Rice Midstream Partners LP
Form 10-K
February 15, 2018
UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K
(Mark One)
þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Fiscal Year Ended December 31, 2017
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: 001-36789
Rice Midstream Partners LP
(Exact name of registrant as specified in its charter)

Delaware	47-1557755
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
625 Liberty Avenue, Suite 1700 Pittsburgh, Pennsylvania	15222
(Address of principal executive offices)	(Zip code)

Registrant's telephone number, including area code: (412) 553-5700

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

Title of each class	Name of each exchange on which registered
Common Units Representing Limited Partner Interests	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. þYes ¨No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. ¨Yes þNo

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. þYes ¨No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, 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). þYes ¨No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. þ

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a small reporting company or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer þ	Accelerated filer ¨
Non-accelerated filer ¨	Smaller reporting company ¨
(Do not check if a smaller reporting company)	Emerging growth company ¨

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). ¨Yes þNo

The aggregate market value of the common units held by non-affiliates of the registrant as of June 30, 2017: $1.5 billion

At January 31, 2018, there were 102,303,108 units (consisting of 73,549,485 common units and 28,753,623 subordinated units) outstanding.

Documents Incorporated by Reference
None

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Cautionary Statements

Disclosures in this Annual Report on Form 10-K contain certain forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934, as amended, and Section 27A of the Securities Act of 1933, as amended. Statements that do not relate strictly to historical or current facts are forward-looking and usually identified by the use of words such as “anticipate,” “estimate,” “could,” “would,” “will,” “may,” “forecast,” “approximate,” “expect,” “pr “intend,” “plan,” “believe” and other words of similar meaning in connection with any discussion of future operating or financial matters. Without limiting the generality of the foregoing, forward-looking statements contained in this Annual Report on Form 10-K include the matters discussed in the sections captioned Item 1, “Business” and “Outlook” in Item 7, “Management's Discussion and Analysis of Financial Condition and Results of Operations,” and the expectations of plans, strategies, objectives, and growth and anticipated financial and operational performance of us and its subsidiaries, including guidance regarding our gathering and water services revenue and volume growth; infrastructure programs (including the timing, cost, capacity and sources of funding with respect to gathering and water services expansion projects); natural gas production growth in our operating areas for EQT and third parties; the timing of EQT’s announcement of a decision for addressing its sum-of-the-parts discount; the amount and timing of distributions, including expected increases; the amounts and timing of projected operating and capital expenditures; the impact of commodity prices on our businesses; liquidity and financing requirements, including sources and availability; the effects of government regulation and litigation; and tax position. The forward-looking statements included in this Annual Report on Form 10-K involve risks and uncertainties that could cause actual results to differ materially from projected results. Accordingly, investors should not place undue reliance on forward-looking statements as a prediction of actual results. We have based these forward-looking statements on current expectations and assumptions about future events. While we consider these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks and uncertainties, many of which are difficult to predict and are beyond our control. The risks and uncertainties that may affect the operations, performance and results of our businesses and forward-looking statements include, but are not limited to, those set forth under “Item 1A. Risk Factors” and elsewhere in this Annual Report on Form 10-K.

Any forward-looking statement speaks only as of the date on which such statement is made and we do not intend to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise.

In reviewing any agreements incorporated by reference in or filed with this Annual Report on Form 10-K, please remember that such agreements are included to provide information regarding the terms of such agreements and are not intended to provide any other factual or disclosure information about us. The agreements may contain representations and warranties by us, which should not in all instances be treated as categorical statements of fact, but rather as a way of allocating the risk to one of the parties to such agreements should those statements prove to be inaccurate. The representations and warranties were made only as of the date of the relevant agreement or such other date or dates as may be specified in such agreement and are subject to more recent developments. Accordingly, these representations and warranties alone may not describe the actual state of affairs of us or our affiliates as of the date they were made or at any other time.

Commonly Used Defined Terms

As used in the Annual Report on Form 10-K, unless the context indicates or otherwise requires, the following terms have the following meanings:

- "Combined Year" refers to the combined periods from January 1, 2017 to November 12, 2017 and from November 13, 2017 to December 31, 2017.
- "EQT" refers to EQT Corporation, which effective November 13, 2017 indirectly owns the general partner interest, a limited partner interest and all of the incentive distribution rights in the Partnership, and its consolidated subsidiaries;
- "GP Holdings" refers to Rice Midstream GP Holdings LP, a wholly-owned subsidiary of EQT;
- "our general partner" or "Midstream Management" refers to Rice Midstream Management LLC, a wholly-owned subsidiary of EQT;
- "Rice Energy" refers to Rice Energy Inc., which indirectly owned the Partnership for the periods prior to November 13, 2017, and its consolidated subsidiaries;
- "RMP," "Partnership," "we," "our," "us" or like terms refers to Rice Midstream Partners LP and its consolidated subsidiaries;
- "Vantage Midstream Asset Acquisition" refers to the Partnership's acquisition from Rice Energy of the Vantage Midstream Entities;
- "Vantage Midstream Entities" refers collectively to Vantage Energy II Access, LLC and Vista Gathering, LLC, each of which is a wholly-owned subsidiary of the Partnership;
- "Appalachian Basin" refers to the area of the United States composed of those portions of West Virginia, Pennsylvania, Ohio, Maryland, Kentucky and Virginia that lie in the Appalachian Mountains; and
- "Disclosure Document" means EQT's 2018 Proxy Statement or amendments to its Annual Report on Form 10-K for the year ended December 31, 2017, as applicable, in each case as filed with the Securities and Exchange Commission (SEC).

PART I

Item 1. Business

Overview

We are a growth-oriented limited partnership formed by Rice Energy to own, operate, develop and acquire midstream assets in the Appalachian Basin. We operate in two business segments, which are managed separately due to their distinct operational differences: (i) gathering and compression and (ii) water services. Our natural gas gathering assets consist of natural gas gathering systems and associated compression that service EQT and other third-party producers in the dry gas core of the Marcellus Shale in southwestern Pennsylvania. Our water services assets consist of water pipelines, impoundment facilities, pumping stations, take point facilities and measurement facilities, which are used to support well completion activities and to collect and recycle or dispose of flowback and produced water for EQT and other third-party producers in Washington and Greene Counties, Pennsylvania and Belmont County, Ohio. We provide our services under long-term, fee-based contracts, primarily to EQT and its affiliates. Our principal business objective is to increase the quarterly cash distributions that we pay to our unitholders over time while ensuring the ongoing stability of our business.

On November 13, 2017 (the Merger Date), EQT and Rice Energy consummated the transactions contemplated by the Agreement and Plan of Merger, dated as of June 19, 2017 (as amended, the Merger Agreement), by and among EQT, Rice Energy and a wholly-owned subsidiary of EQT (Merger Sub). Pursuant to the Merger Agreement, Merger Sub merged with and into Rice Energy, with Rice Energy continuing as the surviving entity and an indirect, wholly-owned subsidiary of EQT. Immediately thereafter Rice Energy merged with and into another indirect, wholly-owned subsidiary of EQT (together, the Mergers).

Prior to the completion of the Mergers, Rice Energy was the indirect parent of our general partner and an indirect limited partner of us. Immediately following the completion of the Mergers, EQT became the indirect parent of our general partner and an indirect limited partner of us, acquiring beneficial ownership of 3,623 common units representing limited partner interests, 28,753,623 subordinated units representing limited partner interests and all of our incentive distribution rights (IDRs), which entitle EQT to receive 50% of all incremental cash distributed in a quarter after $0.2813 has been distributed in respect of each common unit of RMP for that quarter. The subordinated units converted into common units on a one-for-one basis on February 15, 2018.

Our Assets

Gathering and Compression Segment

Our gathering and compression assets are concentrated in the dry gas core of the Marcellus Shale and, as of December 31, 2017, consisted of a high-pressure dry gas gathering system and associated compression in Washington and Greene Counties, Pennsylvania, with connections to the Dominion Transmission, Columbia Gas Transmission, Texas Eastern Transmission, Equitrans Transmission and National Fuel Gas Supply interstate pipelines. The dry gas core of the Marcellus Shale in southwestern Pennsylvania is characterized by a combination of low development costs, consistently high production volumes and access to multiple takeaway pipelines. For the three months ended December 31, 2017, our average daily throughput was 1,539 BBtu/d. As of December 31, 2017, our gathering assets consisted of 178 miles of pipeline with gathering capacity of 5.1 TBtu/d and compression capacity of approximately 85,000 horsepower.

We contract with EQT and other producers to gather and compress natural gas from wells and well pads located in our dedicated areas and/or near our gathering systems. The natural gas we gather and compress generally requires no processing or treating prior to delivery into interstate pipelines.

We generate all of our gathering and compression revenues pursuant to long-term, fixed price per unit contracts. We generate revenue primarily by charging a fixed price per unit for volumes of natural gas that we gather and compress through our systems. Our assets are sized to accommodate the projected future production growth of EQT, as well as to allow us to pursue volumes from additional third parties. We have secured dedications from certain EQT affiliates under various fixed price per unit gathering and compression agreements covering (i) approximately 246,000 gross acres of EQT’s acreage position as of December 31, 2017 in Washington and Greene Counties, Pennsylvania, and (ii) subject to certain exceptions and limitations pursuant to the gathering and compression agreements, any future acreage certain affiliates of EQT acquire within these counties.

Following the completion of the Mergers, EQT became our largest customer, representing substantially all of our gathering and compression volumes for the year ended December 31, 2017 when considering the combined volumes of EQT and Rice Energy.

Water Services Segment

Our water services assets consist of water pipelines, impoundment facilities, pumping stations, take point facilities and measurement facilities, which are used to support well completion activities and to collect and recycle or dispose of flowback and produced water for EQT and other third parties in Washington and Greene Counties, Pennsylvania, and Belmont County, Ohio. We have the exclusive right to provide certain fluid handling services to EQT until December 22, 2029, and from month to month thereafter. The fluid handling services include the exclusive right to provide fresh water for well completions operations and to collect and recycle or dispose of flowback and produced water for EQT within certain areas of dedication in defined service areas in Washington and Greene Counties, Pennsylvania and Belmont County, Ohio. We also provide water services to third parties under fee-based contracts to support well completion activities. As of December 31, 2017, our Pennsylvania assets provided access to 29.4 MMgal/d of fresh water from the Monongahela River and several other regional water sources, while our Ohio assets provided access to 14.0 MMgal/d of fresh water from the Ohio River and several other regional water sources, both for distribution to EQT and third parties.

Following the completion of the Mergers, EQT became our largest customer, representing approximately 91% of our water services volumes for the year ended December 31, 2017 when considering the combined volumes of EQT and Rice Energy.

Please see Note 10 to the Consolidated Financial Statements included in this Annual Report for additional information about our segments.

2018 Capital Budget

In 2018, we plan to invest $260 million on organic projects, of which $215 million is expected to be used for our continued build-out of our Pennsylvania gas gathering systems and $45 million is expected to be used for our water services infrastructure.

Our Customers

EQT (inclusive of the results of Rice Energy prior to the Mergers) represented substantially all of our gathering and compression revenues and 96% of our water revenues for the year ended December 31, 2017.

Our Relationship with EQT

EQT is an integrated energy company, with an emphasis on natural gas production, gathering and transmission. EQT conducts its business through five business segments: EQT Production, EQM Gathering, EQM Transmission, RMP Gathering and RMP Water. EQT Production holds 21.4 Tcfe of proved natural gas, NGLs and crude oil reserves across approximately 4.0 million gross acres, including approximately 1.1 million gross acres in the Marcellus play, many of which have associated deep Utica and/or Upper Devonian drilling rights, and approximately 0.1 million gross acres in the Ohio Utica play as of December 31, 2017. EQM Gathering and EQM Transmission provide gathering, transmission and storage services for EQT's produced gas, as well as for independent third parties across the Appalachian Basin through EQT Midstream Partners, LP (EQM).

Following the completion of the Mergers, EQT became the indirect parent of our general partner, which owned the non-economic general partner interest in us, and acquired beneficial ownership of a 28.1% limited partner interest in us and all of our IDRs. In addition, as of December 31, 2017, EQT indirectly held a 90.1% limited partner interest and 100% of the non-economic general partner interest in EQT GP Holdings, LP (EQGP), which owned a 1.8% general partner interest in EQM, all of the IDRs in EQM and a 26.6% limited partner interest in EQM.

Our relationship with EQT is also a source of potential conflicts. For example, EQT is not restricted from competing with us, whether directly, through EQM or otherwise. In addition, all of the executive officers and six of the directors of our general partner also serve as officers and/or directors of EQT, three of the executive officers and four of the directors of our general partner also serve as officers and/or directors of EQT GP Services, LLC, the general partner of EQGP, and all of the executive officers and five of the directors of our general partner also serve as officers and/or directors of EQT Midstream Services, LLC, the general partner of EQM. These individuals face conflicts of interest, which include the allocation of their time among us, EQT, EQGP and EQM. For a description of our relationships with EQT, please read “Item 13. Certain Relationships and Related Transactions and Director Independence.” In addition, EQT has announced that its board of directors has formed a committee to evaluate options for addressing EQT’s sum-of-the-parts discount. EQT’s board will announce a decision by the end of March 2018, after considering the committee’s recommendation.

Title to Properties and Rights-of-Way
Our real property is classified into two categories: (i) parcels that we own in fee and (ii) parcels in which our interest derives from leases, easements, right-of-ways, permits or licenses from landowners or government authorities, permitting the use of such land for our operations. Portions of the land on which our pipelines and major facilities are located are owned by us in fee title, and we believe that we have satisfactory title to these lands. The remainder of the land on which our pipelines and major facilities are located are held by us pursuant to surface leases between us, as lessee, and the fee owner of the lands, as lessors. We have leased or owned these lands without any material challenge known to us relating to the title to the land upon which the assets are located, and we believe that we have satisfactory leasehold estates or fee ownership of such lands. We have no knowledge of any challenge to the underlying fee title of any material lease, easement, right-of-way, permit or license held by us or to our title to any material lease, easement, right-of-way, permit or lease, and we believe that we have satisfactory title to all of its material leases, easements, rights-of-way, permits and licenses.

Some of the leases, easements, rights-of-way, permits and licenses that were transferred to us from Rice Energy required the consent of the grantor of such rights, which in certain instances is a governmental entity. Rice Energy obtained sufficient third-party consents, permits and authorizations for the transfer of the assets necessary to enable us to operate our business in all material respects. With respect to any remaining consents, permits or authorizations that have not been obtained, we have determined these will not have a material adverse effect on the operation of our business should we fail to obtain such consents, permits or authorization in a reasonable time frame.
Seasonality
Demand for natural gas generally decreases during the spring and fall months and increases during the summer and winter months. However, seasonal anomalies such as mild winters or mild summers sometimes lessen this fluctuation. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations. These seasonal anomalies can increase demand for our services during the summer and winter months and decrease demand for our services during the spring and fall months.
Competition
Key competitors for new gathering systems include companies that own major natural gas pipelines, independent gas gatherers and integrated energy companies. Many of our competitors, including EQM, have capital resources and control supplies of natural gas greater than we do. Key competition for water services include natural gas producers that develop their own water distribution systems in lieu of employing our assets and other natural gas midstream companies. Our ability to attract volumes to the water services business depends on our ability to evaluate and select suitable projects and to consummate transactions in a highly competitive environment.
Regulation of Operations
Regulation of pipeline gathering services may affect certain aspects of our business and the market for our services. Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated by agencies of the U.S. federal government, primarily the Federal Energy Regulatory Commission (FERC). FERC regulates interstate natural gas transportation rates and service conditions, which affects the marketing of natural gas that EQT produces, as well as the revenues EQT receives for sales of its natural gas.
The transportation and sale for resale of natural gas in interstate commerce is regulated primarily under the Natural Gas Act (NGA) and by regulations and orders promulgated under the NGA by FERC. In certain limited circumstances, intrastate transportation, gathering, and wholesale sales of natural gas may also be affected directly or indirectly by laws enacted by Congress and by FERC regulations.
Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. Although its policy is still in flux, FERC has reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase EQT's costs of getting gas to point of sale locations. State regulation of natural gas gathering facilities generally include various safety, environmental and, in some circumstances, nondiscriminatory-take requirements. Although such regulation has not generally been affirmatively applied by state agencies, states are currently pursuing regulatory programs intended to safely build pipeline infrastructure. For instance, the Pennsylvania Pipeline Infrastructure Task Force is currently

developing policies and guidelines to assist in pipeline development to, among other goals, ensure pipeline safety and integrity during operation of the pipeline.

Intrastate natural gas transportation is also subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as our assets are determined to be intrastate transportation facilities, such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, and we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis would not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that EQT produces, as well as the revenues EQT receives for sales of its natural gas.

Changes in law and to FERC policies and regulations may adversely affect the availability and reliability of firm and/or interruptible transportation service on interstate pipelines, and we cannot predict what future action FERC will take. We do not believe, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other natural gas gatherers with which we compete.

FERC is authorized to impose civil penalties of up to approximately $1.2 million per violation, per day for violations of the NGA, the Natural Gas Policy Act (NGPA) or the rules, regulations, restrictions, conditions and orders promulgated under those statutes. This maximum penalty authority established by statute will continue to be adjusted periodically for inflation. The civil penalty provisions are applicable to entities that engage in the transportation and sale of natural gas for resale in interstate commerce.

The Energy Policy Act of 2005 (EPAct 2005) amended the NGA to add an anti-market manipulation provision which makes it unlawful for any entity to engage in prohibited behavior as prescribed by FERC. In Order No. 670, the FERC promulgated rules implementing the anti-market manipulation provision of EPAct 2005. The rules make it unlawful in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, (1) to use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) to engage in any act or practice that operates as a fraud or deceit upon any person. The anti-market manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of gas pipelines and storage companies that provide interstate services, as well as otherwise non-jurisdictional entities to the extent the activities are conducted “in connection with” gas sales, purchases or transportation subject to FERC jurisdiction.

Gathering Pipeline Regulation

Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by the FERC as a natural gas company under the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional tests the FERC has used to establish whether a pipeline is a gathering pipeline not subject to FERC jurisdiction as a natural gas company. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is often the subject of litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by the FERC, the courts, or Congress. If the FERC were to consider the status of an individual facility and determine that the facility and/or services provided by it are not exempt from FERC regulation, the rates for, and terms and conditions of, services provided by such facility would be subject to regulation by the FERC. Such regulation could decrease revenue, increase operating costs, and, depending upon the facility in question, could adversely affect our results of operations and cash flows. In addition, if any of our facilities were found to have provided services or otherwise operated in violation of the NGA or the NGPA, this could result in the imposition of civil penalties as well as a requirement to disgorge charges collected for such service in excess of the cost-based rate established by the FERC.

While our systems have not been regulated by FERC as a natural gas company under the NGA, we are required to report aggregate volumes of natural gas purchased or sold at wholesale to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. In addition, Congress may enact legislation or FERC may adopt regulations that may subject certain of our otherwise non-FERC jurisdictional facilities to further regulation. Failure to comply with those regulations in the future could subject us to civil penalty liability.

State regulation of natural gas gathering facilities and intrastate transportation pipelines generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and complaint-based rate regulation. Our natural gas gathering facilities are not subject to rate regulation or open access requirements in the states in which we operate. However, state regulators may require us to register as pipeline operators, pay assessment and registration fees, undergo inspections, and report annually on the miles of pipeline we operate. We cannot predict what new or different regulations federal and state regulatory agencies may adopt, or what effect subsequent regulation may have on our activities. Such regulations may have a material adverse effect on our financial condition, result of operations and cash flows.

Pipeline Safety Regulation

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Some of our pipelines are subject to regulation by the Pipeline and Hazardous Materials Safety Administration (PHMSA), pursuant to the Natural Gas Pipeline Safety Act of 1968 (NGPSA), and the Pipeline Safety Improvement Act of 2002 (PSIA), as reauthorized and amended by the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (2006 PIPES Act). The NGPSA regulates safety requirements in the design, construction, operation and maintenance of gas pipeline facilities, while the PSIA establishes mandatory inspections for all U.S. oil and natural gas transmission pipelines in high-consequence areas (HCAs).

The PHMSA has developed regulations that require pipeline operators to implement integrity management programs, including more frequent inspections and other measures to ensure pipeline safety in HCAs. The regulations require operators, including us, to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact an HCA;
- improve data collection, integration and analysis;
- repair and remediate pipelines as necessary; and
- implement preventive and mitigating actions.

The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (2011 Pipeline Safety Act) reauthorizes funding for federal pipeline safety programs, increases penalties for safety violations, establishes additional safety requirements for newly constructed pipelines, and requires studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines. The 2011 Pipeline Safety Act, among other things, increases the maximum civil penalty for pipeline safety violations and directs the Secretary of Transportation to promulgate rules or standards relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation and testing to confirm the material strength of pipe operating above 30% of specified minimum yield strength in HCAs. PHMSA has the authority to impose civil penalties for pipeline safety violations up to a maximum of approximately $200,000 per day for each violation and approximately $2 million for a related series of violations. This maximum penalty authority established by statute will continue to be adjusted periodically to account for inflation. The safety enhancement requirements and other provisions of the 2011 Pipeline Safety Act as well as any implementation of PHMSA regulations thereunder or any issuance or reinterpretation of PHMSA guidance with respect thereto could require us to install new or modified safety controls, pursue additional capital projects or conduct maintenance programs on an accelerated basis, any of which could result in our incurring increased operating costs that could have a material adverse effect on our results of operations or financial position.

PHMSA regularly revises its pipeline safety regulations. For example, in March of 2015, PHMSA finalized new rules applicable to gas and hazardous liquid pipelines that, among other changes, impose new post-construction inspections, welding, gas component pressure testing requirements, as well as requirements for calculating pressure reductions for immediate repairs on liquid pipelines. Additionally, in April 2016, PHMSA proposed rules that would, if adopted, impose more stringent requirements for certain gas lines. Among other things, the proposed rulemaking would extend certain of PHMSA's current regulatory safety programs for gas pipelines beyond HCAs to cover gas pipelines found in newly defined "moderate consequence areas" that contain as few as five dwellings within the potential impact area and would also require gas pipelines installed before 1970 that are currently exempted from certain pressure testing obligations to be tested to determine their maximum allowable operating pressures (MAOP). Other new requirements proposed by PHMSA under the rulemaking would require pipeline operators to: report to PHMSA in the event of certain MAOP exceedances; strengthen PHMSA integrity management requirements; consider seismicity in evaluating threats to a pipeline; conduct hydrostatic testing for all pipeline segments manufactured using longitudinal seam welds; and use more detailed guidance from PHMSA in the selection of assessment methods to inspect pipelines. The proposed rulemaking also seeks to impose a number of requirements on gathering lines. Additionally, in January 2017, PHMSA promulgated a new final rule regarding hazardous liquid pipelines, which increases the quality and frequency of tests that assess the condition of pipelines, requires operators to annually evaluate the existing protective measures in place for pipeline segments in HCAs, extends certain leak detection requirements for hazardous liquid pipelines not located in HCAs, and expands the list of conditions that require immediate repair. However, it is unclear when or if this rule will go into effect because, on January 20, 2017, the Trump Administration requested that all regulations that had been sent to the Office of the Federal Register, but were not yet published, be immediately withdrawn for further review. Accordingly, this rule has not become effective through publication in the Federal Register. We are monitoring and evaluating the effect of these and other emerging requirements on our operations.

States are largely preempted by federal law from regulating pipeline safety for interstate lines but most are certified by the U.S. Department of Transportation (DOT) to assume responsibility for enforcing federal intrastate pipeline regulations and inspection of intrastate pipelines. In June 2016, President Obama signed into law new legislation entitled Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016 (2016 Pipeline Safety Act). The 2016 Pipeline Safety Act reauthorizes PHMSA through 2019, and facilitates greater pipeline safety by providing PHMSA with emergency order authority, including authority to issue prohibitions and safety measures on owners and operators of gas or hazardous liquid pipeline facilities to address imminent hazards, without prior notice or an opportunity for a hearing, as well as enhanced release reporting requirements, requiring a review of both natural gas and hazardous liquid integrity management programs, and mandating the creation of a working group to consider the development of an information-sharing system related to integrity risk analyses. Pursuant to those provisions of the 2016 Pipeline Safety Act, in October 2016 and December 2016, PHMSA issued two separate Interim Final Rules that expanded the agency's authority to impose emergency restrictions, prohibitions and safety measures and strengthened the rules related to underground natural gas storage facilities, including well integrity, wellbore tubing and casing integrity. The December 2016 Interim Final Rule, relating to underground gas storage facilities, went into effect in January 2017, with a compliance deadline in January 2018. PHMSA determined, however, that it will not issue enforcement citations to any operators for violations of provisions of the December 2016 Interim Final Rule that had previously been non-mandatory provisions of American Petroleum Institute Recommended Practices 1170 and 1171 until one year after PHMSA issues a final rule. In October 2017, PHMSA formally reopened the comment period on the December 2016 Interim Final Rule in response to a petition for reconsideration, with comments due in November 2017.

Regulation of Environmental and Occupational Safety and Health Matters

General

Our natural gas gathering and water services activities are subject to stringent and complex federal, state and local laws and regulations relating to the protection of the environment. As an owner or operator of these facilities, we must comply with these laws and regulations at the federal, state and local levels. These laws and regulations can restrict or impact our business activities in many ways, such as:

- requiring the installation of pollution-control equipment, imposing emission or discharge limits or otherwise restricting the way we operate resulting in additional costs to our operations;
- limiting or prohibiting construction activities in areas, such as air quality nonattainment areas, wetlands, coastal regions, endangered species habitat and other protected areas;
- delaying system modification or upgrades during review of permit applications and revisions;
- requiring investigatory and remedial actions to mitigate discharges, releases or pollution conditions associated with our operations or attributable to former operations; and
- enjoining operations deemed to be in non-compliance with permits issued pursuant to, or regulatory requirements imposed by, such environmental laws and regulations.

Failure to comply with these laws and regulations could result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties and damages. Certain environmental statutes impose strict joint and several liability for costs required to clean up and restore sites where hazardous substances, hydrocarbons or solid wastes have been disposed or otherwise released. Moreover, neighboring landowners and other third parties may file common law claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other pollutants into the environment.

The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment and thus, there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation and actual future expenditures may be different from the amounts we currently anticipate. As with the midstream industry in general, complying with current and anticipated environmental laws and regulations can increase our costs to construct, maintain and operate equipment and facilities. While these laws and regulations affect our capital expenditures and net income, we do not believe they will have a material adverse effect on our business, financial position or results of operations or cash flows, nor do we believe that they will affect our competitive position since the operations of our competitors are generally similarly affected. In addition, we do not believe that the various activities in which we are presently engaged that are subject to environmental laws and regulations will materially interrupt or diminish our operational ability to gather natural gas or obtain and deliver water. We cannot assure you, however, that future events, such as changes in existing laws or enforcement policies, the promulgation of new laws or regulations, or the development or discovery of new facts or conditions will not cause us to incur significant costs. Below is a discussion of the material environmental laws and regulations that relate to our business.

Hydraulic Fracturing Activities

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Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. Hydraulic fracturing involves the injection of water, sand or alternative proppant and chemicals under pressure into target geological formations to fracture the surrounding rock and stimulate production. Our anchor customer, EQT, regularly uses hydraulic fracturing as part of its operations. Hydraulic fracturing is typically regulated by state oil and natural gas commissions, but, in response to increased public concern regarding the alleged potential impacts of hydraulic fracturing, the U.S. Environmental Protection Agency (EPA) has asserted federal regulatory authority pursuant to the federal Safe Drinking Water Act (SDWA) over certain hydraulic fracturing activities involving the use of diesel fuels and published permitting guidance in February 2014 addressing the performance of such activities using diesel fuels. The EPA has also issued final regulations under the federal Clean Air Act (CAA) establishing performance standards, including standards for the capture of air emissions released during hydraulic fracturing, published a notice of proposed rulemaking under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing, and finalized rules in June 2016 that prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. The EPA announced its intention to reconsider the CAA performance standards rule in April 2017 and has sought to stay its requirements; however, the rule remains in effect. These rules, if not changed or withdrawn, will continue to require changes to our operations, including the installation of new equipment to control emissions. In addition, the Bureau of Land Management (BLM) finalized rules in March 2015 that imposed new or more stringent standards for performing hydraulic fracturing on federal and American Indian lands. The BLM rule was struck down by a federal court in Wyoming in June 2016, but reinstated on appeal by the Tenth Circuit in September 2017. While this appeal was pending, the BLM proposed a rulemaking in July 2017 to rescind these rules in their entirety. Although the BLM published a final rule rescinding the 2015 rules in December 2017, other federal or state agencies may look to the BLM rule in developing new regulations that could apply to our operations.

Various state and federal agencies are studying the potential environmental impacts of hydraulic fracturing. In December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report, contrary to several previously published draft reports issued by the EPA, found instances in which impacts to drinking water may occur. However, the report also noted significant data gaps that prevented the EPA from determining the extent or severity of these impacts. The results of such reviews or studies could spur initiatives to further regulate hydraulic fracturing.

Presently, hydraulic fracturing is regulated primarily at the state level, typically by state oil and natural gas commissions and similar agencies. In July 2015, the Ohio Department of Natural Resources issued final rules for horizontal drilling well-pad construction. Ohio, Pennsylvania (where we conduct a majority of our operations), and Texas have all adopted laws and proposed regulations that require oil and natural gas operators to disclose chemical ingredients and water volumes used to hydraulically fracture wells, in addition to more stringent well construction and monitoring requirements. In addition, in January 2016, the Pennsylvania Department of Environmental Protection (PADEP) issued new rules establishing stricter disposal requirements for wastes associated with hydraulic fracturing activities, which include, among other things, a prohibition on the use of centralized impoundments for the storage of drill cuttings and waste fluids. Further, these rules include requirements relating to storage tank vandalism, secondary containment for storage vessels, construction rules for gathering lines and horizontal drilling under streams, and temporary transport lines for freshwater and wastewater. Moreover, local governments may also adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular or prohibit the performance of well drilling in general or hydraulic fracturing in particular. The adoption of new laws, regulations or ordinances at the federal, state or local levels imposing more stringent restrictions on hydraulic fracturing could make it more difficult for our customers to complete natural gas wells, increase our customers' costs of compliance and doing business, and otherwise adversely affect the hydraulic fracturing services they perform, which could negatively impact demand for our gathering, transmission, storage and water services.

If new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where our customers operate, our customers could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells. Any such added costs, delays or restrictions for our customers could significantly affect our operations. In addition, if the amount of water needed to hydraulically fracture wells is unavailable or if flowback water disposal options become more limited, our customers may experience added costs or delays, which could significantly affect our operations.

Hazardous Waste

The federal Resource Conservation and Recovery Act (RCRA), and comparable state laws, impose requirements for the handling, storage, treatment and disposal of nonhazardous and hazardous waste. RCRA currently exempts certain wastes associated with the exploration, development or production of crude oil and natural gas, which we handle in the course of our operations, including produced water. However, these oil and gas exploration and production wastes may still be regulated by the EPA or state agencies under RCRA's less stringent nonhazardous solid waste provisions or other federal laws, or state laws, and it is possible that certain oil and natural gas exploration and production wastes now classified as non-hazardous could be classified as hazardous waste in the future. For example, from time to time certain environmental groups have petitioned or sued the EPA to remove the RCRA's exemption for wastes associated with the exploration, development or production of crude oil and natural gas. For example, in December 2016, the EPA and environmental groups entered into a consent decree to address EPA's alleged failure to timely assess its RCRA Subtitle D criteria regulations exempting certain exploration and production related oil and gas wastes from regulation as hazardous wastes under RCRA. The consent decree requires the EPA to propose a rulemaking no later than March 15, 2019 for revision of certain Subtitle D criteria regulations pertaining to oil and gas wastes or to sign a determination that revision of the regulations is not necessary. If such changes were to occur, it could have a significant impact on our operating costs, as well as the natural gas and oil industry in general. Moreover, some ordinary industrial wastes which we generate, such as paint wastes, waste solvents, laboratory wastes and waste oils, may be regulated as hazardous wastes if they have hazardous characteristics.

Site Remediation

We currently own, lease or operate, and may have in the past owned, leased or operated, properties that have been used for the gathering of natural gas. Although we typically used operating and disposal practices that were standard in the industry at the time, petroleum hydrocarbons or wastes may have been disposed of or released on or under the properties owned or leased by us or on or under other locations where such substances have been taken for disposal. Such petroleum hydrocarbons or wastes may have migrated to property adjacent to our owned and leased sites or the disposal sites. In addition, some of the properties may have been operated by third parties or by previous owners whose treatment and disposal or release of petroleum hydrocarbons or wastes was not under our control.

The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), also known as the Superfund law, and comparable state laws impose liability without regard to fault or the legality of the original conduct, on certain classes of persons responsible for the release of hazardous substances into the environment. Under CERCLA, such classes of persons include the current and past owners or operators of sites where a hazardous substance was released, and companies that disposed or arranged for disposal of hazardous substances at offsite locations, such as landfills. CERCLA authorizes the EPA, states, and, in some cases, third parties to take actions in response to releases or threatened releases of hazardous substances into the environment and to seek to recover from the classes of responsible persons the costs they incur to address the release. Under CERCLA, we could be subject to strict joint and several liability for the costs of cleaning up and restoring sites where hazardous substances have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. In some states, including Pennsylvania, site remediation of oil and natural gas facilities is regulated by state agencies with jurisdiction over oil and natural gas operations. The regulated releases and remediation activities, including the classes of persons that may be held responsible for releases of hazardous substances, may be broader than those regulated under CERCLA or RCRA.

Although natural gas is excluded from CERCLA's definition of "hazardous substance," in the course of our ordinary operations we may handle substances or wastes designated as hazardous. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove previously disposed wastes, including waste disposed of by prior owners or operators; remediate contaminated property, including groundwater contamination, whether from prior owners or operators or other historic activities or spills; or perform remedial operations to prevent future contamination. We are not currently a potentially responsible party in any federal or state Superfund site remediation and there are no current, pending or anticipated Superfund response or remedial activities at our facilities.

Air Emissions

The CAA, and comparable state laws, regulate emissions of air pollutants from various industrial sources, including natural gas processing plants and compressor stations, and also impose various preconstruction requirements, emission limits, operational limits and monitoring, reporting and recordkeeping requirements on air emission sources. Recently, in October 2015, the EPA lowered the National Ambient Air Quality Standard (NAAQS) for ozone from 75 to 70 parts per billion for both the 8-hour primary and secondary standards. State implementation of the revised NAAQS could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits, and result in increased expenditures for pollution control equipment, the costs of which could be significant. Failure to comply with these requirements could result in monetary penalties, injunctions, conditions or restrictions on operations, and/or criminal enforcement actions. Such laws and regulations, for example, require preconstruction permits, such as Prevention of Significant Deterioration, or PSD permits, for the construction or modification of certain projects or facilities with the potential to emit air pollutants above certain thresholds. Preconstruction permits generally require use of best available control technology (BACT) to limit air emissions. Several federal and state new source performance standards and national emission standards for hazardous air pollutants and analogous state law requirements also apply to our facilities and operations. These applicable federal and state standards impose emission limits and operational limits as well as detailed testing, recordkeeping and reporting requirements on the facilities subject to these regulations. Several of our facilities are “major” facilities requiring Title V operating permits which impose semi-annual reporting requirements, but the number of such facilities could grow in the future. For example, in June 2016, the EPA finalized rules under the CAA regarding criteria for aggregating multiple sites into a single source for air-quality permitting purposes applicable to the oil and gas industry. This rule could cause small facilities (such as tank batteries and compressor stations), on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting requirements, which in turn could result in operational delays or require us to install costly pollution control equipment. Also, in December 2016, the PADEP announced that the agency intends to issue a new general permit for oil and gas exploration, development, and production facilities and liquids loading activities, requiring best available technology for equipment and processes, enhanced record-keeping, and quarterly monitoring inspections for the control of methane emissions. The PADEP issued “draft-final” language for methane reductions from the oil and gas section in November 2017, and intends to issue similar methane rules for existing sources. The PADEP also proposed a new general permit for compressor stations that includes noise minimization requirements.

We may incur capital expenditures in the future for air pollution control equipment in connection with complying with existing and recently proposed rules, or with obtaining or maintaining operating or preconstruction permits and complying with federal, state and local regulations related to air emissions (including air emission reporting requirements). However, we do not believe that such requirements will have a material adverse effect on our operations and we believe such requirements will not be any more burdensome to us than to other similarly situated companies.

Water Discharges

The Federal Water Pollution Control Act, or the Clean Water Act (CWA), and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including sediment, and spills and releases of oil, brine and other substances into waters of the United States. The discharge of pollutants into jurisdictional waters or wetlands is prohibited except in accordance with the terms of a permit issued by the EPA, the U.S. Army Corps of Engineers or a delegated state agency. In September 2015, new EPA and U.S. Army Corps of Engineers rules defining the scope of the EPA’s and the U.S. Army Corps of Engineers’ jurisdiction became effective (2015 Clean Water Rule). To the extent the rule expands the scope of the CWA’s jurisdiction, we could face increased costs and delays with respect to obtaining permits for activities in wetland areas. The rule has been challenged in court on the grounds that it unlawfully expands the reach of CWA programs, and implementation of the rule has been stayed pending resolution of the court challenge. In November 2017, the EPA and the U.S. Army Corps of Engineers proposed the addition of an applicability date to the 2015 Clean Water Rule that would be two years after the date of a final rule. This change, if adopted, would effectively prevent the rule from coming back into effect immediately if the stay is lifted. The process for obtaining permits has the potential to delay our operations. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with permits or other requirements of the CWA and analogous state laws and regulations. We believe that we maintain all required discharge permits necessary to conduct our operations. Any unpermitted release of petroleum or other pollutants from our operations could result in government penalties and administrative, civil or criminal liability.

Occupational Safety and Health Act

We are subject to the requirements of the federal Occupational Safety and Health Act (OSHA). Specifically, OSHA’s hazard communication standard, the Emergency Planning and Community Right-to-Know Act and implementing regulations, and similar state statutes and regulations, require that information be maintained about hazardous materials used or produced in our operations and that this information be provided to state and local government authorities and citizens. Certain of our operations are also subject to OSHA Process Safety Management regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive material.

Endangered Species and Migratory Bird Treaty Act

The Endangered Species Act (ESA) and analogous state laws restrict activities that may affect endangered or threatened species or their habitats. Similar protections are offered to migratory birds under the Migratory Bird Treaty

Act. Some of our pipelines are located in areas that are or may be designated as protected habitats for endangered or threatened species, including the Indiana Bat, which has a seasonal impact on our construction activities and operations. The future listing of previously unprotected species in areas where we conduct or may conduct operations, or the designation of critical habitat in these areas, could cause us to incur increased costs arising from species protection measures or could result in limitations on our operating activities, which could have an adverse impact on our results of operations. For example, in April 2015, the U.S. Fish and Wildlife Service listed the northern long-eared bat, whose habitat includes the areas in which we operate, as a threatened species under the ESA. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and may materially delay or prohibit access to protected areas that lay within our areas of operation.

Climate Change

In December 2009, the EPA determined that emissions of greenhouse gases (GHGs) present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA adopted regulations under existing provisions of the CAA that establish pre-construction and operating permit requirements for GHG emissions from certain large stationary sources. Under these regulations, for example, facilities required to obtain Prevention of Significant Deterioration (PSD) permits because they are potential major sources of criteria pollutants must comply with BACT-driven GHG permit limits established by the states or, in some cases, by the EPA, on a case-by-case basis. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States, including, among others, certain onshore oil and natural gas processing and fractionating facilities, as well as gathering and boosting facilities. We are monitoring GHG emissions from our operations in accordance with the GHG emissions reporting rule. Also, in May 2016, the EPA finalized rules that impose volatile organic compound emissions limits (and collaterally reduce methane emissions) on certain types of compressors and pneumatic pumps, as well as requiring the development and implementation of leak monitoring plans for compressor stations. The EPA announced its intention to reconsider certain of these rules in April 2017 and has sought to stay their requirements; however, the rules remain in effect. These regulations, if not changed or withdrawn, will continue to require changes to our operations, including the installation of new equipment to control emissions. The EPA has also announced that it intends to pursue, but has not yet proposed, methane emission standards for existing sources in addition to new sources. Several states are also pursuing similar measures to regulate emissions of GHGs from new and existing sources. If enacted or promulgated, additional GHG regulations could impose new compliance costs and permitting burdens on our operations.

Also, in November 2016, the BLM finalized, and in December 2016 the PADEP announced that it intends to propose rules related to the control of methane emissions. Certain provisions of the BLM rule went into effect in January 2017, while others were scheduled to go into effect in January 2018. In December 2017, BLM published a final rule delaying the 2018 provisions until 2019. The final draft of the PADEP rule was released in November 2017, and the PADEP hopes to finalize the regulations in early 2018. Compliance with rules to control methane emissions will likely require enhanced record-keeping practices, the purchase of new equipment such as optical gas imaging instruments to detect leaks, and the increased frequency of maintenance and repair activities to address emissions leakage. The rules will also likely require hiring additional personnel to support these activities or the engagement of third party contractors to assist with and verify compliance. These new rules could result in increased compliance costs on our operations. The PADEP also recently announced an initiative to restrict methane emissions from natural gas development activities. Under the proposed changes, operators in Pennsylvania would need to (i) obtain an air quality general permit in advance of operations, (ii) control releases, and (iii) report emissions.

Additionally, while Congress has from time to time considered legislation to reduce emissions of GHGs, the prospect for adoption of significant legislation at the federal level to reduce GHG emissions is perceived to be low at this time. However, many states have adopted cap and trade programs or renewable energy portfolio standards in an effort to reduce GHG emissions, and these efforts are likely to continue absent additional federal action. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations that limit emissions of GHGs could adversely affect demand for the oil and natural gas that exploration and production operators produce, some of whom are our customers, which could thereby reduce demand for our midstream services. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events; if any such effects were to occur, it is uncertain if they would have an adverse effect on our business, financial condition, results of operations, liquidity or ability to make distributions to our unitholders.

Although we have not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue.

Employees

We do not have any employees. We are managed by the directors and officers of our general partner. All executive management personnel of our general partner are officers of EQT and devote the portion of their time to our business and affairs that is required to manage and conduct our operations. Our daily business operations are conducted by employees of EQT's operating subsidiaries. Under the terms of our omnibus agreement with EQT, we reimburse EQT for the provision of general and administrative services for our benefit, for direct expenses incurred by EQT on our behalf, for expenses allocated to us as a result of it being a public entity and for operation and management services provided by EQT's operating subsidiaries. Additionally, we have an employee secondment agreement with EQT whereby EQT and its subsidiaries provide seconded employees to perform certain operating and other services with respect to our business.

Insurance

We generally share insurance coverage with EQT. We reimburse EQT for the cost of the insurance pursuant to the terms of our omnibus agreement with EQT. The insurance program includes excess liability insurance, auto liability insurance, workers' compensation insurance and property insurance. In addition, we have procured separate general liability and directors and officers liability policies. All insurance coverage is in amounts management believes to be reasonable and appropriate.

Facilities

EQT's corporate headquarters are in Pittsburgh, Pennsylvania. Pursuant to our omnibus agreement with EQT, we reimburse EQT for our proportionate share of EQT's costs to lease the building.

Available Information

Our website is available at www.ricemidstream.com. Information contained on or connected to our website is not incorporated by reference into this Annual Report on Form 10-K and should not be considered part of this Annual Report on Form 10-K or any other filing we make with the SEC. We make available, free of charge, on our website, our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments and exhibits to those reports, as soon as reasonably practicable after filing such reports with the SEC. Other information such as our Corporate Governance Guidelines, the charter of our Audit Committee and our Code of Business Conduct and Ethics are available on our website and in print to any unitholder who provides a written request to our Corporate Secretary at 625 Liberty Avenue, Suite 1700, Pittsburgh. Pennsylvania 15222.

The public may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains a website that contains reports and information statements, and other information regarding issuers that file electronically with the SEC. The public can obtain any document that we file with the SEC at www.sec.gov.

Composition of Segment Operating Revenues

Presented below are operating revenues by segment as a percentage of our total operating revenues.

	Successor	Predecessor		
		Period from January 1, 2017 to November 12, 2017	Years Ended December 31,	
Operating revenues:	Period from November 13, 2017 to December 31, 2017		2016	2015
Gathering and compression	69 %	67 %	66 %	67 %
Water services	31 %	33 %	34 %	33 %

Financial Information about Segments

Please see Note 10 to the Consolidated Financial Statements in this Annual Report for financial information by business segment including, but not limited to, revenues from external customers, operating income and total assets, which information is incorporated herein by reference.

Jurisdiction and Year of Formation

Rice Midstream Partners LP is a Delaware limited partnership formed in August 2014.

Financial Information about Geographic Areas

All of our assets and operations are located in the continental United States.

Item 1A. Risk Factors

In addition to the other information contained in this Annual Report, the following risk factors should be considered in evaluating our business and future prospects. Please note that additional risks not presently known to us or that are currently

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considered immaterial may also have a negative impact on our business and operations. If any of the events or circumstances described below actually occurs, our business, financial condition, results of operations, liquidity or ability to make distributions to our unit holders could suffer and the trading price of our common units could decline. The risk factor information presented below reflects the impacts of the Mergers.

Risks Related to Our Business

Because a substantial majority of our revenue currently is, and over the long term is expected to be, derived from EQT, any development that materially and adversely affects EQT’s operations, financial condition or market reputation could have a material and adverse impact on us.

For the year ended December 31, 2017, EQT accounted for substantially all of our gas gathering and compression revenues and 96% of our water services revenues, inclusive of the results of Rice Energy for periods prior to the Mergers. We are substantially dependent on EQT as our most significant customer, and we expect to derive a substantial majority of our revenues from EQT for the foreseeable future. As a result, any event, whether in our dedicated areas or otherwise, that adversely affects EQT’s production and drilling schedule, financial condition, leverage, market reputation, liquidity, results of operations or cash flows may adversely affect our revenues and cash available for distribution. Accordingly, we are indirectly subject to the business risks of EQT, including the following:

- natural gas price volatility or a sustained period of lower commodity prices may have an adverse effect on EQT's drilling operations, revenue, profitability, future rate of growth and liquidity;
- a reduction in or slowing of EQT’s anticipated drilling and production schedule, which would directly and adversely impact demand for our services;
- infrastructure capacity constraints and interruptions;
- risks associated with the operation of EQT's wells, pipelines and facilities, including potential environmental liabilities;
- the availability of capital on a satisfactory economic basis to fund EQT's operations;
- EQT's ability to identify exploration, development and production opportunities based on market conditions;
- uncertainties inherent in projecting future rates of production;
- EQT's ability to develop additional reserves that are economically recoverable, to optimize existing well production and to sustain production;
- adverse effects of governmental and environmental regulation, changes in tax laws and negative public perception regarding EQT's operations;
- the loss of key personnel; and
- risk associated with cyber security threats.

Further, we are subject to the risk of non-payment or non-performance by EQT, including with respect to our gathering and compression agreements and water services agreements. We cannot predict the extent to which EQT’s business would be impacted if conditions in the energy industry were to deteriorate, nor can we estimate the impact such conditions would have on EQT’s ability to execute its drilling and development program or perform under our gas gathering and compression agreements or our water services agreements with EQT. Any material non-payment or non-performance by EQT could reduce our ability to make distributions to our unitholders.

Also, due to our relationship with EQT, our ability to access the capital markets, or the pricing or other terms of any capital markets transactions, may be adversely affected by any impairment to EQT’s financial condition or adverse changes in its credit ratings. Any material limitation on our ability to access capital as a result of such adverse changes at EQT could limit our ability to obtain future financing under favorable terms, or at all, or could result in increased financing costs in the future. Similarly, material adverse changes at EQT could negatively impact our unit price, limiting our ability to raise capital through equity issuances or debt financing, or could negatively affect our ability to engage in, expand or pursue our business activities, and could also prevent us from engaging in certain transactions that might otherwise be considered beneficial to us.

Unless we are successful in attracting significant unaffiliated third-party customers, our ability to maintain or increase the capacity subscribed and the volumes gathered on our gathering system will be dependent on receiving consistent or

increasing commitments from EQT. While EQT has dedicated acreage to us, and entered into long-term contracts for the services of our systems, it may determine in the future that drilling in areas outside of our dedicated acreage is strategically more attractive and it is under no contractual obligation to maintain its production dedicated to us. A reduction in the volumes gathered on our systems by EQT could have a material adverse effect on our business, financial condition, results of operations, liquidity or ability to make distributions to our unitholders. In addition, EQT has announced that its board of directors has formed a committee to evaluate options to address EQT's sum-of-the-parts discount, with the results of such review to be announced by the end of March 2018. There can be no assurance regarding the outcome of this review or how such outcome may involve or affect us.

Please see “Item 1A. Risk Factors” in EQT’s Annual Report on Form 10-K for the year ended December 31, 2017 (which is not, and shall not be deemed to be, incorporated by reference herein) for a full discussion of the risks associated with EQT’s business.

We may not generate sufficient cash from operations following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements to our general partner, to enable us to pay the minimum quarterly distribution to our unitholders.

We may not generate sufficient cash flow each quarter to support the payment of the minimum quarterly distribution or to increase our quarterly distributions in the future. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the volume of natural gas we gather and compress;
- the volume of fresh water we distribute and produced water we handle;
- the rates we charge for our gathering services and water services;
- the market price of natural gas and its effect on EQT’s and third parties’ drilling schedules as well as produced volumes;
- EQT’s and our third-party customers’ ability to fund their drilling programs;
- adverse weather conditions;
- the level of our operating, maintenance and general and administrative costs;
- regulatory action affecting the supply of, or demand for, natural gas, the rates we can charge for our services, how we contract for services, our existing contracts, our operating costs or our operating flexibility; and
- prevailing economic conditions.

In addition, the actual amount of cash we will have available for distribution will depend on other factors, including:

- the level, timing and amounts of capital expenditures we make, which amounts could be impacted by costs of labor and materials;
- our debt service requirements and other liabilities;
- our ability to make borrowings under our revolving credit facility to pay distributions;
- fluctuations in our working capital needs;
- restrictions on distributions contained in any of our debt agreements;
- the cost of acquisitions, if any;
- fees and expenses of our general partner and its affiliates (including EQT) we are required to reimburse;
- the amount of cash reserves established by our general partner; and
- other business risks affecting our cash levels.

Because of the natural decline in production from existing wells, our success depends, in part, on EQT’s ability to replace declining production and our ability to secure new sources of production from EQT or third parties. Additionally, our water services are directly associated with EQT's well completion activities and water needs, which are partially driven by horizontal lateral lengths and the number of completion stages per well. Any decrease in EQT's production or completion activity could adversely affect our business and operating results.

The natural gas volumes that support our gathering business depend on the level of production from natural gas wells connected to our systems, which may be less than expected and will naturally decline over time. If and to the extent EQT is able to execute its drilling program and achieve its anticipated production targets, the volumes of natural gas we gather should increase. To the extent EQT reduces its activity or otherwise ceases to drill and complete wells, revenues for our gathering and water services will be directly and adversely affected. Our ability to maintain water services revenues is substantially dependent on continued completion activity by EQT and third parties over time, including the volume of fresh water we distribute and produced water we handle for our customers. In addition, natural gas volumes from completed wells will naturally decline over time, and our cash flows associated with these wells will correspondingly decline. In order to maintain or increase throughput levels on our gathering systems, we must obtain new sources of natural gas from EQT or third parties. The primary factors affecting our ability to obtain additional sources of natural gas include (i) decisions by EQT and other producers regarding whether we, EQM or a third party gathers EQT's or such other producer's production in acreage that is not dedicated to us, (ii) the success of EQT's drilling activity or that by other producers in our areas of operation, (iii) EQT's acquisition of additional acreage that may be dedicated to us, which dedication generally will not be applicable to such additional acquired acreage unless it is in our dedicated areas and acquired by certain subsidiaries of EQT, and (iv) our ability to obtain acreage dedications from third parties. Our fresh water distribution services, which make up a substantial portion of our water services revenues, will be in greatest demand in connection with completion activities. To the extent that EQT or other fresh water distribution customers complete wells with shorter lateral lengths, the demand for our fresh water distribution services would be reduced from that needed for longer lateral lengths.

We have no control over EQT's or other producers' level of development and completion activity in our areas of operation, the amount of reserves associated with wells connected to our systems or the rate at which production from a well declines. In addition, our fresh water distribution business is dependent upon active development in our areas of operation. In order to maintain or increase throughput levels on our fresh water distribution systems, we must service new wells. We have no control over EQT or other producers or their development plan decisions, which are affected by, among other things:

- the availability and cost of capital;
- prevailing and projected natural gas, NGL and oil prices;
- the proximity, capacity, cost and availability of gathering and transportation facilities, and other factors that result in differentials to benchmark prices;
- demand for natural gas, NGLs and oil;
- levels of reserves;
- geologic considerations;
- environmental or other governmental regulations, including the availability of drilling permits, the regulation of hydraulic fracturing, the potential removal of certain federal income tax deductions with respect to natural gas and oil exploration and development or additional state taxes on natural gas extraction; and
- the costs of producing the natural gas and the availability and costs of drilling rigs and crews and other equipment.

EQT could elect to reduce its drilling activity if commodity prices decrease. Fluctuations in energy prices can also greatly affect the development of reserves. In general terms, the prices of natural gas, oil and other hydrocarbon products fluctuate in response to changes in supply and demand, market uncertainty and a variety of additional factors that are beyond our control. These factors include worldwide economic conditions, weather conditions and seasonal trends, the levels of domestic production and consumer demand, the levels of imported and exported natural gas, oil and liquefied natural gas, or LNG, the availability of transportation systems with adequate capacity, the volatility and uncertainty of regional pricing differentials, the price and availability of alternative fuels, the effect of energy conservation measures, the nature and extent of governmental regulation and taxation, and the anticipated future prices of natural gas, oil, LNG and other commodities. Declines in commodity prices could have a negative impact on EQT's development and production activity, and if sustained, could lead to a material decrease in such activity. Sustained reductions in development or production activity in our areas of operation could lead to reduced utilization

of our services.
In addition, substantially all of EQT’s natural gas production is sold to purchasers under contracts with market-based prices. The actual prices realized from the sale of natural gas differ from the quoted NYMEX Henry Hub price as a result of

location differentials. Location differentials in commodity prices, also known as basis differentials, result from differences between the price used to set the futures price for a commodity and the corresponding sales price at various regional sales points. The differential commonly is related to factors such as product quality, location, transportation capacity availability and contract pricing. Furthermore, the costs associated with securing long-term firm transportation capacity has risen significantly on newer projects. There can be no assurance that the net impact of entering into such arrangements, after giving effect to their costs, will result in more favorable sales prices for EQT's production in the future than local pricing alternatives.

Due to these and other factors, even if reserves are known to exist in areas serviced by our assets, producers have chosen, and may choose in the future, not to develop those reserves. If reductions in development activity result in our inability to maintain the current levels of throughput on our gathering systems or our water services, or if reductions in lateral lengths result in a decrease in demand for our water services on a per well basis, those reductions could reduce our revenue and cash flow and adversely affect our ability to make cash distributions to our unitholders.

Our assets are concentrated in three counties within the Appalachian Basin, making us vulnerable to risks associated with operating in one major geographic area.

We rely on revenues generated from our gathering systems, which are located in Washington and Greene Counties, Pennsylvania, and our water services assets, which are located in Washington and Greene Counties, Pennsylvania and Belmont County, Ohio. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, trucking shortages, availability of produced water disposal sites, market limitations, governmental regulations impacting the use of water in well completion activities, cold weather conditions or interruption of the processing or transportation of natural gas and NGLs.

Insufficient takeaway capacity in the Appalachian Basin could cause decreased producer activity in our dedicated areas. The Appalachian Basin has recently experienced periods in which natural gas production has surpassed local takeaway capacity, resulting in substantial discounts in the price received by producers selling into the Appalachia markets. Although additional Appalachian Basin takeaway capacity has been added in recent years and additional capacity is being constructed, the existing and expected capacity may not be sufficient to keep pace with the increased production caused by drilling in the area. If our customers are unable to secure long-term firm takeaway capacity on major pipelines that connect to our gathering systems to accommodate their growing production and to manage their basis differentials, it could impact their development plans and cause a decrease in throughput on our gathering systems. Any of the aforementioned throughput decreases could have a material adverse effect on our business, financial condition, results of operations, liquidity or ability to make distributions to our unitholders.

Further, a number of areas within the Marcellus Shale have historically been subject to longwall coal mining operations. For example, third parties may conduct longwall coal mining operations near or under EQT's, our other customers' or our properties, which could cause subsidence or other damage to EQT's, our other customers' or our properties, adversely impact our customers' drilling or adversely impact our gathering activities. In such event, our or our customers' operations may be impaired or interrupted, which could have a material adverse effect on our business, financial condition, results of operations, liquidity or ability to make distributions to our unitholders.

Finally, gathering and water services require special equipment and laborers skilled in multiple disciplines, such as equipment operators, mechanics and engineers, among others. The increased levels of production in the Appalachian Basin may result in a shortage of equipment and skilled labor. If we experience such shortages, our labor and equipment costs and overall productivity could be materially and adversely affected. If our equipment or labor prices increase, our results of operations could be materially and adversely affected.

We may not be able to attract additional third-party gathering and compression volumes or opportunities to provide water services, which could limit our ability to grow and increase our dependence on EQT.

Part of our long-term growth strategy includes identifying additional opportunities to offer services to third parties. For the year ended December 31, 2017, EQT (including Rice Energy with respect to the period prior to the Mergers) accounted for substantially all of our gas gathering and compression revenues and 96% of our water services revenues. Our ability to increase throughput on our gathering and water services systems and any related revenue from third parties is subject to numerous factors beyond our control, including competition from third parties and the extent to which we have available capacity when requested by third parties. To the extent that we lack available capacity on our systems for third-party volumes, we may not be able to compete effectively with third-party systems for additional volumes in our dedicated areas. In addition, some of our competitors for third-party volumes have greater financial resources and access to larger supplies of natural gas than those available to us, which could allow those competitors to price their services more aggressively than we do.

Our efforts to attract new unaffiliated customers may be adversely affected by (i) our relationship with EQT and the fact that a substantial portion of the capacity of our gathering and water services systems will be necessary to service EQT's production and development and completion schedule, (ii) our desire to provide services pursuant to fee-based contracts and (iii) the existence of current and future dedications to other gatherers by potential third-party customers. As a result, we may not have the capacity to provide services to third parties and/or potential third-party customers may prefer to obtain services pursuant to other forms of contractual arrangements under which we would be required to assume direct commodity exposure.

Increased competition from other companies that provide gathering services, or from alternative fuel sources, could have a negative impact on the demand for our services, which could adversely affect our financial results.

Our ability to renew or replace existing contracts at rates sufficient to maintain current revenues and cash flows could be adversely affected by the activities of our competitors. Our systems compete primarily with other natural gas gathering systems. Some of our competitors have greater financial resources and may now, or in the future, have access to greater supplies of natural gas than we do. Some of these competitors may expand or construct gathering systems that would create additional competition for the services we provide to our customers. In addition, our customers may develop their own gathering systems instead of using ours. Moreover, EQT and its affiliates, including EQM, are not limited in their ability to compete with us outside of our dedicated areas.

Further, natural gas as a fuel competes with other forms of energy available to end-users, including coal, liquid fuels and renewable and alternative energy. Increased demand for such forms of energy at the expense of natural gas could lead to a reduction in demand for natural gas gathering services.

All of these competitive pressures could make it more difficult for us to retain our existing customers and/or attract new customers as we seek to expand our business, which could have a material adverse effect on our business, financial condition, results of operations, liquidity or ability to make distributions to our unitholders. In addition, competition could intensify the negative impact of factors that decrease demand for natural gas in the markets served by our systems, such as adverse economic conditions, weather, higher fuel costs and taxes or other governmental or regulatory actions that directly or indirectly increase the cost or limit the use of natural gas.

We will be required to make capital expenditures to increase our asset base. If we are unable to obtain needed capital or financing on satisfactory terms, our ability to make cash distributions to our unitholders may be diminished or our financial leverage could increase.

In order to increase our asset base, we will need to make expansion capital expenditures. If we do not make sufficient or effective expansion capital expenditures, we will be unable to expand our business operations and, as a result, we will be unable to raise the level of our future cash distributions. To fund our capital expenditures, we will be required to use cash from our operations and/or incur borrowings. Such uses of cash from our operations will reduce cash available for distribution to our unitholders. Alternatively, we may sell additional common units or other securities to fund our capital expenditures. Our ability to obtain bank financing or our ability to access the capital markets for future equity or debt offerings may be limited by our or EQT's financial condition at the time of any such financing or offering and the covenants in our existing debt agreements, as well as by general economic conditions, contingencies and uncertainties that are beyond our control. Even if we are successful in obtaining the necessary funds, the terms of such financings could limit our ability to pay distributions to our unitholders. In addition, incurring additional debt may significantly increase our interest expense and financial leverage, and issuing additional limited partner interests may result in significant unitholder dilution and would increase the aggregate amount of cash required to maintain the then-current distribution rate, which could materially decrease our ability to pay distributions at the prevailing distribution rate. None of our general partner, EQT or any of their respective affiliates is committed to providing any direct or indirect support to fund our growth.

The amount of cash we have available for distribution to our unitholders depends primarily on our cash flow and not solely on profitability, which may prevent us from making distributions, even during periods in which we record net income.

The amount of cash we have available for distribution depends primarily upon our cash flow and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record a net loss for financial accounting purposes, and conversely, we might fail to make cash distributions during periods when we record net income for financial accounting purposes.

An impairment of goodwill could result in a negative impact on our financial condition and results of operations.
At December 31, 2017, goodwill was approximately $1.3 billion, or 47% of our total assets. Goodwill results from acquisitions, and represents the excess of the acquisition consideration over fair value of the net tangible and other identifiable

intangible assets we recorded as a result of the acquisition. Accounting principles generally accepted in the United States (GAAP) requires us to periodically test goodwill for impairment. If we were to determine that our goodwill were impaired, we would be required to take an immediate charge to earnings with a corresponding reduction of partners' equity. Such charges could be material to our results of operations and could adversely impact our financial condition and results of operations.

Our construction or purchase of new gathering, water, or other assets may not result in revenue increases and may be subject to regulatory, environmental, political, legal and economic risks, which could adversely affect our business, financial condition, results of operations, liquidity or ability to make distributions to our unitholders.

The construction of additions or modifications to our existing systems and the construction or purchase of new assets involve numerous regulatory, environmental, political and legal uncertainties beyond our control and may require the expenditure of significant amounts of capital. Financing may not be available on economically acceptable terms or at all. If we undertake these projects, we may not be able to complete them on schedule, at the budgeted cost or at all. Moreover, our revenues may not increase immediately upon the expenditure of funds on a particular project. We may construct facilities to capture anticipated future production growth in an area in which such growth does not materialize. As a result, new gathering, water, or other assets may not be able to attract enough throughput to achieve our expected investment return, which could adversely affect our business, financial condition, results of operations, liquidity or ability to make distributions to our unitholders. In addition, the construction of additions to our existing assets may require us to obtain new rights-of-way prior to constructing new pipelines or facilities. We may be unable to timely obtain such rights-of-way to connect new natural gas or water supplies to our existing gathering and water systems or capitalize on other attractive expansion opportunities. Further, we do not own all of the land on which our pipelines and facilities are or may be constructed, and we are, therefore, subject to the possibility of more onerous terms or increased costs to retain necessary land use if we do not have valid rights-of-way or if such rights-of-way lapse or terminate. Additionally, it may become more expensive for us to obtain new rights-of-way or to expand or renew existing rights-of-way. If the cost of renewing or obtaining new rights-of-way increases, our cash flows could be adversely affected.

Our exposure to commodity price risk may change over time.

We currently generate all of our gathering and compression revenues pursuant to fee-based contracts under which we are paid based on the volumes that we gather and compress, rather than the underlying value of the commodity. Consequently, our existing operations and cash flows have no direct exposure to commodity price risk. Although we intend to enter into similar fee-based contracts with new customers in the future, our efforts to negotiate such contractual terms may not be successful. In addition, we may acquire or develop additional midstream assets in a manner that increases our exposure to commodity price risk. Future exposure to the volatility of natural gas, NGL and oil prices could have a material adverse effect on our business, financial condition, results of operations, liquidity or ability to make distributions to our unitholders. However, we have some indirect exposure to commodity prices and basis differentials in that persistently low realized sales prices by our customers may cause them to delay drilling or shut in production, which would reduce the volumes of natural gas available for gathering and compression on our systems. Please read "Item 7A. Quantitative and Qualitative Disclosures about Market Risk."

Restrictions in our revolving credit facility could adversely affect our business, financial condition, results of operations, liquidity or ability to make distributions to our unitholders.

Our revolving credit facility contains various covenants and restrictive provisions that limit our ability to, among other things:

- incur or guarantee additional debt;
- redeem or repurchase units or make distributions under certain circumstances;
- make certain investments and acquisitions;
- incur certain liens or permit them to exist;
- enter into certain types of transactions with affiliates;
- merge or consolidate with another company; and
- transfer, sell or otherwise dispose of assets.

Our revolving credit facility also contains covenants requiring us to maintain certain financial ratios. Our ability to meet those financial ratios and tests can be affected by events beyond our control, and there is no assurance that that we will meet any such ratios and tests.

The provisions of our revolving credit facility may affect our ability to obtain future financing and pursue attractive business opportunities and our flexibility in planning for, and reacting to, changes in business conditions. In addition, a failure to comply with the provisions of our revolving credit facility could result in a default or an event of default that could enable our lenders to declare the outstanding principal of that debt, together with accrued and unpaid interest, to be immediately due and payable. If the payment of our debt is accelerated, our assets may be insufficient to repay such debt in full, and our unitholders could experience a partial or total loss of their investment. Please read "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Capital Resources and Liquidity."

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

Our future level of debt could have important consequences to us, including the following:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures (including required well pad connections and well connections pursuant to our gas gathering and compression agreements as well as acquisitions) or other purposes may be impaired or such financing may not be available on favorable terms;
- our funds available for operations, future business opportunities and distributions to unitholders will be reduced by that portion of our cash flow required to make interest payments on our debt;
- we may be more vulnerable to competitive pressures or a downturn in our business or the economy generally; and
- our flexibility in responding to changing business and economic conditions may be limited.

Our ability to service our debt will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control. If our operating results are not sufficient to service any future indebtedness, we will be forced to take actions such as reducing distributions to our unitholders, reducing or delaying our business activities, investments or capital expenditures, selling assets or issuing equity. We may not be able to effect any of these actions on satisfactory terms or at all.

Increases in interest rates could adversely affect our business, our unit price and our ability to issue additional equity, to incur debt to capture growth opportunities or for other purposes, or to make cash distributions to our unitholders at our intended levels.

If interest rates rise, the interest rates on our revolving credit facility, future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly. As with other yield-oriented securities, our unit price is impacted by the level of our cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank related yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our units, and a rising interest rate environment could have an adverse impact on our unit price and our ability to issue additional equity, to incur debt to expand or for other purposes, or to make cash distributions at our intended levels.

The credit and risk profile of EQT could adversely affect our credit ratings and risk profile, which could increase our borrowing costs or hinder our ability to raise capital.

The credit and business risk profiles of EQT may be a factor considered in credit evaluations of us. This is because EQT controls our business activities, including our cash distribution policy and growth strategy. Any adverse change in the financial condition of EQT, including the degree of its financial leverage and its dependence on cash flow from us to service its indebtedness, or a downgrade of EQT's credit rating, may adversely affect our credit ratings and risk profile.

If we were to seek a credit rating in the future, our credit rating may be adversely affected by the leverage of EQT, as credit rating agencies such as Standard & Poor's Ratings Services and Moody's Investors Service may consider the leverage and credit profile of EQT and its affiliates because of their ownership interest in and control of us. Any adverse effect on our credit rating would increase our cost of borrowing or hinder our ability to raise financing in the capital markets, which would impair our ability to grow our business and make distributions to our unitholders.

If we are unable to make acquisitions on economically acceptable terms from third parties, our future growth will be limited, and the acquisitions we do make may reduce, rather than increase, our cash available for distribution on a per unit basis.

Our ability to grow depends, in part, on our ability to make acquisitions that increase our cash generated from operations on a per unit basis. The acquisition component of our strategy is based, in large part, on our ability to acquire midstream energy assets from industry participants. In that regard, EQT has publicly announced its intention to sell Rice Energy's retained midstream assets acquired by EQT in connection with the Mergers to EQM. Furthermore, many other factors could impair our access to future midstream assets and the willingness of EQT to offer us acquisition opportunities, including EQT's relationship with EQM and EQGP, a change in control of EQT or a transfer of the incentive distribution rights held by EQT. Any material reduction in opportunities offered to us to acquire midstream assets would limit our future growth and our ability to increase distributions.

If we are unable to make accretive acquisitions, whether because, among other reasons, (i) EQT elects not to sell or contribute additional assets to us, (ii) we are unable to identify attractive third-party acquisition opportunities, (iii) we are unable to negotiate acceptable purchase contracts with EQT or third parties, (iv) we are unable to obtain financing for these acquisitions on economically acceptable terms, (v) we are outbid by competitors or (vi) we are unable to obtain necessary governmental or third-party consents, then our future growth and ability to increase distributions will be limited. Furthermore, even if we do make acquisitions that we believe will be accretive, these acquisitions may nevertheless result in a decrease in the cash available for distribution on a per unit basis.

Any acquisition involves potential risk. The risks include, 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;
- an inability to integrate successfully the assets or businesses we acquire;
- the assumption of unknown liabilities for which we are not indemnified or for which our indemnity is inadequate;
- limitations on rights to indemnity from the seller;
- mistaken assumptions about the overall costs of equity or debt;
- the diversion of management's and employees' attention from other business concerns; and
- unforeseen difficulties operating in new geographic areas or business lines.

If any acquisition eventually proves not to be accretive to our cash available for distribution per unit, it could have a material adverse effect on our business, financial condition, results of operations, liquidity or ability to make distributions to our unitholders.

The demand for the services provided by our water distribution business could decline as a result of several factors.

Our water services business includes fresh water distribution for use in our customers' natural gas, NGL and oil exploration and production activities. Water is an essential component of natural gas, NGL and oil production during the drilling, and in particular, the hydraulic fracturing process. As a result, the demand for our fresh water distribution and produced water handling services is tied to the level of drilling and completion activity of our customers, including EQT, which is currently and will continue to be our primary customer for such services. More specifically, the demand for our water distribution and produced water handling services could be adversely affected by any reduction in or slowing of EQT's or other customers' well completions, any reduction in produced water attributable to completion activity, or to the extent that EQT or other customers complete wells with shorter lateral lengths, which would lessen the volume of fresh water required for completion activity.

Additionally, we depend on EQT to source a portion of the fresh water we distribute. The availability of our and EQT's water supply may be limited due to reasons including, but not limited to, prolonged drought. Restrictions on the ability to obtain water or changes in wastewater disposal requirements may incentivize water recycling efforts by oil and natural gas producers, which could decrease the demand for our fresh water distribution services.

A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of such assets, which may cause our revenues to decline and our operating expenses to increase.

Our natural gas gathering operations are exempt from regulation by the FERC, under the NGA. Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by the FERC as a natural gas company under the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional tests the FERC has used to determine whether a pipeline is a gathering pipeline not subject to FERC jurisdiction. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is often the subject of litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by the FERC, the courts, or Congress. If the FERC

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were to determine that all or some of our gathering facilities and/or services provided by us are not exempt from FERC regulation, the rates for, and terms and conditions of, services provided by such facility would be subject to regulation by the FERC, which could in turn decrease revenue, increase operating costs, and, depending upon the facility in question, adversely affect our results of operations and cash flows.

Other FERC regulations may indirectly impact our businesses and the markets for products derived from these businesses. FERC's policies and practices across the range of its natural gas regulatory activities, including, for example, its policies on open access transportation, ratemaking, gas quality, capacity release and market center promotion, may indirectly affect the intrastate natural gas market. Should we fail to comply with any applicable FERC administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines, which could have a material adverse effect on our business, financial condition, results of operations, liquidity or ability to make distributions to our unitholders. FERC is authorized to impose civil penalties of up to approximately $1.2 million per violation, per day for violations of the NGA, the NGPA or the rules, regulations, restrictions, conditions and orders promulgated under those statutes. This maximum penalty authority established by statute will continue to be adjusted periodically for inflation.

State regulation of natural gas gathering facilities and intrastate transportation pipelines generally includes various safety, environmental and, in some circumstances, nondiscriminatory take and common purchaser requirements, as well as complaint-based rate regulation. While we have not obtained a specific determination from the applicable state regulators, we believe our natural gas gathering facilities are not subject to rate regulation or open access requirements by state regulators. However, state regulators, such as the Pennsylvania Public Utilities Commission may require us to register as pipeline operators, pay assessment and registration fees, undergo inspections and report annually on the miles of pipeline we operate. Other state regulations may not directly apply to our business, but may nonetheless affect the availability of natural gas for purchase, compression and sale.

Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels. Our gathering operations could be adversely affected in the future should we become subject to the application of state or federal regulation of rates and services. These operations may also be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of such facilities. We cannot predict what effect, if any, such changes might have on our operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes. For more information regarding federal and state regulation of our operations, please read "Item 1. Business-Regulation of Operations."

Increased regulation of hydraulic fracturing could result in reductions or delays in natural gas, NGL and oil production by our customers, which could reduce the throughput on our gathering systems, the number of wells for which we provide water services, which could and adversely impact our revenues.

All of EQT's natural gas production gathered by us is being developed from shale formations. These reservoirs require hydraulic fracturing completion processes to release the liquids and natural gas from the rock so it can flow through casing to the surface.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. Hydraulic fracturing involves the injection of water, sand or alternative proppant and chemicals under pressure into target geological formations to fracture the surrounding rock and stimulate production. Our anchor customer, EQT, regularly uses hydraulic fracturing as part of its operations. Hydraulic fracturing is typically regulated by state oil and natural gas commissions and similar agencies, but, in response to increased public concern regarding the alleged potential impacts of hydraulic fracturing, the EPA has asserted federal regulatory authority pursuant to SDWA over certain hydraulic fracturing activities involving the use of diesel fuels and published permitting guidance in February 2014 addressing the performance of such activities using diesel fuels. The EPA has also issued final regulations under the CAA establishing performance standards, including standards for the capture of air emissions released during hydraulic fracturing, published a notice of proposed rulemaking under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing, and finalized rules in June 2016 that prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. The EPA announced its intention to reconsider the CAA performance standards rule in April 2017 and has sought to stay its requirements. However, the rule remains in effect.

These rules, if not changed or withdrawn, will continue to require changes to our operations, including the installation of new equipment to control emissions. In addition, the BLM finalized rules in March 2015 that imposed new or more stringent standards for performing hydraulic fracturing on federal and American Indian lands. The BLM rule was struck down by a federal court in Wyoming in June 2016, but reinstated on appeal by the Tenth Circuit in September 2017. While this appeal was pending, the BLM proposed a rulemaking in July 2017 to rescind these rules in their entirety. Although the BLM published a final rule rescinding the 2015 rules in December 2017, other federal or state agencies may look to the BLM rule in developing new regulations that could apply to our operations.

Various state and federal agencies are studying the potential environmental impacts of hydraulic fracturing. In December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report, contrary to several previously published draft reports issued by the EPA, found instances in which impacts to drinking water may occur. However, the report also noted significant data gaps that prevented the EPA from determining the extent or severity of these impacts. The results of such reviews or studies could spur initiatives to further regulate hydraulic fracturing.

Along with several other states, Pennsylvania (where we currently operate) has adopted laws and regulations that impose more stringent disclosure and well construction requirements on hydraulic fracturing operations, and local governments may also adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular, or prohibiting such activities. In addition, various studies are underway by the EPA and other federal agencies concerning the potential environmental impacts of hydraulic fracturing activities. At the same time, certain environmental groups have advocated for additional laws to more closely and uniformly regulate the hydraulic fracturing process, and legislation has been proposed by members of Congress from time to time to provide for such regulation. We cannot predict whether any such legislation will be enacted and if so, what its provisions would require. Additional levels of regulation and permits potentially required by new laws and regulations at the federal, state or local level could lead to delays, increased operating costs and process prohibitions for EQT or other potential customers that could reduce the volumes of natural gas that move through our gathering systems or reduce the number of wells drilled and completed that require fresh water for hydraulic fracturing systems, which in turn could materially adversely affect our revenues and results of operations.

Our operations, as well as our customers' operations, are subject to significant liability under, or costs and expenditures to comply with, environmental and worker health and safety regulations, which are complex and subject to frequent change.

As an owner, lessee or operator of gathering pipelines and compressor stations, we are subject to various stringent federal, state, and local laws and regulations relating to the discharge of materials into, and protection of, the environment. Numerous governmental authorities, such as the EPA and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly response actions. These laws and regulations may impose numerous obligations that are applicable to our and our customers' operations, including the acquisition of permits to conduct regulated activities, the incurrence of capital or operating expenditures to limit or prevent releases of materials from our or our customers' operations, the imposition of specific standards addressing worker protection, and the imposition of substantial liabilities and remedial obligations for pollution or contamination resulting from our and our customers' operations. Failure to comply with these laws, regulations and permits may result in joint and several, strict liability for administrative, civil and/or criminal penalties, the imposition of remedial obligations, and the issuance of injunctions limiting or preventing some or all of our operations. Private parties, including the owners of the properties through which our gathering systems pass and facilities where wastes resulting from our operations are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance, as well as to seek damages for non-compliance, with environmental laws, regulations and permits or for personal injury or property damage. We may not be able to recover all or any of these costs from insurance. We may also experience a delay in obtaining or be unable to obtain required permits, which may cause us to lose potential and current customers, interrupt our operations and limit our growth and revenues, which in turn could affect our profitability. In addition, our customers' liability under, or costs and expenditures to comply with, environmental and worker health and safety regulations could lead to delays and increased operating costs, which could reduce the volumes of natural gas that move through our gathering systems. There is no assurance that changes in or additions to public policy regarding the protection of the environment will not have a significant impact on our operations and profitability.

Our operations also pose risks of environmental liability due to leakage, migration, releases or spills from our operations to surface or subsurface soils, surface water or groundwater. Certain environmental laws impose strict as well as joint and several liability for costs required to remediate and restore sites where hazardous substances, hydrocarbons, or solid wastes have been stored or released. We may be required to remediate contaminated properties currently or formerly operated by us or facilities of third parties that received waste generated by our operations regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations. Moreover, public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stringent environmental legislation and regulations applied to the crude oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. Please read “Item 1. Business—Regulation of Environmental and Occupational Safety and Health Matters” for more information.

Climate change laws and regulations restricting emissions of GHGs could result in increased operating costs and reduced demand for the natural gas that we gather, while potential physical effects of climate change could disrupt our operations and cause us to incur significant costs in preparing for or responding to those effects.

In December 2009, the EPA determined that emissions of GHGs present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA adopted regulations under existing provisions of the CAA that establish pre-construction and operating permit requirements for GHG emissions from certain large stationary sources. Under these regulations, for example, facilities required to obtain PSD permits because they are potential major sources of criteria pollutants must comply with BACT-driven GHG permit limits established by the states or, in some cases, by the EPA, on a case-by-case basis. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States, including, among others, certain onshore oil and natural gas processing and fractionating facilities as well as gathering and boosting facilities. We are monitoring GHG emissions from our operations in accordance with the GHG emissions reporting rule. Also, in May 2016, the EPA finalized rules that impose volatile organic compound emissions limits (and collaterally reduce methane emissions) on certain types of compressors and pneumatic pumps, as well as requiring the development and implementation of leak monitoring plans for compressor stations. The EPA announced its intention to reconsider certain of the rules in April 2017 and has sought to stay their requirements. However, the rules remain in effect. These regulations, if not changed or withdrawn, will continue to require changes to our operations, including the installation of new equipment to control emissions. Several states are also pursuing similar measures to regulate emissions of GHGs from new and existing sources. If enacted or promulgated, additional GHG regulations could impose new compliance costs and permitting burdens on our operations.

Also, in November 2016, the BLM finalized, and in December 2016 the PADEP announced that it intends to propose, rules related to the control of methane emissions. Certain provisions of the BLM rule went into effect in January 2017, while others were scheduled to go into effect in January 2018. In December 2017, the BLM published a final rule delaying the 2018 provisions until 2019. The final draft of the PADEP rule was released in November 2017, and the PADEP hopes to finalize the regulations in early 2018. Compliance with rules to control methane emissions will likely require enhanced record-keeping practices, the purchase of new equipment such as optical gas imaging instruments to detect leaks, and the increased frequency of maintenance and repair activities to address emissions leakage. The rules will also likely require hiring additional personnel to support these activities or the engagement of third party contractors to assist with and verify compliance. These new rules could result in increased compliance costs on our operations. The PADEP also recently announced an initiative to restrict methane emissions from natural gas development activities. Under the proposed changes, operators in Pennsylvania would need to (i) obtain an air quality general permit in advance of operations, (ii) control releases, and (iii) report emissions.

Additionally, while Congress has from time to time considered legislation to reduce emissions of GHGs, the prospect for adoption of significant legislation at the federal level to reduce GHG emissions is perceived to be low at this time. However, many states have adopted cap and trade programs or renewable energy portfolio standards in an effort to reduce GHG emissions, and these efforts are likely to continue absent additional federal action. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations that limit emissions of GHGs could adversely affect demand for the oil and natural gas that exploration and production operators produce, some of whom are our customers, which could thereby reduce demand for our midstream services. Finally, it should be noted that scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events; if any such effects were to occur, it is uncertain if they would have an adverse effect on our business, financial condition, results of operations, liquidity or ability to make distributions to our unitholders.

Negative public perception regarding us and/or the midstream industry could have an adverse effect on our business, financial condition, results of operations, liquidity or ability to make distributions to our unitholders.

Negative public perception regarding us and/or the midstream industry resulting from, among other things, oil spills, the explosion of natural gas transmission and gathering lines and concerns raised by advocacy groups about hydraulic fracturing and pipeline projects, may lead to increased regulatory scrutiny which may, in turn, lead to new local, state and federal safety and environmental laws, regulations, guidelines and enforcement interpretations. These actions may cause operational delays or restrictions, increased operating costs, additional regulatory burdens and increased risk of litigation. Moreover, governmental authorities exercise considerable discretion in the timing and scope of permit issuance and the public may engage in the permitting process, including through intervention in the courts. Negative public perception could cause the permits we need to conduct our operations to be withheld, delayed or burdened by requirements that restrict our ability to profitably conduct business.

We may incur significant costs and liabilities as a result of pipeline integrity management program testing and any related pipeline repair or preventative or remedial measures.

The DOT has adopted regulations requiring pipeline operators to develop integrity management programs for transportation pipelines located where a leak or rupture could do the most harm in HCAs. The regulations require operators to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact an HCA;
- improve data collection, integration and analysis;
- repair and remediate the pipeline as necessary; and
- implement preventive and mitigating actions.

The 2011 Pipeline Safety Act, among other things, increases the maximum civil penalty for pipeline safety violations and directs the Secretary of Transportation to promulgate rules or standards relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation and testing to confirm the material strength of pipe operating above 30% of specified minimum yield strength in HCAs. PHMSA has the authority to impose civil penalties for pipeline safety violations up to a maximum of approximately $200,000 per day for each violation and approximately $2 million for a related series of violations. This maximum penalty authority established by statute will continue to be adjusted periodically to account for inflation. Should our operations fail to comply with PHMSA or comparable state regulations, we could be subject to substantial penalties and fines. States also are pursuing regulatory programs intended to ensure the safety of pipeline infrastructure and construction.

In January 2017, PHMSA announced a new final rule regarding hazardous liquid pipelines, which increases the quality and frequency of tests that assess the condition of pipelines, requires operators to annually evaluate the existing protective measures in place for pipeline segments in HCAs, extends certain leak detection requirements for hazardous liquid pipelines not located in HCAs, and expands the list of conditions that require immediate repair. However, it is unclear when or if this rule will go into effect because, on January 20, 2017, the Trump Administration requested that all regulations that had been sent to the Office of the Federal Register, but were not yet published, be immediately withdrawn for further review. Accordingly, this rule has not become effective through publication in the Federal Register. PHMSA also proposed rules in April 2016 that would, if adopted, impose more stringent requirements for certain gas lines. Among other things, the proposed rulemaking would extend certain of PHMSA's current regulatory safety programs for gas pipelines beyond HCAs to cover gas pipelines found in newly defined "moderate consequence areas" that contain as few as five dwellings within the potential impact area and would also require gas pipelines installed before 1970 that are currently exempted from certain pressure testing obligations to be tested to determine their MAOP. Other new requirements proposed by PHMSA under the rulemaking would require pipeline operators to: report to PHMSA in the event of certain MAOP exceedances; strengthen PHMSA integrity management requirements; consider seismicity in evaluating threats to a pipeline; conduct hydrostatic testing for all pipeline segments manufactured using longitudinal seam welds; and use more detailed guidance from PHMSA in the selection of assessment methods to inspect pipelines. The proposed rulemaking also seeks to impose a number of requirements on gathering lines. Moreover, in June 2016, President Obama signed the 2016 Pipeline Safety Act into law. The 2016 Pipeline Safety Act reauthorizes PHMSA through 2019, and facilitates greater pipeline safety by providing PHMSA with emergency order authority, including authority to issue prohibitions and safety measures on owners and operators of gas or hazardous liquid pipeline facilities to address imminent hazards, without prior notice or an opportunity for a hearing, as well as enhanced release reporting requirements, requiring a review of both natural gas and hazardous liquid integrity management programs, and mandating the creation of a working group to consider the development of an information-sharing system related to integrity risk analyses. Pursuant to those provisions of the 2016 Pipeline Safety Act, in October 2016 and December 2016, PHMSA issued two separate Interim Final Rules that expanded the agency's authority to impose emergency restrictions, prohibitions and safety measures and strengthened the rules related to underground natural gas storage facilities, including well integrity, wellbore tubing and casing integrity. The December 2016 Interim Final Rule, relating to underground gas storage facilities, went into effect in January 2017, with a compliance deadline in January 2018. PHMSA determined, however, that it will not issue enforcement citations to any operators for violations of provisions of the December 2016 Interim Final Rule that had previously been non-mandatory provisions of American Petroleum Institute Recommended Practices 1170 and 1171 until one year after PHMSA issues a final rule. In October 2017, PHMSA formally reopened the comment period on the December 2016 Interim Final Rule in response to a petition for reconsideration, with comments due in November 2017. This matter remains ongoing and subject to future PHMSA determinations. While we cannot predict the outcome of legislative or regulatory initiatives, such legislative and regulatory changes could have a material effect on our business, financial condition, results of operations, liquidity or ability to make distributions to our unitholders. We are monitoring and evaluating the effect of these and other emerging requirements on our operations. Please read "Item 1. Business-Regulation of Operations—Pipeline Safety Regulation" for more information.

Our business involves many hazards and operational risks, some of which may not be fully covered by insurance. The occurrence of a significant accident or other event that is not fully insured could curtail our operations and have a material adverse effect on our business, financial condition, results of operations, liquidity or ability to make distributions to our unitholders.

Our operations are subject to all of the hazards inherent in the gathering of natural gas, including:

- damage to pipelines, compressor stations, equipment and surrounding properties caused by hurricanes, earthquakes, tornadoes, floods, fires, landslides and other natural disasters and acts of sabotage and terrorism;
- damage from construction, farm and utility equipment, as well as other subsurface activity (for example, mine subsidence);
- leaks of natural gas or losses of natural gas as a result of the malfunction of equipment or facilities;
- ruptures and explosions;
- other hazards that could also result in personal injury and loss of life, pollution and suspension of operations; and
- hazards experienced by other operators that may affect our operations by instigating increased regulations and oversight.

Any of these risks could adversely affect our ability to conduct operations or result in substantial loss to us as a result of claims for:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

We may elect not to obtain insurance for any or all of these risks if we believe that the cost of available insurance is excessive relative to the risks presented. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition, results of operations, liquidity or ability to make distributions to our unitholders.

We do not have any officers or employees apart from those seconded to us and rely solely on officers of our general partner and employees of EQT.

We are managed and operated by the board of directors of our general partner. Affiliates of EQT conduct businesses and activities of their own in which we have no economic interest. As a result, there could be material competition for the time and effort of the officers and employees who provide services to our general partner, EQM, EQM's general partner, EQGP, EQGP's general partner and EQT. While we expect the officers and employees who provide services to our general partner to devote sufficient attention to the management and operation of our business, if they do not devote sufficient attention our financial results may suffer, and our ability to make distributions to our unitholders may be reduced.

Terrorist or cyber security attacks or threats thereof aimed at our facilities or surrounding areas could adversely affect our business.

Our business has become increasingly dependent upon digital technologies, including information systems, infrastructure and cloud applications, to operate our assets, and the maintenance of our financial and other records has long been dependent upon such technologies. The U.S. government has issued public warnings that indicate that energy assets might be specific targets of cyber security threats. Deliberate attacks on, or unintentional events affecting, our systems or infrastructure, the systems or infrastructure of third parties or the cloud could lead to corruption or loss of our proprietary data and potentially sensitive data, delays in delivery of natural gas and natural gas liquids, difficulty in completing and settling transactions, challenges in maintaining our books and records, environmental damage, communication interruptions, personal injury, property damage, other operational disruptions and third party liability. Further, as cyber incidents continue to evolve, we may be required to expend additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber incidents.

Risks Related to Our Partnership Structure

Our general partner and its affiliates, including EQT, which owns our general partner, may have conflicts of interest with us and limited duties to us and our unitholders, and they may favor their own interests to the detriment of us and our other common unitholders.

EQT indirectly owns and controls our general partner and appoints all of the officers and directors of our general partner. All of our officers and a majority of our directors are also officers and/or directors of EQT. Although our general partner has a duty to manage us in a manner that is beneficial to us and our unitholders, the directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner that is beneficial to EQT. Further, our directors and officers who are also directors and officers of EQT have a fiduciary duty to manage EQT in the best interests of the shareholders of EQT. Additionally, EQT also controls EQM's general partner and EQGP's general partner and has the power to appoint all of the officers and directors of EQM's general partner and EQGP's general partner. Conflicts of interest will arise between EQT and any of its affiliates, including EQM, EQGP, EQM's general partner, EQGP's general partner and our general partner, on the one hand, and us and our common unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of EQT, EQM and EQGP over our interests and the interests of our unitholders. These conflicts include the following situations, among others:

- neither our partnership agreement nor any other agreement requires EQT to pursue a business strategy that favors us, and the directors and officers of EQT have a fiduciary duty to make these decisions in the best interests of EQT, which may be contrary to our interests. EQT may choose to shift the focus of its investment and growth to areas not served by our assets;
- EQT, as our anchor customer, has an economic incentive to cause us not to seek higher gathering fees and water service fees, even if such higher fees would reflect fees that could be obtained in arm's-length, third-party transactions;
- EQT may choose to shift the focus of its investment and operations to areas not serviced by our assets, including areas serviced by EQM;
- EQT may choose to allocate capital and costs among EQGP, EQM and us in a manner that is not favorable to us;
- actions taken by our general partner may affect the amount of cash available to pay distributions to our unitholders;
- all of the officers and six of the directors of our general partner are also officers and/or directors of EQT and owe fiduciary duties to EQT; all of the officers and five of the directors of our general partner as also officers and/or directors of EQM's general partner and owe fiduciary duties to EQM; and three of the officers and four of the directors of our general partner are also officers and/or directors of EQGP's general partner and owe fiduciary duties to EQGP. The officers of our general partner also devote significant time to the business of EQT, EQM and EQGP and are compensated by EQT accordingly;
- our general partner is allowed to take into account the interests of parties other than us, such as EQT, in exercising certain rights under our partnership agreement, including with respect to conflicts of interest;
- except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval;
- our general partner may cause us to borrow funds in order to permit the payment of cash distributions;
- disputes may arise under our commercial agreements with EQT and its affiliates;
- our general partner determines the amount and timing of asset purchases and sales, borrowings, issuances of additional partnership securities and the level of reserves, each of which can affect the amount of cash that is distributed to our unitholders;

- our general partner determines the amount and timing of any capital expenditure and the amount of estimated maintenance capital expenditures, which reduces operating surplus. The determination of estimated maintenance capital expenditures can affect the amount of cash from operating surplus that is distributed to our unitholders;
- our partnership agreement limits the liability of, and replaces the duties owed by, our general partner and also restricts the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty;
- common unitholders have no right to enforce obligations of our general partner and its affiliates under agreements with us;
- contracts between us, on the one hand, and our general partner and its affiliates, on the other, are not and will not be the result of arm's-length negotiations;
- our partnership agreement permits us to distribute up to $35.0 million as operating surplus, even if it is generated from asset sales, non-working capital borrowings or other sources that would otherwise constitute capital surplus. This cash may be used to fund distributions to our general partner in respect of the general partner interest or our incentive distribution rights;
- our general partner determines which costs incurred by it and its affiliates are reimbursable by us;
- our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with its affiliates on our behalf;
- our general partner intends to limit its liability regarding our contractual and other obligations;
- our general partner may exercise its right to call and purchase common units if it and its affiliates own more than 80% of the common units;
- we may not choose to retain separate counsel for ourselves or for the holders of common units;
- our general partner's affiliates, including EQT and EQM, may compete with us and may offer business opportunities and/or sell midstream assets to other affiliates or third parties without first offering us the right to bid for them; and
- the holder or holders of our incentive distribution rights may elect to cause us to issue common units to it in connection with a resetting of incentive distribution levels without the approval of our unitholders, which may result in lower distributions to our common unitholders in certain situations.

Ongoing cost reimbursements due to our general partner and its affiliates for services provided, which will be determined by our general partner, may be substantial and will reduce our cash available for distribution to our unitholders.

Prior to making distributions on our common units, we will reimburse our general partner and its affiliates for all expenses they incur on our behalf. These expenses will include all costs incurred by our general partner and its affiliates in managing and operating us, including costs for rendering administrative staff and support services to us and reimbursements paid by our general partner to EQT for customary management and general administrative services. There is no limit on the amount of expenses for which our general partner and its affiliates may be reimbursed. Our partnership agreement provides that our general partner will determine the expenses that are allocable to us in good faith. In addition, under Delaware partnership law, our general partner has unlimited liability for our obligations, such as our debts and environmental liabilities, except for our contractual obligations that are expressly made without recourse to our general partner. To the extent our general partner incurs obligations on our behalf, we are obligated to reimburse or indemnify it. If we are unable or unwilling to reimburse or indemnify our general partner, our general partner may take actions to cause us to make payments of these obligations and liabilities. Any such payments could reduce the amount of cash otherwise available for distribution to our unitholders.

We expect to distribute a significant portion of our cash available for distribution to our partners, which could limit our ability to grow and/or make acquisitions.

We plan to distribute most of our cash available for distribution and will rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund our expansion capital expenditures and acquisitions, if any. As a result, to the extent we are unable to finance growth externally, our cash distribution policy may cause our growth to proceed at a slower pace than that of businesses that reinvest their cash to expand ongoing operations. To the extent we issue additional units in connection with any expansion capital expenditures or acquisitions, if any,

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the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. There are no limitations in our partnership agreement on our ability to issue additional units, including units ranking senior to the common units. In addition, the incurrence of commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which, in turn, may reduce the cash that we have available to distribute to our unitholders.

Our partnership agreement replaces our general partner's fiduciary duties to holders of our common units with contractual standards governing its duties.

Our partnership agreement contains provisions that eliminate and replace the fiduciary standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner, or otherwise, free of fiduciary duties to us and our unitholders other than the implied contractual covenant of good faith and fair dealing, which means that a court will enforce the reasonable expectations of the parties where the language in our partnership agreement does not provide for a clear course of action. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or our limited partners. Examples of decisions that our general partner may make in its individual capacity include:

- how to allocate business opportunities among us and its other affiliates, including EQT and EQM;
- whether to exercise its limited call right;
- whether to seek approval of the resolution of a conflict of interest by the conflicts committee of the board of directors of the general partner;
- how to exercise its voting rights with respect to any units it owns;
- whether to exercise its registration rights; and
- whether or not to consent to any merger or consolidation of the partnership or amendment to the partnership agreement.

Limited partners who own common units are treated as having consented to the provisions in the partnership agreement, including the provisions discussed above.

Our partnership agreement restricts the remedies available to holders of our common units for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that restrict the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty under state fiduciary duty law. For example, our partnership agreement:

- provides that whenever our general partner, the board of directors of our general partner or any committee thereof (including the conflicts committee) makes a determination or takes, or declines to take, any other action in their respective capacities, our general partner, the board of directors of our general partner and any committee thereof (including the conflicts committee) is required to make such determination, or take or decline to take such other action, in the absence of bad faith, and will not be subject to any other or different standard imposed by our partnership agreement, Delaware law, or any other law, rule or regulation, or at equity;
- provides that our general partner will not have any liability to us or our unitholders for decisions made in its capacity as a general partner so long as it acted in good faith, meaning that it believed that the decision was not adverse to the interest of our partnership;
- provides that our general partner and its officers and directors will not be liable for monetary damages to us, our limited partners or their assignees resulting from any act or omission unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our general partner or its officers and directors, as the case may be, acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal; and

- provides that our general partner will not be in breach of its obligations under the partnership agreement or its fiduciary duties to us or our unitholders if a transaction with an affiliate or the resolution of a conflict of interest is:
- approved by the conflicts committee of the board of directors of our general partner, although our general partner is not obligated to seek such approval; or
- approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner and its affiliates.

In connection with a situation involving a transaction with an affiliate or a conflict of interest, any determination by our general partner must be made in good faith. If an affiliate transaction or the resolution of a conflict of interest is not approved by our common unitholders or the conflicts committee and the board of directors of our general partner approves the affiliate transaction or resolution or course of action taken with respect to the conflict of interest, then it will be presumed that, in making its decision, the board of directors acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the partnership, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption and proving that such decision was not in good faith.

Our partnership agreement includes exclusive forum, venue and jurisdiction provisions. By purchasing a common unit, a limited partner is irrevocably consenting to these provisions regarding claims, suits, actions or proceedings and submitting to the exclusive jurisdiction of Delaware courts. Our partnership agreement also provides that any unitholder bringing an unsuccessful action will be obligated to reimburse us for any costs we have incurred in connection with such unsuccessful claim.

Our partnership agreement is governed by Delaware law. Our partnership agreement includes exclusive forum, venue and jurisdiction provisions designating Delaware courts as the exclusive venue for most claims, suits, actions and proceedings involving us or the officers, directors and employees of our general partner and its affiliates. If a dispute were to arise between a limited partner and us or the officers, directors or employees of our general partner and its affiliates, the limited partner may be required to pursue its legal remedies in Delaware, which may be an inconvenient or distant location and which is considered to be a more corporate-friendly environment. In addition, if any unitholder brings any of the aforementioned claims, suits, actions or proceedings and such person does not obtain a judgment on the merits that substantially achieves, in substance and amount, the full remedy sought, then such person shall be obligated to reimburse us and our affiliates for all fees, costs and expenses of every kind and description, including but not limited to all reasonable attorneys' fees and other litigation expenses, that the parties may incur in connection with such claim, suit, action or proceeding. Limited partners who own common units irrevocably consent to these provisions and potential reimbursement obligations regarding claims, suits, actions or proceedings and submitting to the exclusive jurisdiction of Delaware courts.

Holders of our common units have limited voting rights and are not entitled to elect our general partner or its directors, which could reduce the price at which our common units will trade.

Compared to the holders of common stock in a corporation, our unitholders have limited voting rights and, therefore, limited ability to influence management's decisions regarding our business. Our unitholders will have no right on an annual or ongoing basis to elect our general partner or its board of directors. The board of directors of our general partner, including the independent directors, is chosen entirely by EQT, as a result of it indirectly owning our general partner, and not by our unitholders. Furthermore, if our unitholders are dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. Unlike publicly-traded corporations, we will not conduct annual meetings of our unitholders to elect directors or conduct other matters routinely conducted at annual meetings of stockholders of corporations. As a result of these limitations, the price at which the common units trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

Our general partner intends to limit its liability regarding our obligations.

Our general partner intends to limit its liability under contractual arrangements between us and third parties so that the counterparties to such arrangements have recourse only against our assets, and not against our general partner or its assets. Our general partner may therefore cause us to incur indebtedness or other obligations that are nonrecourse to our general partner. Our partnership agreement provides that any action taken by our general partner to limit its liability is not a breach of our general partner's duties, even if we could have obtained more favorable terms without the limitation on liability. In addition, we are obligated to reimburse or indemnify our general partner to the extent that it incurs obligations on our behalf. Any such reimbursement or indemnification payments would reduce the amount of cash otherwise available for distribution to our unitholders.

Our general partner is required to deduct estimated maintenance capital expenditures from our operating surplus, which may result in less cash available for distribution to unitholders from operating surplus than if actual maintenance capital expenditures were deducted.

Maintenance capital expenditures are those capital expenditures made to maintain, over the long term, our operating capacity or operating income. Our partnership agreement requires our general partner to deduct estimated, rather than actual, maintenance capital expenditures from operating surplus in determining cash available for distribution from operating surplus. The amount of estimated maintenance capital expenditures deducted from operating surplus is subject to review and change by our general partner's board of directors at least once a year, provided that any change is approved by the conflicts committee of our general partner's board of directors. Our partnership agreement does not cap the amount of maintenance capital expenditures that our general partner may estimate. In years when our estimated maintenance capital expenditures are higher than actual maintenance capital expenditures, the amount of cash available for distribution to unitholders from operating surplus will be lower than if actual maintenance capital expenditures had been deducted from operating surplus. On the other hand, if our general partner underestimates the appropriate level of estimated maintenance capital expenditures, we will have more cash available for distribution from operating surplus in the short term but will have less cash available for distribution from operating surplus in future periods when we have to increase our estimated maintenance capital expenditures to account for the previous underestimation.

EQT may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to our incentive distribution rights, without the approval of the conflicts committee of our general partner's board of directors or the holders of our common units. This could result in lower distributions to holders of our common units.

EQT has the right, as the holder of our incentive distribution rights, at any time when it has received incentive distributions at the highest level to which it is entitled (50%) for the prior four consecutive fiscal quarters, to reset the initial target distribution levels at higher levels based on our distributions at the time of the exercise of the reset election. Following a reset election, the minimum quarterly distribution will be adjusted to equal the reset minimum quarterly distribution, and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution.

If EQT elects to reset the target distribution levels, it will be entitled to receive a number of common units. The number of common units to be issued to EQT will equal the number of common units that would have entitled EQT to an aggregate quarterly cash distribution in the quarter prior to the reset election equal to the distribution on the incentive distribution rights in the quarter prior to the reset election. We anticipate that EQT would exercise this reset right in order to facilitate acquisitions or internal growth projects that would not be sufficiently accretive to cash distributions per common unit without such conversion. It is possible, however, that EQT or a transferee could exercise this reset election at a time when it is experiencing, or expects to experience, declines in the cash distributions it receives related to its incentive distribution rights and may, therefore, desire to be issued common units rather than retain the right to receive incentive distributions based on the initial target distribution levels. This risk could be elevated if our incentive distribution rights have been transferred to a third party. As a result, a reset election may cause our common unitholders to experience a reduction in the amount of cash distributions that our common unitholders would have otherwise received had we not issued new common units to our general partner in connection with resetting the target distribution levels. EQT may transfer all or a portion of the incentive distribution rights in the future. After any such transfer, the holder or holders of a majority of our incentive distribution rights will be entitled to exercise the right to reset the target distribution levels.

The incentive distribution rights held by EQT may be transferred to a third party without unitholder consent.

EQT may transfer our incentive distribution rights to a third party at any time without the consent of our unitholders. If EQT transfers our incentive distribution rights to a third party but retains its ownership of our general partner interest, it may not have the same incentive to grow our partnership and increase quarterly distributions to unitholders over time as it would if it had retained ownership of our incentive distribution rights. For example, a transfer of incentive distribution rights by our general partner could reduce the likelihood of EQT selling or contributing additional midstream assets to us, as EQT would have less of an economic incentive to grow our business, which in turn would impact our ability to grow our asset base.

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

Control of our general partner may be transferred to a third party without unitholder consent.

Our general partner may transfer its general partner interest to a third party without the consent of our unitholders. Furthermore, our partnership agreement does not restrict the ability of the owners of our general partner from transferring all or a portion of their respective ownership interest in our general partner to a third party. The new owners of our general partner would then be in a position to replace the board of directors and officers of our general partner with its own choices and thereby exert significant control over the decisions made by the board of directors and officers. This effectively permits a "change of control" without the vote or consent of the unitholders.

We may issue additional units, including units that are senior to the common units, without unitholder approval, which would dilute our unitholders' existing ownership interests.

Our partnership agreement does not limit the number of additional limited partner interests that we may issue at any time without the approval of our unitholders. The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:

- each unitholder's proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- because the amount payable to holders of incentive distribution rights is based on a percentage of the total distributable cash flow, the distributions to holders of incentive distribution rights will increase even if the per unit distribution on common units remains the same;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

EQT may sell our common units in the public or private markets, which sales could have an adverse impact on the trading price of the common units.

As of February 15, 2018, EQT indirectly held 28,757,246 of our common units, representing a 28% limited partner interest in us. In addition, we have agreed to provide EQT with certain registration rights, pursuant to which we may be required to register common units it holds under the Securities Act and applicable state securities laws. Pursuant to the registration rights agreement and our partnership agreement, we may be required to undertake a future public or private offering of common units. The sale of these units in public or private markets could have an adverse impact on the price of the common units or on any trading market that may develop.

Our general partner has a limited call right that may require unitholders to sell their common units at an undesirable time or price.

If at any time our general partner and its affiliates (including EQT) own more than 80% of the common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price equal to the greater of (i) the average of the daily closing price of the common units over the 20 trading days preceding the date three days before notice of exercise of the call right is first mailed and (ii) the highest per-unit price paid by our general partner or any of its affiliates for common units during the 90-day period preceding the date such notice is first mailed. As a result, unitholders may be required to sell their common units at an undesirable time or price and may not receive any return or a negative return on their investment. Unitholders may also incur a tax liability upon a sale of their units. Our general partner is not obligated to obtain a fairness opinion regarding the value of the common units to be repurchased by it upon exercise of the limited call right. There is no restriction in our partnership agreement that prevents our general partner from issuing additional common units and exercising its call right. If our general partner exercised its limited call right, the effect would be to take us private and, if the units were subsequently deregistered, we would no longer be subject to the reporting requirements of the Securities Exchange Act of 1934, or the Exchange Act. As of February 15, 2018, our general partner and its affiliates (including EQT) owned 28% of our outstanding common units.

Our unitholders' liability may not be limited if a court finds that unitholder action constitutes control of our business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is

organized under Delaware law, and we currently own assets and conduct business in Pennsylvania and Ohio. A unitholder could be liable for any and all of our obligations as if that unitholder were a general partner if:

- a court or government agency determined that we were conducting business in a state but had not complied with that particular state's partnership statute; or
- a unitholder's right to act with other unitholders to remove or replace the general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitute "control" of our business.

Unitholders may have liability to repay distributions that were wrongfully distributed to them.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Act, we may not make a distribution to our unitholders if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of the impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Substituted limited partners are liable for the obligations of the assignor to make contributions to the partnership that are known to the substituted limited partner at the time it became a limited partner and for unknown obligations if the liabilities could be determined from the partnership agreement. Liabilities to partners on account of their partnership interest and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

The price of our common units may fluctuate significantly, and unitholders could lose all or part of their investment.

The market price of our common units may be influenced by many factors, some of which are beyond our control, including:

- our quarterly distributions;
- our quarterly or annual earnings or those of other companies in our industry;
- events affecting EQT and its affiliates;
- announcements by us or our competitors of significant contracts or acquisitions;
- changes in accounting standards, policies, guidance, interpretations or principles;
- general economic conditions;
- the failure of securities analysts to cover our common units or changes in financial estimates by analysts;
- future sales of our common units; and
- other factors described in these "Risk Factors."

The New York Stock Exchange (NYSE) does not require a publicly-traded partnership like us to comply with certain of its corporate governance requirements.

Our common units are currently traded on the NYSE. Because we are a publicly-traded partnership, the NYSE does not require us to have a majority of independent directors on our general partner's board of directors or to establish a compensation committee or a nominating and corporate governance committee. Accordingly, unitholders do not have the same protections afforded to certain corporations that are subject to all of the NYSE corporate governance requirements.

We incur increased costs as a result of being a publicly-traded partnership.

As a publicly-traded partnership, we incur significant legal, accounting and other expenses that we did not incur prior to our initial public offering (IPO). In addition, the Sarbanes-Oxley Act of 2002, as well as rules implemented by the SEC and the NYSE, require publicly-traded entities to adopt various corporate governance practices that will further increase our costs. Before we are able to make distributions to our unitholders, we must first pay or reserve cash for our expenses, including the costs of being a publicly-traded partnership. As a result, the amount of cash we have available for distribution to our unitholders is affected by the costs associated with being a publicly-traded partnership.

As a result of our IPO, we became subject to the public reporting requirements of the Exchange Act. We expect these rules and regulations to increase certain of our legal and financial compliance costs and to make activities more timeconsuming and costly. For example, as a result of becoming a publicly-traded partnership, we are required to have at least three independent directors, maintain an audit committee and adopt policies regarding internal controls and disclosure controls and procedures, including the preparation of reports on internal controls over financial reporting. In addition, we incur additional costs associated with our SEC reporting requirements.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as us not being subject to a material amount of entity-level taxation. If the IRS were to treat us as a corporation for federal income tax purposes, or if we become subject to entity-level taxation for state tax purposes, our cash available for distribution to our unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes.

Despite the fact that we are organized as a limited partnership under Delaware law, we would be treated as a corporation for U.S. federal income tax purposes unless we satisfy a "qualifying income" requirement. Based upon our current operations, we believe we satisfy the qualifying income requirement. We have requested and obtained a favorable private letter ruling from the IRS to the effect that, based on facts presented in the private letter ruling request, our income from the delivery of water and the collection, treatment, and transport of flowback, produced water, and other fluids constitutes "qualifying income" within the meaning of Section 7704 of the Internal Revenue Code of 1986, as amended (the Code). However, no ruling has been or will be requested regarding our treatment as a partnership for U.S. federal income tax purposes. Failing to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for U.S. federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay U.S. federal income tax on our taxable income at the corporate tax rate, which is currently 21.0%, and would likely pay state and local income tax at varying rates. Distributions to our unitholders would generally be taxed again as corporate dividends (to the extent of our current and accumulated earnings and profits), and no income, gains, losses or deductions would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, our cash available for distribution to our unitholders would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to the unitholders, likely causing a substantial reduction in the value of our common units.

Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for U.S. federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us. At the state level, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. Specifically, we currently own assets and conduct business in Pennsylvania and Ohio. Imposition of a similar tax on us in other jurisdictions that we may expand to could substantially reduce our cash available for distribution to our unitholders.

The tax treatment of publicly traded partnerships or an investment in our units could be subject to potential legislative, judicial or administrative changes or differing interpretations, possibly applied on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. From time to time, members of Congress propose and consider substantive changes to the existing U.S. federal income tax laws that affect publicly traded partnerships.

Any modification to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible for us to meet the exception for us to be treated as a partnership for U.S. federal income tax purposes. We are unable to predict whether any of these changes will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

Our unitholders are required to pay income taxes on their share of our taxable income even if they do not receive any cash distributions from us. A unitholder's share of our taxable income, and its relationship to any distributions we make, may be affected by a variety of factors, including our economic performance, transactions in which we engage or changes in law and may be substantially different from any estimate we make in connection with a unit offering.

A unitholder’s allocable share of our taxable income will be taxable to such unitholder, which may require the unitholder to pay federal income taxes and, in some cases, state and local income taxes, even if the unitholder receives cash distributions from us that are less than the actual tax liability that results from that income or no cash distributions at all.

A unitholder’s share of our taxable income, and its relationship to any distributions we make, may be affected by a variety of factors, including our economic performance, which may be affected by numerous business, economic, regulatory, legislative, competitive and political uncertainties beyond our control, and certain transactions in which we might engage. For example, we may engage in transactions that produce substantial taxable income allocations to some or all of our unitholders without a corresponding increase in cash distributions to our unitholders, such as a sale or exchange of assets, the proceeds of which are reinvested in our business or used to reduce our debt, or an actual or deemed satisfaction of our indebtedness for an amount less than the adjusted issue price of the debt. A unitholder’s ratio of its share of taxable income to the cash received by it may also be affected by changes in law. For instance, under the recently enacted law known as the Tax Cuts and Jobs Act of 2017, the net interest expense deductions of certain business entities, including us, are limited to 30% of such entity’s “adjusted taxable income,” which is generally taxable income with certain modifications. If the limit applies, a unitholder’s taxable income allocations will be more (or its net loss allocations will be less) than would have been the case absent the limitation.

From time to time, in connection with an offering of our common units, we may state an estimate of the ratio of federal taxable income to cash distributions that a purchaser of our common units in that offering may receive in a given period. These estimates depend in part on factors that are unique to the offering with respect to which the estimate is stated, so the expected ratio applicable to other common units will be different, and in many cases less favorable, than these estimates. Moreover, even in the case of common units purchased in the offering to which the estimate relates, the estimate may be incorrect, due to the uncertainties described above, challenges by the IRS to tax reporting positions which we adopt, or other factors. The actual ratio of taxable income to cash distributions could be higher or lower than expected, and any differences could be material and could materially affect the value of our common units.

If the IRS were to contest the federal income tax positions we take, it may adversely impact the market for our common units, and the costs of any such contest would reduce cash available for distribution to our unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a Partnership for U.S. federal income tax purposes. The IRS may adopt positions that differ from the conclusions of our counsel expressed in a prospectus or from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel’s conclusions or the positions we take. A court may not agree with some or all of our counsel’s conclusions or positions we take. Any contest with the IRS, and the outcome of any IRS contest, may materially and adversely impact the market for our common units and the price at which they trade. Moreover, the costs of any contest between us and the IRS will result in a reduction in cash available for distribution to our unitholders and thus will be borne indirectly by our unitholders.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after 2017, it (and some states) may assess and collect any resulting taxes (including any applicable penalties and interest) directly from us, in which case we may require our unitholders and former unitholders to reimburse us for such taxes (including any applicable penalties or interest) or, if we are required to bear such payment, our cash available for distribution to our unitholders might be substantially reduced.

Pursuant to the Bipartisan Budget Act of 2015, if the IRS makes audit adjustments to our income tax returns for tax years beginning after 2017, it (and some states) may assess and collect any resulting taxes (including any applicable interest and penalties) directly from us. We will generally have the ability to shift any such tax liability to our general partner and our unitholders in accordance with their interests in us during the year under audit, but there can be no assurance that we will be able to do so (or will choose to do so) under all circumstances, or that we will be able to (or choose to) effect corresponding shifts in state income or similar tax liability resulting from the IRS adjustment in states in which we do business in the year under audit or in the adjustment year. If we make payments of taxes, penalties and interest resulting from audit adjustments, we may require our unitholders and former unitholders to reimburse us for such taxes (including any applicable penalties or interest) or, if we are required to bear such payment, our cash available for distribution to our unitholders might be substantially reduced.

In the event the IRS makes an audit adjustment to our income tax returns and we do not or cannot shift the liability to our unitholders in accordance with their interests in us during the year under audit, we will generally have the ability to request that the IRS reduce the determined underpayment by reducing the suspended passive loss carryovers of our unitholders (without any compensation from us to such unitholders), to the extent such underpayment is attributable to a net decrease in passive activity losses allocable to certain partners. Such reduction, if approved by the IRS, will be binding on any affected unitholders.

Tax gain or loss on disposition of our common units could be more or less than expected.

If our unitholders sell their common units, our unitholders will recognize a gain or loss equal to the difference between the amount realized and their tax basis in those common units. Because distributions in excess of our unitholders' allocable share of our net taxable income decrease their tax basis in their common units, the amount, if any, of such prior excess distributions with respect to the units our unitholders sell will, in effect, become taxable income to our unitholders if they sell such units at a price greater than their tax basis in those units, even if the price our unitholders receive is less than their original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder's share of our nonrecourse liabilities, if our unitholders sell their common units, our unitholders may incur a tax liability in excess of the amount of cash they receive from the sale.

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

Investment in common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (IRAs), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Allocations and/or distributions to non-U.S. persons will be subject to withholding taxes imposed at the highest effective tax rate applicable to such non-U.S. persons, and each non-U.S. person will be required to file United States federal tax returns and pay tax on their share of our taxable income.

Under the recently enacted tax reform law, if a unitholder sells or otherwise disposes of a common unit, the transferee is required to withhold 10.0% of the amount realized by the transferor unless the transferor certifies that it is not a foreign person, and we are required to deduct and withhold from the transferee amounts that should have been withheld by the transferee but were not withheld. However, the Department of the Treasury and the IRS have determined that this withholding requirement should not apply to any disposition of a publicly traded interest in a publicly traded partnership (such as us) until regulations or other guidance have been issued clarifying the application of this withholding requirement to dispositions of interests in publicly traded partnerships. Accordingly, while this new withholding requirement does not currently apply to interests in us, there can be no assurance that such requirement will not apply in the future.

Tax-exempt entities and non-U.S. persons should consult a tax advisor before investing in our common units.

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

Because we cannot match transferors and transferees of our common units and because of other reasons, we will adopt depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to you. It also could affect the timing of these tax benefits or the amount of gain from your sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to your tax returns.

We generally prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We generally prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month (the Allocation Date), instead of on the basis of the date a particular unit is transferred. Similarly, we generally allocate certain deductions for depreciation of capital additions, gain or loss realized on a sale or other disposition of our assets and, in the discretion of the general partner, any other extraordinary item of income, gain, loss or deduction based upon ownership on the Allocation Date. The U.S. Department of the Treasury adopted final Treasury Regulations allowing a similar monthly simplifying convention, but such regulations do not specifically authorize all aspects of our proration method. If the IRS were to challenge our proration method, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder who disposes of units prior to the record date set for a cash distribution for that quarter will be allocated items of our income, gain, loss and deduction attributable to the month of disposition but will not be entitled to receive a cash distribution for that period.

A unitholder whose units are the subject of a securities loan (e.g., a loan to a "short seller" to cover a short sale of units) may be considered to have disposed of those units. If so, the unitholder would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and could recognize gain or loss from the disposition.

Because there are no specific rules governing the U.S. federal income tax consequence of loaning a partnership interest, a unitholder whose units are the subject of a securities loan may be considered to have disposed of the loaned units. In that case, the unitholder may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a securities loan are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

We have adopted certain valuation methodologies in determining unitholder’s allocations of income, gain, loss and deduction. The IRS may challenge these methods or the resulting allocations, and such a challenge could adversely affect the value of our common units.

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

A successful IRS challenge to these methods or allocations could adversely affect the amount, character, and timing of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders’ sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders’ tax returns without the benefit of additional deductions.

As a result of investing in our common units, our unitholders may become subject to state and local taxes and income tax return filing requirements in jurisdictions where they do not live.

In addition to U.S. federal income taxes, our unitholders may be subject to other taxes, including foreign, state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if they do not live in any of those jurisdictions. Our unitholders will likely be required to file foreign, state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements.

We currently own assets and conduct business in Pennsylvania and Ohio, each of which imposes a personal income tax on individuals. As we make acquisitions or expand our business, we may own assets or conduct business in additional states that impose a personal income tax. It is our unitholders responsibility to file all United States federal, foreign, state and local tax returns.

Compliance with and changes in tax laws could adversely affect our performance.

We are subject to extensive tax laws and regulations, including federal, state and foreign income taxes and transactional taxes such as excise, sales/use, payroll, franchise and ad valorem taxes. New tax laws and regulations and changes in existing tax laws and regulations are continuously being enacted that could result in increased tax expenditures in the future. Many of these tax liabilities are subject to audits by the respective taxing authority. These audits may result in additional taxes as well as interest and penalties.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

The information required by Item 2 is contained in “Item 1. Business”.

Item 3. Legal Proceedings

In the ordinary course of business, various legal and regulatory claims and proceedings are pending or threatened against us. While the amounts claimed may be substantial, we are unable to predict with certainty the ultimate outcome of such claims and proceedings. We accrue legal and other direct costs related to loss contingencies when actually incurred. We have established reserves we believe to be appropriate for pending matters and, after consultation with counsel and giving

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appropriate consideration to available insurance, we believe that the ultimate outcome of any matter currently pending against us will not materially affect our business, financial condition, results of operations, liquidity or ability to make distributions.

Environmental Proceedings

We received a number of notices of violation (NOVs) from environmental agencies in the states in which we operate alleging various violations of oil and gas, air, water and/or waste regulations. We have responded to these NOVs and have, where applicable, substantially corrected or remediated the activities in question. We dispute the facts alleged in some of the NOVs and cannot predict with certainty whether any or all of these NOVs will result in penalties. If penalties are imposed, an individual penalty or the aggregate of these penalties could result in monetary sanctions in excess of $100,000.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

Item 5. Market for Registrant's Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities
Our common units are listed on the New York Stock Exchange (NYSE) under the symbol RMP. The following table sets forth the high and low sales prices reflected in the NYSE Composite Transactions of the common units, as reported by the NYSE, as well as the amount of cash distributions declared per quarter for 2017 and 2016.

	2017			2016		
	Unit Price Range		Distributions paid per	Unit Price Range		Distributions paid per
(in dollars per share)	High	Low	Common Unit	High	Low	Common Unit
1st Quarter	$26.42	$22.48	$ 0.2505	$15.39	$8.40	$ 0.1965
2nd Quarter	$26.18	$16.87	$ 0.2608	$20.65	$14.21	$ 0.2100
3rd Quarter	$21.50	$19.52	$ 0.2711	$24.30	$18.05	$ 0.2235
4th Quarter	$21.99	$19.69	$ 0.2814	$24.88	$20.05	$ 0.2370

On January 18, 2018, the Board of Directors of our general partner declared a cash distribution to our unitholders of $0.2917 per common and subordinated unit for the fourth quarter of 2017. The cash distribution was paid on February 14, 2018, to unitholders of record at the close of business on February 2, 2018. Also on February 14, 2018, a cash distribution of $3.0 million was made to GP Holdings related to its IDRs in the Partnership based upon the level of distribution paid per common and subordinated unit.
The number of unitholders of record of our common units was approximately 89 as of January 31, 2018. The number of registered holders does not include holders that have common units held for them in "street name," meaning that the common units are held for their accounts by a broker or other nominee. In these instances, the brokers or other nominees are included in the number of registered holders, but the underlying unitholders that have units are not.
We also issued 28,753,623 subordinated units, which were converted to common units on a one-for-one basis on February 15, 2018. Prior to the conversion, all of the subordinated units were held by GP Holdings. GP Holdings received quarterly distributions on these units only after sufficient distributions had been paid to the holders of common units. Please see Note 7 to the Consolidated Financial Statements for a discussion of the conversion of the subordinated units.
Please see Note 7 to the Consolidated Financial Statements included in this Annual Report for information on the significant provisions of our partnership agreement that relate to distributions of available cash, minimum quarterly distributions and IDRs.

The information relating to our equity compensation plans required by Item 5 is included in Item 12, "Security Ownership of Certain Beneficial Owners and Management" of this Annual Report which is incorporated herein by reference.
We did not repurchase any of our common units during the year ended December 31, 2017.

Item 6. Selected Financial Data

In connection with the completion of the Mergers, EQT acquired indirect ownership of our general partner resulting in a change of control of our general partner. As a result of the change in control, our assets and liabilities were adjusted to fair value on the Merger Date by application of pushdown accounting and we became a consolidated subsidiary of EQT. Due to the application of pushdown accounting, our consolidated financial statements and certain footnote disclosures are presented in two distinct periods to indicate the application of two different bases of accounting between the periods presented. The periods prior to the Merger Date are identified as Predecessor, and the period from the Merger Date forward is identified as Successor. The following table presents our selected financial and operating data as of the dates and for the periods indicated and should be read in conjunction with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and the Consolidated Financial Statements and related notes, each of which is included in this Annual Report. We believe that the assumptions underlying the preparation of our historical consolidated financial statements are reasonable.

	Successor	Predecessor				
			Years Ended December 31,			
(in thousands, except per unit data)	Period from November 13, 2017 to December 31, 2017	Period from January 1, 2017 to November 12, 2017	2016 [2]	2015	2014	2013
Statement of operations data:						
Total operating revenues	$44,219	$250,474	$201,623	$114,459	$6,448	$498
Operating income (loss)	$25,945	$163,478	$126,942	$62,036	$(30,567)	$(5,208)
Net income (loss)	$25,134	$152,839	$121,610	$52,495	$(31,328)	$(9,012)
Limited partner net income	$23,535	$146,657	$120,182	$45,199	$1,162	
Net income attributable to RMP per limited partner unit[1]						
Common units (basic)	$0.23	$1.43	$1.46	$0.76	$0.02	
Common units (diluted)	$0.23	$1.43	$1.45	$0.76	$0.02	
Subordinated units (basic & diluted)	$0.23	$1.43	$1.50	$0.76	$0.02	
Cash distributions paid per limited partner unit[1]	$0.281	$0.782	$0.867	$0.592	$—	
Balance sheet data (at period end):						
Total assets	$2,849,013		$1,399,217	$689,790	$443,091	$74,445
Revolving credit facility	$286,000		$190,000	$143,000	$—	$—
Net cash provided by (used in):						
Operating activities	$22,430	$150,811	$154,117	$70,006	$(25,021)	$(7,186)
Investing activities	$(34,553)	$(131,421)	$(721,087)	$(379,991)	$(336,273)	$(44,244)
Financing activities	$9,959	$(28,522)	$581,207	$290,748	$387,980	$51,578

(1) Net income per limited partner unit and cash distributions per limited partner unit are presented only for the periods subsequent to our initial public offering (IPO) and do not include results attributable to the Water Assets (defined in Note 1 to the Consolidated Financial Statements included in this Annual Report) prior to their acquisition as these results are not attributable to limited partners of the Partnership.

(2) Includes post-acquisition results of the Vantage Midstream Entities. Please see Note 2 to the Consolidated Financial Statements included in this Annual Report for further detail regarding the Vantage Midstream Asset Acquisition.

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and related notes included in Item 8 of this Annual Report. As a result of the Mergers, our assets and liabilities were adjusted to fair value by application of pushdown accounting and we became a consolidated subsidiary of EQT. Due to the application of pushdown accounting, our consolidated financial statements and certain footnote disclosures are in two distinct periods to indicate the application of two different bases of accounting between the periods presented. The periods prior to the Merger Date are identified as Predecessor and the period from the Merger Date forward is identified as Successor. For discussion purposes, we have combined the results of operations for the Successor and Predecessor periods of 2017 because we believe it facilitates the comparison of 2016 and 2015 operating and financial performance to 2017 and because our operations have not changed as a result of the Mergers.

Executive Overview

We reported net income of $178.0 million in the Combined Year 2017 compared with $121.6 million in 2016. The increase primarily resulted from higher revenues from both gathering and water services, partially offset by an increase in operating expenses consistent with the growth of the business and higher interest expense.

We reported net income of $121.6 million in 2016 compared with $52.5 million in 2015. The increase primarily resulted from higher revenues from both gathering and water services, partially offset by an increase in operating expenses consistent with the growth of the business and higher interest expense.

We declared a cash distribution to our unitholders of $0.2917 per unit on January 18, 2018, which was 4% higher than the third quarter 2017 distribution of $0.2814 per unit and 16% higher than the fourth quarter 2016 distribution of $0.2505 per unit. Total distributions related to 2017 were $1.105 per unit compared to $0.921 per unit total distributions related to 2016, a 20% increase.

Results of Operations

The following table sets forth consolidated operating data for the Combined Year ended December 31, 2017 compared to the year ended December 31, 2016 and for the year ended December 31, 2016 compared to the year ended December 31, 2015:

	Successor	Predecessor	(Unaudited) Combined Year	Predecessor		Predecessor	
	Period from November 13, 2017 to December 31, 2017	Period from January 1, 2017 to November 12, 2017	Year Ended December 31, 2017	Year Ended December 31, 2016	Change	Year Ended December 31, 2015	Change
Statement of operations: (in thousands)							
Operating revenues:							
Affiliate	$ 44,134	$ 203,642	$ 247,776	$ 152,260	$ 95,516	$ 93,668	$ 58,592
Third-party	85	46,832	46,917	49,363	(2,446)	20,791	28,572
Total operating revenues	44,219	250,474	294,693	201,623	93,070	114,459	87,164
Operating expenses:							
Operation and maintenance expense	7,182	33,768	40,950	24,608	16,342	14,910	9,698
General and administrative expense	3,612	22,252	25,864	21,613	4,251	17,895	3,718
Incentive unit expense	—	—	—	—	—	1,044	(1,044)
Depreciation expense	7,480	26,420	33,900	25,170	8,730	16,399	8,771
Acquisition costs	—	529	529	125	404	—	125
Amortization of intangible assets	—	1,413	1,413	1,634	(221)	1,632	2
Other expense	—	2,614	2,614	1,531	1,083	543	988
Total operating expenses	18,274	86,996	105,270	74,681	30,589	52,423	22,258
Operating income (loss)	25,945	163,478	189,423	126,942	62,481	62,036	64,906
Other income (expense)	15	56	71	78	(7)	11	67
Interest expense	(826)	(7,053)	(7,879)	(3,931)	(3,948)	(3,164)	(767)
Amortization of deferred financing costs	—	(3,642)	(3,642)	(1,479)	(2,163)	(576)	(903)
Income (loss) before income taxes	25,134	152,839	177,973	121,610	56,363	58,307	63,303
Income tax expense	—	—	—	—	—	(5,812)	5,812
Net income	$ 25,134	$ 152,839	$ 177,973	$ 121,610	$ 56,363	$ 52,495	$ 69,115

Combined Year Ended December 31, 2017 Compared to the Year Ended December 31, 2016

The factors impacting operating income are discussed in the business segment results.

Interest expense. Interest expense increased from $3.9 million for the year ended December 31, 2016 to $7.9 million for the Combined Year ended December 31, 2017, an increase of $4.0 million, or 100%. The increase in interest expense was primarily due to the timing of draw-downs on our revolving credit facility. The average borrowing under our revolving credit facility for the Combined Year ended December 31, 2017 and the year ended December 31, 2016 was $216.3 million and $110.0 million, respectively.

Amortization of deferred financing costs. Amortization of deferred financing costs increased from $1.5 million for the year ended December 31, 2016 to $3.6 million for the period from January 1, 2017 through November 12, 2017, an

increase of $2.2 million, or 140%. The increase primarily related to the timing financing costs incurred associated with equity offerings and amendments to our revolving credit facility. At the Merger Date, the Predecessor's deferred financing costs were eliminated through the application of pushdown accounting resulting in no amortization for the Successor period.
Year Ended December 31, 2016 Compared to the Year Ended December 31, 2015
The factors impacting operating income are discussed in the business segment results.
Interest expense. Interest expense increased from $3.2 million for the year ended December 31, 2015 to $3.9 million for the year ended December 31, 2016, an increase of $0.8 million. For the year ended December 31, 2015, we incurred interest expense of $2.4 million in connection with our revolving credit facility and the Water Assets were allocated $0.8 million of interest expense by Rice Energy. For the year ended December 31, 2016, the full amount of interest expense incurred related to

borrowing under our revolving credit facility. Our average borrowing under our revolving credit facility for the years ended December 31, 2016 and 2015 was $110.0 million and $46.9 million, respectively.

Amortization of deferred financing costs. Amortization of deferred financing costs increased from $0.6 million for the year ended December 31, 2015 to $1.5 million for the year ended December 31, 2016, an increase of $0.9 million, or 157%. The increase primarily related to the timing of financing costs incurred associated with equity offerings and amendments to our revolving credit facility.

Income tax expense. The $5.8 million income tax expense for the year ended December 31, 2015 was allocated to the Water Assets prior to their acquisition by Rice Energy. Following our initial public offering, we are not subject to U.S. federal income tax and certain state income taxes due to our status as a partnership.

Business Segment Results of Operations

We operate in two business segments: (i) gathering and compression and (ii) water services. The gathering and compression segment provides natural gas gathering and compression services for EQT and third parties in the Appalachian Basin. The water services segment is engaged in the provision of water services to support well completion activities and to collect and recycle or dispose of flowback and produced water for EQT and third parties in the Appalachian Basin.

We evaluate our business segments on their contribution to our consolidated results based on operating income. Please see Note 10 to the Consolidated Financial Statements included in the Annual Report for a reconciliation of each segment's operating income to our consolidated operating income.

The following tables set forth selected segment financial data and certain operating data for the Combined Year ended December 31, 2017 compared to the year ended December 31, 2016 and for the year ended December 31, 2016 compared to the year ended December 31, 2015:

Gathering and Compression Segment

	Successor	Predecessor	(Unaudited) Combined Year	Predecessor		Predecessor	
Financial data: (in thousands)	Period from November 13, 2017 to December 31, 2017	Period from January 1, 2017 to November 12, 2017	Year Ended December 31, 2017	Year Ended December 31, 2016	Change	Year Ended December 31, 2015	Change
Gathering revenues:							
Affiliate	$ 26,242	$ 110,594	$ 136,836	$ 77,625	$59,211	$ 59,734	$17,891
Third-party	19	34,136	34,155	38,669	(4,514)	15,980	22,689
Total gathering revenues	26,261	144,730	170,991	116,294	54,697	75,714	40,580
Compression revenues:							
Affiliate	4,343	16,031	20,374	8,722	11,652	1,445	7,277
Third-party	10	6,731	6,741	7,083	(342)	52	7,031
Total compression revenues	4,353	22,762	27,115	15,805	11,310	1,497	14,308
Total operating revenues	30,614	167,492	198,106	132,099	66,007	77,211	54,888
Operating expenses:							
Operation and maintenance expense	1,584	11,939	13,523	8,000	5,523	6,006	1,994
General and administrative expense	3,265	18,944	22,209	17,301	4,908	13,886	3,415
Depreciation expense	3,965	11,324	15,289	10,840	4,449	6,310	4,530
Acquisition costs	—	529	529	125	404	—	125

Amortization of intangible assets	—	1,413	1,413	1,634	(221)	1,632	2
Other expense	—	2,594	2,594	1,051	1,543	492	559
Total operating expenses	8,814	46,743	55,557	38,951	16,606	28,326	10,625
Operating income	$ 21,800	$ 120,749	$ 142,549	$ 93,148	$49,401	$ 48,885	$44,263

Combined Year Ended December 31, 2017 Compared to the Year Ended December 31, 2016

Operating revenues. Revenues from gathering and compression of natural gas increased from $132.1 million for the year ended December 31, 2016 to $198.1 million for the Combined Year ended December 31, 2017, an increase of $66.0 million, or 50%. The increase in operating revenues primarily relates to increased gathering and compression revenues associated with a

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43% and 67% increase in period over period gathering and compression throughput, respectively. Post-acquisition gathering and compression revenues from the Vantage Midstream Entities increased from $6.3 million for the year ended December 31, 2016 to $46.5 million for the Combined Year ended December 31, 2017.

	Year Ended December 31,		Change	%
Operating data:	2017	2016		
Gathering volumes: (in BBtu/d)				