)							
Revenues:								
Gathering services and related fees	$8,396	$5,190	62	%	$24,947	$12,661	97	%
Other revenues	1,167	564	107	%	3,103	1,460	113	%
Total revenues	9,563	5,754	66	%	28,050	14,121	99	%
Costs and expenses:								
Operation and maintenance	3,635	1,808	101	%	8,531	5,195	64	%
General and administrative	209	1,054	(80	)%	2,342	3,204	(27	)%
Depreciation and amortization	1,839	1,168	57	%	5,186	2,860	81	%
Long-lived asset impairment	999	—	*		999	—	*	
Total costs and expenses	6,682	4,030	66	%	17,058	11,259	52	%
Add:								
Depreciation and amortization	1,839	1,168			5,186	2,860		
Unit-based compensation	—	85			85	255		
Long-lived asset impairment	999	—			999	—		
Segment adjusted EBITDA	$5,719	$2,977	92	%	$17,262	$5,977	*	
Average throughput (Mbbl/d)	51.5	33.5	54	%	51.3	29.1	76	%
Average throughput rate per Bbl	$1.77	$1.69	5	%	$1.78	$1.59	12	%

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* Not considered meaningful

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Three and nine months ended September 30, 2015. Segment adjusted EBITDA increased $2.7 million during the three months ended September 30, 2015 and $11.3 million during the nine months ended September 30, 2015 reflecting:
- the impact of higher volume throughput on gathering services and related fees.
- higher gathering rates associated with contract amendments in 2014.
- an increase in operation and maintenance expenses largely as a result of system buildout.
- the previously mentioned decision to discontinue certain corporate general and administrative expense allocations.

Other revenues and operation and maintenance also reflect the effect of an increase in connection fees, which, due to their pass-through nature, have no impact on segment adjusted EBITDA. Depreciation and amortization increased during the three and nine months ended September 30, 2015 largely as a result of gathering pipeline placed into service during 2014. The long-lived asset impairment reflects our September 2015 decision to impair certain property, plant and equipment balances associated with terminated projects.

Barnett Shale. DFW Midstream provides our midstream services for the Barnett Shale reportable segment. Volume throughput averaged:
- 325 MMcf/d during the three months ended September 30, 2015, compared with 361 MMcf/d in the prior-year period and
- 361 MMcf/d during the nine months ended September 30, 2015, compared with 353 MMcf/d in the prior-year period.

Volume throughput decreased during the three months ended September 30, 2015 primarily reflecting drilling and completion activities by certain customers which restrained production and a lack of drilling activity by DFW Midstream's anchor customer. These decreases were partially offset by the contribution from the Lonestar assets (acquired September 30, 2014). The increase in volume throughput for the year-to-date period primarily reflects first quarter 2015 customer production which recommenced from several pad sites that had been temporarily shut-in for drilling and completion activities beginning in the third quarter of 2013 and continuing until late 2014 as well as the contribution of the Lonestar assets. These increases were partially offset by the impact of drilling and completion activities during the second and third quarters of 2015, including the lack of drilling by DFW Midstream's anchor customer.

DFW Midstream's average throughput rate was:
- $0.58/Mcf during the three months ended September 30, 2015, compared with $0.57/Mcf in the prior-year period and
- $0.62/Mcf during the nine months ended September 30, 2015, compared with $0.59/Mcf in the prior-year period.

The increase in average throughput rate for the three and nine months ended September 30, 2015 is primarily the result of a shift in volume mix.

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Information regarding our Barnett Shale reportable segment follows.

	Barnett Shale Three months ended September 30, 2015	2014	Percentage Change	Nine months ended September 30, 2015	2014	Percentage Change
	(Dollars in thousands, except fee-rate data)					
Revenues:						
Gathering services and related fees	$18,017	$19,680	(8)%	$61,692	$59,417	4%
Natural gas, NGLs and condensate sales	1,565	3,259	(52)%	5,185	11,193	(54)%
Other revenues	206	(202)	*	631	(595)	*
Total revenues	19,788	22,737	(13)%	67,508	70,015	(4)%
Costs and expenses:						
Operation and maintenance	6,648	6,436	3%	19,796	21,967	(10)%
General and administrative	268	1,173	(77)%	1,001	3,536	(72)%
Depreciation and amortization	3,896	3,725	5%	11,704	11,102	5%
Total costs and expenses	10,812	11,334	(5)%	32,501	36,605	(11)%
Add:						
Depreciation and amortization	4,081	3,968		12,352	11,795	
Adjustments related to MVC shortfall payments	86	246		(1,915)	404	
Segment adjusted EBITDA	$13,143	$15,617	(16)%	$45,444	$45,609	—%
Average throughput (MMcf/d)	325	361	(10)%	361	353	2%
Average throughput rate per Mcf	$0.58	$0.57	2%	$0.62	$0.59	5%

*Not considered meaningful

Three and nine months ended September 30, 2015. Segment adjusted EBITDA decreased $2.5 million during the three months ended September 30, 2015 and $0.2 million during the nine months ended September 30, 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.
- for the three-month period, a decrease in gathering services and related fees due to lower volumes.
- for the nine-month period, an increase in gathering services and related fees due to higher volumes in the first quarter of 2015.
- 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.
- for the three-month period, the impact of adjusting upward our estimate for property tax expense in 2015, an increase in third-party natural gas treating expenses, which we recognize in operation and maintenance, and an increase in compression expenses. These increases were partially offset by the decline in electricity expense noted above.
- for the nine-month period, a decline in operation and maintenance expense primarily due to the decline in electricity expense noted above. This decline was partially offset by an increase in compression expense, a reduction in capitalized labor relative to the prior-year period and the impact of adjusting upward our estimate for property tax expense in 2015.
- adjustments due to the expiration of deferred revenue credits in April 2015.

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- the previously mentioned decision to discontinue certain corporate general and administrative expense allocations.

Depreciation and amortization increased during the three and nine months ended September 30, 2015 largely as a result of placing the Lonestar assets into service in September 2014.

Piceance Basin. Grand River Gathering provides our midstream services for the Piceance Basin reportable segment. Red Rock Gathering became part of the Grand River Gathering system in connection with the Red Rock Drop Down in March 2014. Our results include activity for Red Rock Gathering for all periods presented.

Volume throughput averaged:

- 591 MMcf/d during the three months ended September 30, 2015, compared with 667 MMcf/d during the prior-year period and
- 604 MMcf/d during the nine months ended September 30, 2015, compared with 667 MMcf/d during the prior-year period.

The declines in volume were primarily a result of Encana's temporary suspension of drilling activities, which began in the fourth quarter of 2013. This decline was partially offset by new pad site connections, and, for the nine-month period, the March 2014 start-up of a cryogenic processing plant.

The average throughput rate was:

- $0.42/Mcf during the three months ended September 30, 2015, compared with $0.42/Mcf during the prior-year period and
- $0.42/Mcf during the nine months ended September 30, 2015, compared with $0.40/Mcf during prior-year period.

The change in average throughput rates for the three- and nine-month periods largely reflect a shift in volume mix.

Certain of our gas gathering agreements for Grand River Gathering include MVCs that mitigate the financial impact associated with declining volumes from certain customers. As a result, lower volume throughput for the customers subject to these MVCs translated into larger MVC shortfall payments.

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Information regarding our Piceance Basin reportable segment follows.

	Piceance Basin Three months ended September 30, 2015	2014	Percentage Change		Nine months ended September 30, 2015	2014	Percentage Change	
	(Dollars in thousands, except fee-rate data)							
Revenues:								
Gathering services and related fees	$57,060	$25,813	121	%	$102,866	$72,913	41	%
Natural gas, NGLs and condensate sales	2,186	6,575	(67	)%	9,897	22,846	(57	)%
Other revenues	1,299	2,266	(43	)%	4,024	6,012	(33	)%
Total revenues	60,545	34,654	75	%	116,787	101,771	15	%
Costs and expenses:								
Cost of natural gas and NGLs	2,119	4,474	(53	)%	7,166	14,800	(52	)%
Operation and maintenance	8,596	8,074	6	%	24,267	25,127	(3	)%
General and administrative	592	2,198	(73	)%	1,786	6,682	(73	)%
Depreciation and amortization	11,239	10,626	6	%	33,653	30,687	10	%
Gain on asset sales	—	—	*		(214)	—	100	%
Total costs and expenses	22,546	25,372	(11	)%	66,658	77,296	(14	)%
Add:								
Depreciation and amortization	11,239	10,626			33,653	30,687		
Adjustments related to MVC shortfall payments	(24,910)	8,230			(5,141)	25,337		
Less gain on asset sales	—	—			214	—		
Segment adjusted EBITDA	$24,328	$28,138	(14	)%	$78,427	$80,499	(3	)%
Average throughput (MMcf/d)	591	667	(11	)%	604	667	(9	)%
Average throughput rate per Mcf	$0.42	$0.42	—	%	$0.42	$0.40	5	%

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* Not considered meaningful

Three months ended September 30, 2015. Segment adjusted EBITDA decreased $3.8 million during the three months ended September 30, 2015 reflecting:

- lower gathering services revenue from our anchor customer.
- the previously mentioned decision to discontinue certain corporate general and administrative expense allocations.
- an increase in anticipated MVC shortfall payments due to increasing rate and volume commitment provisions in certain gas gathering agreements.
- the impact of declining commodity prices which negatively impacted the margins that we earn from our percent-of-proceeds contracts and the condensate drip that we retain.
- a increase in operation and maintenance due to higher property taxes and an increase in repair expense.

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 release of the deferred revenue from our Piceance Segment during the three months ended September 30, 2015. 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 three months ended September 30, 2015 largely as a result of an increase in contract amortization for Grand River Gathering's anchor customer.

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Nine months ended September 30, 2015. Segment adjusted EBITDA decreased $2.1 million during the nine months ended September 30, 2015 reflecting:

- the previously mentioned decision to discontinue certain corporate general and administrative expense allocations.
- the impact of declining commodity prices which negatively impacted the margins that we earn from our percent-of-proceeds contracts.
- 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.
- lower gathering services revenue from our anchor customer.

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 release of the deferred revenue from our Piceance Segment during the nine months ended September 30, 2015. 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 nine months ended September 30, 2015 largely as a result of an increase in contract amortization for Grand River Gathering's anchor customer and the March 2014 commissioning of a cryogenic processing plant.

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							
	Three months ended September 30,		Percentage Change		Nine months ended September 30,		Percentage Change	
	2015	2014			2015	2014		
	(In thousands)							
Costs and expenses:								
General and administrative	$7,416	$3,566	108	%	$21,873	$10,361	111	%
Transaction costs	119	62	92	%	714	675	6	%
Depreciation and amortization	138	142	(3	)%	488	426	15	%
Interest expense	12,132	10,558	15	%	36,333	28,504	27	%

General and Administrative. The increase in general and administrative expense during the three and nine months ended September 30, 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.

Transaction Costs. Transaction costs recognized during the three and nine months ended September 30, 2015 primarily relate to financial and legal advisory costs associated with the Polar and Divide Drop Down.

Transaction costs recognized during the nine months ended September 30, 2014 primarily relate to financial and legal advisory costs associated with the Red Rock Drop Down.

Interest Expense. The increase in interest expense during the three months ended September 30, 2015, was primarily driven by increased borrowings under our revolving credit facility.

The increase in interest expense during the nine months ended September 30, 2015, was primarily driven by our July 2014 issuance of the 5.5% senior notes.

Non-GAAP Financial Measures

EBITDA, adjusted EBITDA and distributable cash flow are not financial measures presented in accordance with GAAP. We define EBITDA as net income, plus interest expense, income tax expense, and depreciation and

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amortization, less interest income and income tax benefit. We define adjusted EBITDA as EBITDA plus adjustments related to MVC shortfall payments, impairments and other noncash expenses or losses, less other noncash income or gains. We define distributable cash flow as adjusted EBITDA plus cash interest received, less cash interest paid, senior notes interest, 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 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. For additional information on the limitations of our non-GAAP financial measures and how we compensate for those limitations, see the "Non-GAAP Financial Measures" section of MD&A included in the 2014 Annual Report.

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 unaudited condensed consolidated statements of cash flows for additional information.
- Depreciation and amortization includes the favorable and unfavorable gas gathering contract amortization expense reported in other revenues.
- Adjustments related to MVC shortfall payments account for (i) the net increases or decreases in deferred revenue for MVC shortfall payments and (ii) our inclusion of expected annual MVC shortfall payments. See Notes 2 and 3 to the unaudited condensed consolidated financial statements.
- Senior notes interest represents the net of interest expense accrued and paid during the period. See "Liquidity and Capital Resources—Long-Term Debt" and Note 7 to the consolidated financial statements included in the 2014 Annual Report.
- 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 Polar Midstream, Epping and Red Rock Gathering for the periods beginning with the date that common control began and ending on the date that the respective drop down closed. See Notes 1 and 15 to the unaudited condensed consolidated financial statements and Note 15 to the consolidated financial statements included in the 2014 Annual Report.
- EBITDA, adjusted EBITDA, distributable cash flow and net cash provided by operating activities include transaction costs. These unusual expenses are settled in cash. For additional information, see "Results of Operations—Corporate" herein.

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

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
	(In thousands)			
Reconciliation of net income to EBITDA, adjusted EBITDA and distributable cash flow:				
Net income	$23,604	$7,837	$33,659	$19,384
Add:				
Interest expense	12,132	10,558	36,333	28,504
Income tax expense	176	28	248	655
Depreciation and amortization	24,297	22,447	72,493	64,711
Less interest income	1	1	2	3
EBITDA	$60,208	$40,869	$142,731	$113,251
Add:				
Adjustments related to MVC shortfall payments	(21,354)	11,220	1,914	33,810
Unit-based compensation	1,905	1,160	5,039	3,754
Loss on asset sales	—	—	—	6
Long-lived asset impairment	7,696	—	7,696	—
Less gain on asset sales	—	—	214	—
Adjusted EBITDA	$48,455	$53,249	$157,166	$150,821
Add cash interest received	1	1	2	3
Less:				
Cash interest paid	21,703	12,626	46,434	29,779
Senior notes interest	(9,750)	(2,142)	(11,171)	(3,017)
Maintenance capital expenditures	2,083	4,186	6,797	14,588
Distributable cash flow	$34,420	$38,580	$115,108	$109,474

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

	Nine months ended September 30,	
	2015	2014
	(In thousands)	
Reconciliation of net cash provided by operating activities to EBITDA, adjusted EBITDA and distributable cash flow:		
Net cash provided by operating activities	$121,889	$115,053
Add:		
Interest expense, excluding deferred loan costs	33,921	26,534
Income tax expense	248	655
Changes in operating assets and liabilities	(804)	(25,228)
Gain on asset sales	214	—
Less:		
Unit-based compensation	5,039	3,754
Interest income	2	3
Loss on asset sales	—	6
Long-lived asset impairment	7,696	—
EBITDA	$142,731	$113,251
Add:		
Adjustments related to MVC shortfall payments	1,914	33,810
Unit-based compensation	5,039	3,754
Loss on asset sales	—	6
Long-lived asset impairment	7,696	—
Less gain on asset sales	214	—
Adjusted EBITDA	$157,166	$150,821
Add cash interest received	2	3
Less:		
Cash interest paid	46,434	29,779
Senior notes interest	(11,171)	(3,017)
Maintenance capital expenditures	6,797	14,588
Distributable cash flow	$115,108	$109,474

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 securities.

Capital Markets Activity

We had no capital markets activity during the nine months ended September 30, 2015, except as noted below.

November 2013 Shelf Registration Statement. 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. 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 three months ended September 30, 2015.

For additional information, see the "Liquidity and Capital Resources—Capital Markets Activity" section of MD&A included in the 2014 Annual Report.

Long-Term Debt

Revolving Credit Facility. We have a $700.0 million senior secured revolving credit facility. The revolving credit facility is secured by the membership interests of Summit Holdings and those of its subsidiaries. Substantially all of 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 September 30, 2015, the outstanding balance of the revolving credit facility was $304.0 million and the unused portion totaled $396.0 million. As of September 30, 2015, we were in compliance with the covenants in the revolving credit facility. There were no defaults or events of default during the nine months ended September 30, 2015.

Senior Notes. In July 2014, Summit Holdings and Summit Midstream Finance Corp. co-issued $300.0 million of 5.50% senior unsecured notes maturing August 15, 2022. In June 2013, they co-issued $300.0 million of 7.50% senior unsecured notes maturing July 1, 2021. There were no defaults or events of default during the nine months ended September 30, 2015 on either series of senior notes.

For additional information, see Note 8 to the unaudited condensed consolidated financial statements.

Cash Flows

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

	Nine months ended September 30,	
	2015	2014
	(In thousands)	
Net cash provided by operating activities	$121,889	$115,053
Net cash used in investing activities	(377,670)	(470,553)
Net cash provided by financing activities	234,736	349,276
Net change in cash and cash equivalents	$(21,045)	$(6,224)

Operating activities. Cash flows from operating activities increased by $6.8 million for the nine months ended September 30, 2015 primarily due to cash received as a result of MVCs. The impact of these cash receipts was largely offset by an increase in interest due to the 5.5% senior notes and other operating activities.

Investing activities. Cash flows used in investing activities for the nine months ended September 30, 2015 were related primarily to: (i) the Polar and Divide Drop Down (net of a working capital and capital expenditures adjustment), (ii) the ongoing expansion of compression capacity on the Bison Midstream system, (iii) ongoing expansion of the Polar and Divide system, including the Stampede Lateral, (iv) pipeline construction projects to connect new receipt points on the Grand River and Bison Midstream systems and (v) the settlement of the working capital adjustment associated with the Red Rock Drop Down.

Cash flows used in investing activities for the nine months ended September 30, 2014 reflect the Partnership's acquisition of Red Rock Gathering from an affiliate of Summit Investments. Additional expenditures in the nine months ended September 30, 2014 primarily reflect: (i) construction of a processing plant on the Grand River

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Gathering system, (ii) projects to expand compression capacity on the Bison Midstream system, (iii) adding pipeline on the Mountaineer Midstream system, (iv) the February 2014 commissioning of a new natural gas treating facility on the DFW Midstream system and (v) the purchase of the Lonestar assets on September 30, 2014.

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

Net cash used in financing activities for the nine months ended September 30, 2015 was primarily composed of the following:

- Net proceeds from an offering of common units in May 2015, which were used to partially fund the Polar and Divide Drop Down;
- Net borrowings under our revolving credit facility, including $92.5 million to partially fund the Polar and Divide Drop Down; and
- Distributions declared in respect of the second quarter of 2015, the first quarter of 2015 and the fourth quarter of 2014 (paid in the first quarter of 2015).

Net cash provided by financing activities for the nine months ended September 30, 2014 was primarily composed of the following:

- Proceeds from the July 2014 issuance of 5.5% senior notes, 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 5.5% senior 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; and
- Distributions declared in respect of the second quarter of 2014, the first quarter of 2014 and the fourth quarter of 2013 (paid in the first quarter of 2014).

Capital Requirements

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

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

For the nine months ended September 30, 2015, SMLP recorded total capital expenditures of $89.3 million, which included $6.8 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 securities.

We believe that our existing $700.0 million revolving credit facility, which had approximately $396.0 million of available capacity at September 30, 2015, together with our 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

Based on the terms of our partnership agreement, we expect to distribute to unitholders most of the cash generated by our operations. For additional information, see Note 10 to the unaudited condensed consolidated financial statements.

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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.
We estimate the quarterly impact of expected MVC shortfall payments for inclusion in our calculation of distributable cash flow. 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 have received payment for all prior-year MVC shortfall payments. 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 nine months ended September 30, 2015 follow.

	Williston Basin - Gas	Barnett Shale	Piceance Basin	Total
	(In thousands)			
Adjustments related to MVC shortfall payments:				
Net change in deferred revenue for MVC shortfall payments (1)	$(27)	$(1,700)	$(22,879)	$(24,606)
Expected MVC shortfall payments	8,997	(215)	17,738	26,520
Total adjustments related to MVC shortfall payments	$8,970	$(1,915)	$(5,141)	$1,914

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(1) See Note 7 for additional information on the changes in deferred revenue.
As of September 30, 2015, adjustments related to MVC shortfall payments included $26.5 million of expected MVC shortfall payments for which we are at risk of customer nonperformance.
For additional information, see Notes 2, 3, 7 and 9 to the unaudited condensed consolidated financial statements.
Off-Balance Sheet Arrangements
We had no off-balance sheet arrangements as of or during the nine months ended September 30, 2015.

Critical Accounting Estimates
We prepare our financial statements in accordance with GAAP. These principles are established by the FASB. 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 unaudited condensed 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.
There have been no changes in the accounting methodology for items that we have identified as critical accounting estimates during the nine months ended September 30, 2015.
Recognition and Impairment of Long-Lived Assets
Goodwill. We have three reporting units which have goodwill: Grand River Gathering, Polar Midstream and Mountaineer Midstream. 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 value, including goodwill.
Annual Impairment Evaluation. We test goodwill for impairment using a two-step quantitative test. In the first step, we compare the fair value of the reporting unit to its carrying value, including goodwill. If the reporting unit’s fair value exceeds its carrying value, including goodwill, 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, including goodwill, exceeds its fair value, we proceed to step two. In step two, we compare the carrying value of the reporting

unit, including goodwill, to its implied fair value. If we determine that the carrying value of a reporting unit, including

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goodwill, exceeds its implied fair value, we recognize the excess of the carrying value over the implied fair value as a goodwill impairment loss.

We performed our annual goodwill impairment analysis as of September 30, 2015. To complete step one of the evaluation, we utilized significant estimates and assumptions in developing enterprise values for:

- the Grand River Gathering reporting unit (acquired in October 2011), which includes Red Rock Gathering (acquired in March 2014 from an affiliate of Summit Investments, which acquired the underlying gas gathering system in October 2012);
- the Polar Midstream reporting unit (acquired in May 2015 from an affiliate of Summit Investments, which acquired the underlying gas gathering system in February 2013); and
- the Mountaineer Midstream reporting unit (acquired in June 2013).

Furthermore, because the Red Rock Drop Down and the Polar and Divide Drop Down were determined to be transactions among entities under common control, we recognized the assets acquired and the liabilities assumed in connection with those drop down transactions at historical cost at the time of the respective drop down transaction.

To estimate the enterprise value, we utilized two valuation methodologies: the market approach and the income approach. The most significant estimates and assumptions inherent within these two valuation methodologies were:

- selection of the discount rate;
- guideline public companies;
- market multiples;
- weighted-average cost of capital;
- weighting of the income and market approaches;
- growth rates; and
- the expected levels of throughout volume gathered.

Changes in the above and other assumptions could materially affect the calculated amount of enterprise value for any of our reporting units.

We determined that the fair value of all three reporting units substantially exceeded their carrying value, including goodwill. Because the fair values of all three reporting units exceeded their carrying values, including goodwill, there have been no impairments of goodwill in connection with our 2015 annual goodwill impairment test.

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

Bison Midstream Fourth Quarter 2014 Goodwill Impairment. As of December 31, 2014, our preliminary estimates of the fair values of the identified assets and liabilities calculated in the step two testing of the Bison Midstream reporting unit indicated that all of the associated goodwill had been impaired. In the first quarter of 2015, we finalized our calculations of the fair values of the identified assets and liabilities, confirming the preliminary goodwill impairment of $54.2 million. For additional information, see Note 6 to the unaudited condensed consolidated financial statements and Note 5 to the consolidated financial statements included in the 2014 Annual Report.

Minimum Volume Commitments

Certain of our gas gathering agreements provide for a monthly, quarterly or annual MVC from our customers. As of September 30, 2015, we had MVCs totaling 1.3 Bcfe/d through 2019.

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.

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 September 30, 2015, current deferred revenue totaled $0.7 million. Noncurrent deferred revenue totaled $32.3 million at September 30, 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 7 to the unaudited condensed consolidated financial statements and the "Results of Operations" and "Liquidity and Capital Resources—Credit and Counterparty Concentration Risks" sections herein.

For additional information regarding critical accounting estimates generally, see the "Critical Accounting Estimates" section of MD&A included in the 2014 Annual Report.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

Interest Rate Risk

We have exposure to changes in interest rates on our indebtedness associated with the revolving credit facility. Our current interest rate risk exposure has not changed materially since December 31, 2014. See the "Interest Rate Risk" section included in Item 7A. Quantitative and Qualitative Disclosures About Market Risk of the 2014 Annual Report for additional information.

Commodity Price Risk

We currently generate a substantial majority of our revenues pursuant to primarily long-term and fee-based gathering and processing agreements, many of which include MVCs and areas of mutual interest. Our direct commodity price exposure relates to (i) our sale of physical natural gas we retain from our DFW Midstream customers, (ii) our procurement of electricity to operate our electric-drive compression assets on the DFW Midstream system, (iii) the sale of condensate volumes that we retain on the Grand River Gathering system and (iv) the sale of processed natural gas and natural gas liquids pursuant to our percent-of-proceeds and keep-whole contracts with certain of our customers on the Bison Midstream and Grand River Gathering systems. Our current commodity price risk exposure has not changed materially since December 31, 2014. See the "Commodity Price Risk" section included in Item 7A. Quantitative and Qualitative Disclosures About Market Risk of the 2014 Annual Report for additional information.

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Item 4. Controls and Procedures.

Under the direction of our general partner's Chief Executive Officer and Chief Financial Officer, we evaluated our disclosure controls and procedures and internal control over financial reporting and concluded that (i) our disclosure controls and procedures were effective as of September 30, 2015 and (ii) no change in internal control over financial reporting occurred during the quarter ended September 30, 2015, that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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PART II—OTHER INFORMATION

Item 1. Legal Proceedings.

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, and except as previously reported in Item 3. Legal Proceedings of the 2014 Annual Report, we are not currently a party to any significant legal or governmental proceedings.

Item 1A. Risk Factors.

The risk factors contained in the Item 1A. Risk Factors of the 2014 Annual Report are incorporated herein by reference except to the extent they address risks arising from or relating to the failure of events described therein to occur, which events have since occurred. Risk Factors that have (i) changed materially or (ii) been added are set forth below.

We intend to grow our business in part by seeking strategic acquisition opportunities. If we are unable to make acquisitions on economically acceptable terms from Summit Investments, its affiliates or third parties, our future growth will be affected, and the acquisitions we do make may reduce, rather than increase, our cash generated from operations. Our ability to grow depends, in part, on our ability to make acquisitions that increase our cash generated from operations. The acquisition component of our strategy also relies, in part, on the continued divestiture of midstream assets by industry participants. A material decrease in such divestitures would limit our opportunities for future acquisitions and could materially adversely affect our ability to grow our operations and increase our cash distributions to our unitholders.

If we are unable to make accretive acquisitions from Summit Investments, its affiliates or third parties, whether because we are (i) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts; (ii) unable to obtain financing for these acquisitions on economically acceptable terms; (iii) outbid by competitors; or (iv) unable to obtain necessary governmental or third-party consents or for any other reason, then our future growth and ability to increase cash distributions on a per-unit basis will be limited. Furthermore, as we recently announced, Energy Capital Partners, our Sponsor, is exploring strategic options for its ownership interest in Summit Investments thus creating uncertainty with respect to our ability to acquire assets from Summit Investments. It is not clear whether Summit Investments intends to offer us any acquisition opportunities while it and Energy Capital Partners are exploring strategic options and, to the extent the process results in a sale of Energy Capital Partners' ownership interest in Summit Investments, whether a new owner of Summit Investments would continue to offer us acquisition opportunities. If we are unable to acquire assets from Summit Investments in the near or long term it may adversely affect our ability to grow our business. We cannot be certain whether a transaction involving Summit Investments will be completed or, if so, when. Even if we do make acquisitions that we believe will be accretive, these acquisitions may nevertheless result in a decrease in the cash generated from operations. Any acquisition involves potential risks, including, among other things:

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

If we consummate any future acquisitions, our capitalization, results of operations and future growth may change significantly and our unitholders will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in deciding to engage in these future acquisitions, which may reduce, rather than increase, our cash generated from operations.

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

As we recently announced, Energy Capital Partners, the private equity firm that indirectly owns and controls Summit Investments, is exploring strategic options for its ownership interest in Summit Investments. Although we cannot predict whether or when any transaction may be consummated, if Energy Capital Partners consummates a transaction involving a sale or other disposition of its interests in Summit Investments, the transaction would result in a change in control of SMLP because Summit Investments indirectly owns and controls our general partner. In addition, our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, our partnership agreement does not restrict the ability of Summit Investments to transfer all or a portion of its ownership interest in our general partner to a third party. The new owner of Summit Investments, or new members of our general partner, as applicable, would then be in a position to replace the board of directors and officers of our general partner with their own designees and thereby exert significant control over the decisions made by the board of directors and officers. This effectively permits a change of control without the vote or consent of the unitholders.

We may not have the funds necessary to finance the repurchase of our outstanding senior notes in connection with a change of control offer required by our indentures.

Under the terms of our senior notes indentures, a "Change of Control" will occur if, among other things, any person acquires a controlling interest in Summit Investments, or any person (other than Summit Investments and its subsidiaries) obtains a controlling interest in us or our general partner. Upon the occurrence of specific kinds of change of control events, the indentures governing our outstanding senior notes will require us to make an offer to repurchase all such notes at 101% of the principal amount thereof, plus accrued and unpaid interest to the date of repurchase. However, it is possible that we will not have sufficient funds, or the ability to raise sufficient funds, at the time of the change of control to make the required repurchase of the notes. In addition, restrictions under our revolving credit facility may not allow us to make such a repurchase upon a change of control. If we could not refinance the revolving credit facility or otherwise obtain a waiver from the holders of such debt, we would be prohibited from repurchasing the notes, which would constitute an event of default under the indentures.

Our recent announcement that Energy Capital Partners is exploring strategic options for its ownership interest in Summit Investments creates uncertainty that could adversely affect our ability to secure new customers or increase or extend agreements with existing customers, or to enter into or retain business relationships that are important to our operations, any of which could materially and adversely affect our business or results of operations.

Our recent announcement that Energy Capital Partners is exploring strategic options for its ownership interest in Summit Investments creates uncertainty for our business. Because Energy Capital Partners indirectly owns and controls Summit Investments, which indirectly owns and controls our general partner and SMLP, a sale or other disposition of its ownership in Summit Investments would constitute a change in control of SMLP. Furthermore, we cannot be certain whether a transaction that would result in a change in control of SMLP will be completed or, if so, when. This uncertainty may adversely affect our ability to enter into new customer agreements or extend or expand existing customer relationships if potential and existing customers choose to wait to learn the identity of the acquirer, if any, of Energy Capital Partners’ controlling interests before committing to new, extended or expanded customer relationships with us. Similarly, suppliers, vendors and other businesses that we may seek to contract with or expand existing relationships with may choose to wait to enter into new agreements or arrangements or change existing agreements or arrangements with us. If such uncertainty continues for a protracted period, our ability to secure new, extended or expanded customer relationships may be adversely affected, or we may be compelled to pay higher fees or incur new or higher expenses to operate and maintain our business. We cannot predict whether or when any adverse effects on our business will result from these uncertainties, but such effects, if any, could materially and adversely affect our revenues and results of operations in future periods.

A change of control transaction would constitute a default under our revolving credit facility unless we are able to secure necessary consents, waivers or amendments from the counterparties to such agreements.

Under the terms of our revolving credit facility, which we use to finance our operations and to secure letters of credit required in connection with agreements with our customers, suppliers and vendors, a "Change of Control" will occur

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if, among other things, any person acquires a controlling interest in Summit Investments, or any person (other than Summit Investments and its subsidiaries) obtains a controlling interest in our general partner or our general partner ceases to own all of the general partnership interests in SMLP. Such a change of control transaction constitutes an event of default under our revolving credit facility. Additionally, upon the occurrence of specific kinds of change of control events, the indentures governing our outstanding senior notes will require us to make an offer to repurchase all such notes at 101% of the principal amount thereof, plus accrued and unpaid interest to the date of repurchase, which event also constitutes an event of default under our revolving credit facility. As a result, if a change of control transaction is consummated, we will need to obtain the prior approval of the banks that are party to our revolving credit facility and we cannot predict whether we will be successful in obtaining such consent. If we cannot obtain such consent on acceptable terms, the consummation of a change of control transaction would constitute an event of default under the revolving credit facility unless it is refinanced in connection with such change of control transaction. We also cannot predict whether the banks party to our revolving credit facility would require material changes to the terms of our revolving credit facility in connection with granting their consent to a change of control transaction or how any such changes would affect our business and operations. If we must pay significant fees or increased expenses in connection with obtaining a consent or as a result of any such changes in the terms of our revolving credit facility, our business and results of operations may be adversely affected. In addition, if we must refinance our revolving credit facility, we may incur costs or pay increased interest or incur other increased expenses in the future, which could materially and adversely affect our business and results of operations.

Item 6. Exhibits.

Exhibit number		Description
3.1		First Amended and Restated Agreement of Limited Partnership of Summit Midstream Partners, LP, dated as of October 3, 2012 (Incorporated herein by reference to Exhibit 3.1 to SMLP's Current Report on Form 8-K dated October 4, 2012 (Commission File No. 001-35666))
3.2		Amended and Restated Limited Liability Company Agreement of Summit Midstream GP, LLC, dated as of October 3, 2012 (Incorporated herein by reference to Exhibit 3.2 to SMLP's Current Report on Form 8-K dated October 4, 2012 (Commission File No. 001-35666))
3.3		Certificate of Limited Partnership of Summit Midstream Partners, LP (Incorporated herein by reference to Exhibit 3.1 to SMLP's Form S-1 Registration Statement dated August 21, 2012 (Commission File No. 333-183466))
3.4		Certificate of Formation of Summit Midstream GP, LLC (Incorporated herein by reference to Exhibit 3.4 to SMLP's Form S-1 Registration Statement dated August 21, 2012 (Commission File No. 333-183466))
10.1		Second Amended and Restated Employment Agreement, dated July 20, 2015, and effective August 13, 2015, by and between Summit Midstream Partners, LLC and Steve Newby (Incorporated herein by reference to Exhibit 10.1 to SMLP's Form 8-K dated July 24, 2015 (Commission File No. 001-35666))
31.1		Rule 13a-14(a)/15d-14(a) Certification, executed by Steven J. Newby, President, Chief Executive Officer and Director
31.2		Rule 13a-14(a)/15d-14(a) Certification, executed by Matthew S. Harrison, Executive Vice President and Chief Financial Officer
32.1		Certifications required by Rule 13a-14(b) or Rule 15d-14(b) and Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350), executed by Steven J. Newby, President, Chief Executive Officer and Director, and Matthew S. Harrison, Executive Vice President and Chief Financial Officer
101.INS	**	XBRL Instance Document (1)
101.SCH	**	XBRL Taxonomy Extension Schema
101.CAL	**	XBRL Taxonomy Extension Calculation Linkbase

101.DEF	**	XBRL Taxonomy Extension Definition Linkbase
101.LAB	**	XBRL Taxonomy Extension Label Linkbase
101.PRE	**	XBRL Taxonomy Extension Presentation Linkbase

** 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

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amended, and otherwise are not subject to liability under those sections. The financial information contained in the XBRL (eXtensible Business Reporting Language)-related documents is unaudited and unreviewed.

(1) Includes the following materials contained in this Quarterly Report on Form 10-Q for the quarter ended September 30, 2015, formatted in XBRL: (i) Unaudited Condensed Consolidated Balance Sheets, (ii) Unaudited Condensed Consolidated Statements of Operations, (iii) Unaudited Condensed Consolidated Statements of Partners' Capital, (iv) Unaudited Condensed Consolidated Statements of Cash Flows, and (v) Notes to Unaudited Condensed Consolidated Financial Statements.

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SIGNATURES

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

Summit Midstream Partners, LP
(Registrant)

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

November 9, 2015

/s/ Matthew S. Harrison
Matthew S. Harrison, Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)