USA Compression Partners, LP
Form 10-K
February 13, 2018
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

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: 001-35779

USA Compression Partners, LP

(Exact Name of Registrant as Specified in its Charter)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	75-2771546 (I.R.S. Employer Identification No.)

100 Congress Avenue, Suite 450 Austin, TX (Address of Principal Executive Offices)	 78701 (Zip Code)

(512) 473-2662

(Registrant's telephone number, including area code)

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. Yes 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 No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the 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.

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

Large accelerated filer	Accelerated filer
Non-accelerated filer (Do not check if a smaller reporting company)	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 No

The aggregate market value of common units held by non-affiliates of the registrant (treating directors and executive officers of the registrant's general partner and holders of 5% or more of the common units outstanding, for this purpose, as if they were affiliates of the registrant) as of June 30, 2017, the last business day of the registrant's most recently completed second fiscal quarter was $369,969,262. This calculation does not reflect a determination that such persons are affiliates for any other purpose.

As of February 8, 2018, there were 62,194,405 common units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE: NONE

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PART I

DISCLOSURE REGARDING FORWARD-LOOKING STATEMENTS

This report contains "forward-looking statements." All statements other than statements of historical fact contained in this report are forward-looking statements, including, without limitation, statements regarding our plans, strategies, prospects and expectations concerning our business, results of operations and financial condition. You can identify many of these statements by looking for words such as "believe," "expect," "intend," "project," "anticipate," "estimate," "conti or similar words or the negative thereof.

Known material factors that could cause our actual results to differ from those in these forward-looking statements are described below, in Part I, Item 1A ("Risk Factors") and in Part II, Item 7 ("Management's Discussion and Analysis of Financial Condition and Results of Operations"). Important factors that could cause our actual results to differ materially from the expectations reflected in these forward-looking statements include, among other things:

- changes in general economic conditions and changes in economic conditions of the crude oil and natural gas industry specifically;
- competitive conditions in our industry;
- changes in the long-term supply of and demand for crude oil and natural gas;
- our ability to realize the anticipated benefits of acquisitions and to integrate the acquired assets with our existing fleet, including the CDM Acquisition (as defined below);
- actions taken by our customers, competitors and third-party operators;
- the deterioration of the financial condition of our customers;
- changes in the availability and cost of capital;
- operating hazards, natural disasters, weather-related delays, casualty losses and other matters beyond our control;

- the effects of existing and future laws and governmental regulations;
- the effects of future litigation; and
- the failure to consummate the CDM Acquisition.

All forward-looking statements included in this report are based on information available to us on the date of this report and speak only as of the date of this report. Except as required by law, we undertake no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, future events or otherwise. All subsequent written and oral forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the foregoing cautionary statements.

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ITEM 1.Business

References in this report to "USA Compression," "we," "our," "us," "the Partnership" or like terms refer to USA Compression Partners, LP and its wholly owned subsidiaries, including USA Compression Partners, LLC ("USAC Operating") and USAC OpCo 2, LLC ("OpCo 2" and, together with USAC Operating, the "Operating Subsidiaries"). References to our "general partner" refer to USA Compression GP, LLC. References to "USA Compression Holdings" refer to USA Compression Holdings, LLC, the owner of our general partner. References to "USAC Management" refer to USA Compression Management Services, LLC, a wholly owned subsidiary of our general partner. References to "Riverstone" refer to Riverstone/Carlyle Global Energy and Power Fund IV, L.P., and affiliated entities, including Riverstone Holdings, LLC.

Overview

We are a growth-oriented Delaware limited partnership and we believe that we are one of the largest independent providers of compression services in the United States ("U.S.") in terms of total compression fleet horsepower. We have been providing compression services since 1998 and completed our initial public offering in January 2013. As of December 31, 2017, we had 1,799,781 horsepower in our fleet and 153,020 horsepower on order for expected delivery during 2018 and 2019. We provide compression services to our customers primarily in connection with infrastructure applications, including both allowing for the processing and transportation of natural gas through the domestic pipeline system and enhancing crude oil production through artificial lift processes. As such, our compression services play a critical role in the production, processing and transportation of both natural gas and crude oil.

We provide compression services in a number of shale plays throughout the U.S., including the Utica, Marcellus, Permian Basin, Delaware Basin, Eagle Ford, Mississippi Lime, Granite Wash, Woodford, Barnett, Haynesville, Niobrara and Fayetteville shales. The demand for our services is driven by the domestic production of natural gas and crude oil; as such, we have focused our activities in areas with attractive natural gas and crude oil production growth, which are generally found in these shale and unconventional resource plays. According to studies promulgated by the Energy Information Agency ("EIA"), the production and transportation volumes in these shale plays are expected to increase over the long term due to the comparatively attractive economic returns versus returns achieved in many conventional basins. Furthermore, the changes in production volumes and pressures of shale plays over time require a wider range of compression services than in conventional basins. We believe we are well positioned to meet these changing operating conditions due to the flexibility of our compression units. While our business focuses largely on compression services serving infrastructure applications, including centralized natural gas gathering systems and processing facilities, which utilize large horsepower compression units, typically in shale plays, we also provide compression services in more mature conventional basins, including gas lift applications on crude oil wells targeted by horizontal drilling techniques. Gas lift, a process by which natural gas is injected into the production tubing of an existing producing well, thus reducing the hydrostatic pressure and allowing the oil to flow at a higher rate, and other artificial lift technologies are critical to the enhancement of production of oil from horizontal wells operating in tight shale plays.

We operate a modern fleet of compression units, with an average age of approximately five years. We acquire our compression units from third-party fabricators who build the units to our specifications, utilizing specific components from original equipment manufacturers and assembling the units in a manner that provides us the ability to meet certain operating condition thresholds. Our standard new-build compression units are generally configured for multiple compression stages allowing us to operate our units across a broad range of operating conditions. The design flexibility of our units, particularly in midstream applications, allows us to enter into longer-term contracts and reduces the redeployment risk of our horsepower in the field. Our modern and standardized fleet, decentralized field level operating structure and technical proficiency in predictive and preventive maintenance and overhaul operations have enabled us to achieve average service run times consistently at or above the levels required by our customers.

As part of our services, we engineer, design, operate, service and repair our compression units and maintain related support inventory and equipment. The compression units in our modern fleet are designed to be easily adaptable to fit our customers' changing compression requirements. Focusing on the needs of our customers and providing them with reliable and flexible compression services in geographic areas of attractive growth helps us to generate stable cash flows for our unitholders.

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We provide compression services to our customers under fixed-fee contracts with initial contract terms typically between six months and five years, depending on the application and location of the compression unit. We typically continue to provide compression services at a specific location beyond the initial contract term, either through contract renewal or on a month-to-month or longer basis. We primarily enter into take-or-pay contracts whereby our customers are required to pay our monthly fee even during periods of limited or disrupted throughput, which enhances the stability and predictability of our cash flows. We are not directly exposed to commodity price risk because we do not take title to the natural gas or crude oil involved in our services and because the natural gas used as fuel by our compression units is supplied by our customers without cost to us.

We provide compression services to major oil companies and independent producers, processors, gatherers and transporters of natural gas and crude oil. Regardless of the application for which our services are provided, our customers rely upon the availability of the equipment used to provide compression services and our expertise to help generate the maximum throughput of product, reduce fuel costs and minimize emissions. While we are currently focused on our existing service areas, our customers may have compression demands in other areas of the U.S. in conjunction with their field development projects. We continually consider expansion of our areas of operation in the U.S. based upon the level of customer demand. Our modern, flexible fleet of compression units, which have been designed to be rapidly deployed and redeployed throughout the country, provides us with opportunities to expand into other areas with both new and existing customers.

Our assets and operations are organized into a single reportable segment and are all located and conducted in the U.S. See our consolidated financial statements, and the notes thereto, included elsewhere in this report for financial information on our operations and assets; such information is incorporated herein by reference.

Recent Developments

On January 15, 2018, we entered into a Contribution Agreement (the “Contribution Agreement”) with Energy Transfer Partners, L.P. (“ETP”), Energy Transfer Partners GP, L.P., the general partner of ETP (“ETP GP”), ETC Compression, LLC (“ETC” and, together with ETP and ETP GP, the “Contributors”) and, solely for certain purposes therein, Energy Transfer Equity, L.P. (“ETE” and together with ETP, the “Energy Transfer Parties”), pursuant to which, among other things, ETP will contribute to us, and we will acquire from ETP, all of the issued and outstanding membership interests of CDM Resource Management LLC (“CDM Management”) and CDM Environmental & Technical Services LLC (“CDM E&T” and, together with CDM Management, “CDM”) for aggregate consideration of approximately $1.7 billion consisting of units representing limited partner interests in the Partnership and an amount in cash equal to $1.225 billion, subject to certain adjustments (the “CDM Acquisition”).

The CDM Acquisition is expected to close in the first half of 2018, subject to customary closing conditions, including (i) the concurrent closing of the GP Purchase (as defined below), and (ii) the transactions contemplated by the Equity Restructuring Agreement (as defined below), including the Restructuring (as defined below), shall be able to be consummated immediately following the Closing (as defined below), and as otherwise described in the Contribution Agreement (the “Closing”).

On January 15, 2018, and in connection with the execution of the Contribution Agreement, ETE entered into a Purchase Agreement (the “GP Purchase Agreement”) with Energy Transfer Partners, L.L.C. (together with ETE, the “GP Purchasers”), USA Compression Holdings, and, solely for certain purposes therein, R/C IV USACP Holdings, L.P. and ETP, pursuant to which the GP Purchasers will acquire from USA Compression Holdings (i) all of the outstanding limited liability company interests in our general partner, and (ii) 12,466,912 common units (the “GP Purchase”).

On January 15, 2018, and in connection with the execution of the Contribution Agreement, we entered into an Equity Restructuring Agreement (the “Equity Restructuring Agreement”) with our general partner and ETE, pursuant to which, among other things, we, our general partner and ETE have agreed to cancel our incentive distribution rights (the “Cancellation”) and convert our General Partner Interest (as defined in the Equity Restructuring Agreement) into a non-economic general partner interest (the “Conversion” and, together with the Cancellation, the “Restructuring”), in exchange for our issuance of 8,000,000 common units to the general partner, effective at the Closing.

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On January 15, 2018, we entered into a Series A Preferred Unit and Warrant Purchase Agreement (the “Series A Purchase Agreement”) with certain investment funds managed or sub-advised by EIG Global Energy Partners (“EIG”) and other investment vehicles unaffiliated with EIG (collectively, the “Purchasers”) to issue and sell in a private placement (the “Private Placement”) $500 million in the aggregate of (i) newly authorized and established Series A Perpetual Preferred Units representing limited partner interests in the Partnership (the “Preferred Units”) and (ii) warrants to purchase common units (the “Warrants”). We will issue 500,000 Preferred Units to the Purchasers at a price of $1,000 per Preferred Unit (the “Preferred Unit Purchase Price”), less a 1.0% structuring and origination fee, for total net proceeds, before expenses, of $495 million. In addition, we will pay a 1.0% commitment fee to the Purchasers at the closing, as well as reimburse the Purchasers for up to $400,000 of certain expenses incurred in connection with the transaction. We will also issue two tranches of Warrants to the Purchasers, which will include Warrants to purchase 5,000,000 common units with a strike price of $17.03 per unit and Warrants to purchase 10,000,000 common units with a strike price of $19.59 per unit. The Warrants may be exercised by the holders thereof at any time beginning on the one year anniversary of the closing date and before the tenth anniversary of the closing date. Upon exercise of the Warrants, we may, at our option, elect to settle the Warrants in common units on a net basis. The Series A Purchase Agreement contains customary representations, warranties and covenants of the Partnership and the Purchasers. The closing of the Private Placement is subject to customary closing conditions, including that we will have increased the aggregate commitments under our revolving credit facility to (or entered into a similar revolving facility with minimum aggregate commitments of) at least $1.3 billion.

In connection with the CDM Acquisition, on January 15, 2018, we entered into a commitment letter (the “Bridge Commitment”) with JPMorgan Chase Bank, N.A. and Barclays Bank PLC, as modified by the joinder to commitment letter and bridge fee letter entered into by the Partnership, JPMorgan Chase Bank, N.A. and Barclays Bank PLC with each of Regions Bank, Royal Bank of Canada, Wells Fargo Bank, N.A., MUFG Union Bank, N.A., a member of MUFG, a global financial group, The Bank of Nova Scotia and SunTrust Bank and certain affiliates of such parties (the “Commitment Letter”). The Commitment Letter provides for senior unsecured bridge loans in an aggregate amount up to $725 million (the “Bridge Loans”). The proceeds of such Bridge Loans may be used (a) to finance a portion of the purchase price of the CDM Acquisition and (b) to pay fees and expenses incurred in connection therewith. The availability of the borrowings is subject to the satisfaction of certain customary conditions. The Bridge Commitment will expire upon the earliest to occur of (1) the Outside Date as defined in the Contribution Agreement (as the same may be extended thereunder), (2) the consummation of the CDM Acquisition without use of the Bridge Loans, (3) the termination of the Contribution Agreement in accordance with its terms, or (4) September 30, 2018. The Bridge Loans are available to backstop a portion of the CDM Acquisition purchase price that we expect to fund with the net proceeds of other debt financing.

Our historical financial and other information in this Annual Report on Form 10-K do not give effect to any of the transactions described in this section titled “Recent Developments.”

Business Strategies

Our principal business objective is to increase the quarterly cash distributions that we pay to our unitholders over time while ensuring the ongoing stability and growth of our business. We expect to achieve this objective by executing on the following strategies:

· Capitalize on the increased need for natural gas compression in conventional and unconventional plays. We expect additional demand for compression services to result from the continuing shift of natural gas production to domestic shale plays as well as the declining production pressures of aging conventional basins. The EIA continues to expect overall natural gas production and transportation volumes, and in particular volumes from domestic shale plays, to increase over the long term. Furthermore, the changes in production volumes and pressures of shale plays over time require a wider range and increased level of compression services than in conventional basins. Our fleet of modern, flexible compression units is capable of being rapidly deployed and redeployed and is designed to operate in multiple compression stages, which will enable us to capitalize on these opportunities both in emerging shale plays and conventional basins.

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- Continue to execute on attractive organic growth opportunities. From 2007 to 2017, we grew the horsepower in our fleet of compression units and our compression revenues each at a compound annual growth rate of 15% primarily through organic growth. We believe organic growth opportunities will continue to be a source of near-term growth and we expect such organic growth levels in 2018 will be consistent with the growth seen in the second half of 2017. We seek to achieve continued organic growth by (i) increasing our business with existing customers, (ii) obtaining new customers in our existing areas of operations and (iii) expanding our operations into new geographic areas.

- Partner with customers who have significant compression needs. We actively seek to identify customers with meaningful acreage positions or significant infrastructure development in active and growing areas. We work with these customers to jointly develop long-term and adaptable solutions designed to optimize their lifecycle compression costs. We believe this is important in determining the overall economics of producing, gathering and transporting natural gas and crude oil. Our proactive and collaborative approach positions us to serve as our customers' compression service provider of choice.

- Pursue accretive acquisition opportunities. While our principal growth strategy is to continue to grow organically, we may pursue accretive acquisition opportunities, including the acquisition of complementary businesses, participation in joint ventures or the purchase of compression units from existing or new customers in conjunction with providing compression services to them. We consider opportunities that (i) are in our existing geographic areas of operations or new, high-growth regions, (ii) meet internally established economic thresholds and (iii) may be financed on reasonable terms.

- Focus on asset utilization. We seek to actively manage our business in a manner that allows us to continue to achieve high utilization rates at attractive service rates while providing us with the most financial flexibility possible. From time to time, we expect the crude oil and natural gas industry to be impacted by the cyclicality of commodity prices. During downturns in commodity prices, producers and midstream operators may reduce their capital spending, which in turn can hinder the demand for compression services. We have the ability, in response to industry conditions, to drastically and rapidly reduce our capital spending, which allows us to avoid financing organic growth with outside capital and aligns our capital spending with the demand for compression services. By reducing organic growth and avoiding new unit deliveries during downturns, we are able to conserve capital and instead focus on the deployment and re-deployment of our existing asset base. With higher utilization, we are better positioned to continue to generate attractive rates of return on our already-deployed capital.

- Maintain financial flexibility. We intend to maintain financial flexibility to be able to take advantage of growth opportunities. Historically, we have utilized our cash flow from operations, borrowings under our revolving credit facility and issuances of equity securities to fund capital expenditures to expand our compression services business. This approach has allowed us to significantly grow our fleet and the amount of cash we generate, while maintaining our debt at levels we believe are manageable for our business. We believe the appropriate management of our financial position and the resulting access to capital positions us to take advantage of future growth opportunities as they arise.

Our Operations

Compression Services

We provide compression services for a monthly service fee. As part of our services, we engineer, design, operate, service and repair our fleet of compression units and maintain related support inventory and equipment. In certain instances, we also engineer, design, install, operate, service and repair certain ancillary equipment used in conjunction with our compression services. We have consistently provided average service run times at or above the levels required by our customers. In general, our team of field service technicians services only our compression fleet and ancillary equipment. In limited circumstances for established customers, we will agree to service third-party owned equipment. We do not own any compression fabrication facilities.

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Our Compression Fleet

The fleet of compression units that we own and use to provide compression services consists of specially engineered compression units that utilize standardized components, principally engines manufactured by Caterpillar, Inc. and compressor frames and cylinders manufactured by Ariel Corporation. Our units can be rapidly and cost effectively modified for specific customer applications. Approximately 98% of our fleet horsepower as of December 31, 2017 was purchased new and the average age of our compression units was approximately five years. Our modern, standardized compression unit fleet is powered primarily by the Caterpillar 3400, 3500 and 3600 engine classes, which range from 401 to 4,735 horsepower per unit. These larger horsepower units, which we define as 400 horsepower per unit or greater, represented 83.0% of our total fleet horsepower (including compression units on order) as of December 31, 2017. In addition, a portion of our fleet consists of smaller horsepower units ranging from 30 horsepower to 399 horsepower that are primarily used in gas lift applications. We believe the young age and overall composition of our compressor fleet result in fewer mechanical failures, lower fuel usage, and reduced environmental emissions.

The following table provides a summary of our compression units by horsepower as of December 31, 2017:

Unit Horsepower	Fleet Horsepower	Number of Units	Horsepower on Order (1)	Number of Units on Order	Total Horsepower	Number of Units	Percent of Total Horsepower		Percent of Total Units	
Small horsepower <400	333,004	2,227	—	—	333,004	2,227	17.1	%	65.0	%
Large horsepower >400 and <1,000	161,822	284	—	—	161,822	284	8.3	%	8.3	%
>1,000	1,304,955	844	153,020	69	1,457,975	913	74.7	%	26.7	%
Total	1,799,781	3,355	153,020	69	1,952,801	3,424	100.0	%	100.0	%

(1) As of December 31, 2017, we had 147,500 and 5,520 horsepower on order for delivery during 2018 and 2019, respectively.

The following table sets forth certain information regarding our compression fleet as of the dates and for the periods indicated:

Operating Data:	Year Ended December 31, 2017	2016	2015	Percent Change 2017	2016
Fleet horsepower (at period end) (1)	1,799,781	1,720,547	1,712,196	4.6 %	0.5 %
Total available horsepower (at period end) (2)	1,950,301	1,730,547	1,712,196	12.7 %	1.1 %
Revenue generating horsepower (at period end) (3)	1,624,377	1,387,073	1,424,537	17.1 %	(2.6) %
Average revenue generating horsepower (4)	1,505,657	1,377,966	1,408,689	9.3 %	(2.2) %
Revenue generating compression units (at period end)	2,830	2,552	2,737	10.9 %	(6.8) %
Average horsepower per revenue generating compression unit (5)	554	534	517	3.7 %	3.3 %
Horsepower utilization (6):					
At period end	94.8 %	87.1 %	89.2 %	8.8 %	(2.4) %
Average for the period (7)	92.0 %	87.4 %	90.5 %	5.3 %	(3.4) %

(1) Fleet horsepower is horsepower for compression units that have been delivered to us (and excludes units on order). As of December 31, 2017, we had 147,500 and 5,520 horsepower on order for delivery during 2018 and 2019, respectively.

(2) Total available horsepower is revenue generating horsepower under contract for which we are billing a customer, horsepower in our fleet that is under contract but is not yet generating revenue, horsepower not yet in our fleet that is under contract but not yet generating revenue and that is subject to a purchase order and idle horsepower. Total available horsepower excludes new horsepower on order for which we do not have a compression services contract.

(3) Revenue generating horsepower is horsepower under contract for which we are billing a customer.

(4) Calculated as the average of the month-end revenue generating horsepower for each of the months in the period.

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(5) Calculated as the average of the month-end revenue generating horsepower per revenue generating compression unit for each of the months in the period.
(6) Horsepower utilization is calculated as (i) the sum of (a) revenue generating horsepower, (b) horsepower in our fleet that is under contract, but is not yet generating revenue and (c) horsepower not yet in our fleet that is under contract not yet generating revenue and that is subject to a purchase order, divided by (ii) total available horsepower less idle horsepower that is under repair. Horsepower utilization based on revenue generating horsepower and fleet horsepower at each applicable period end was 90.3%, 80.6% and 83.2% for the years ended December 31, 2017, 2016 and 2015, respectively.
(7) Calculated as the average utilization for the months in the period based on utilization at the end of each month in the period. Average horsepower utilization based on revenue generating horsepower and fleet horsepower was 85.9%, 80.3% and 85.1% for each year ended December 31, 2017, 2016, and 2015, respectively.

A growing number of our compression units contain electronic control systems that enable us to monitor the units remotely by satellite or other means to supplement our technicians' on-site monitoring visits. We intend to continue to selectively add remote monitoring systems to our fleet during 2018 where beneficial from an operating and financial standpoint. All of our compression units are designed to automatically shut down if operating conditions deviate from a pre-determined range. While we retain the care, custody, ongoing maintenance and control of our compression units, we allow our customers, subject to a defined protocol, to start, stop, accelerate and slow down compression units in response to field conditions.

We adhere to routine, preventive and scheduled maintenance cycles. Each of our compression units is subjected to rigorous sizing and diagnostic analyses, including lubricating oil analysis and engine exhaust emission analysis. We have proprietary field service automation capabilities that allow our service technicians to electronically record and track operating, technical, environmental and commercial information at the discrete unit level. These capabilities allow our field technicians to identify potential problems and often act on them before such problems result in down-time.

Generally, we expect each of our compression units to undergo a major overhaul between service deployment cycles. The timing of these major overhauls depends on multiple factors, including run time and operating conditions. A major overhaul involves the periodic rebuilding of the unit to materially extend its economic useful life or to enhance the unit's ability to fulfill broader or more diversified compression applications. Because our compression fleet is comprised of units of varying horsepower that have been placed into service with staggered initial on-line dates, we are able to schedule overhauls in a way to avoid excessive annual maintenance capital expenditures and minimize the revenue impact of down-time.

We believe that our customers, by outsourcing their compression requirements, can achieve higher compression run-times, which translates into increased volumes of either natural gas or crude oil production and, therefore, increased revenues. Utilizing our compression services also allows our customers to reduce their operating, maintenance and equipment costs by allowing us to efficiently manage their changing compression needs. In many of our service contracts, we guarantee our customers availability (as described below) ranging from 95% to 98%, depending on field- level requirements.

General Compression Service Contract Terms

The following discussion describes the material terms generally common to our compression service contracts. We generally have separate contracts for each distinct location for which we will provide compression services.

Term and termination. Our contracts typically have an initial term of between six months and five years, depending on the application and location of the compression unit. After the expiration of the applicable term, the contract continues on a month-to-month or longer basis until terminated by us or our customer upon notice as provided for in the applicable contract. As of December 31, 2017, approximately 51% of our compression services on a revenue basis were provided on a month-to-month basis to customers who continue to utilize our services following expiration of the primary term of their contracts with us.

Availability. Our contracts often provide a guarantee of specified availability. We define availability as the percentage of time in a given period that our compression services are being provided or are capable of being provided.

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Availability is reduced by instances of “down-time” that are attributable to anything other than events of force majeure or acts or failures to act by the customer. Down-time under our contracts usually begins when our services stop being provided or when we receive notice from the customer of the problem. Down-time due to scheduled maintenance is excluded from our availability commitment. Our failure to meet a stated availability guarantee may result in a service fee credit to the customer. As a consequence of our availability guarantee, we are incentivized to perform predictive and preventive maintenance on our fleet as well as promptly respond to a problem to meet our contractual commitments and ensure our customers the compression availability on which their business and our service relationship are based. For service contracts that do not have a stated availability guarantee, we work with those customers to ensure that our compression services meet their operational needs.

Fees and expenses. Our customers pay a fixed monthly fee for our services. Compression services generally are billed monthly in advance of the service period, except for certain customers whom we bill at the beginning of the service month; and payments are generally due 30 days from the date of the invoice. We are not responsible for acts of force majeure, and our customers generally are required to pay our monthly fee even during periods of limited or disrupted throughput. We are generally responsible for the costs and expenses associated with operation and maintenance of our compression equipment, although certain fees and expenses are the responsibility of our customers under the terms of their contracts. For example, all fuel gas is provided by our customers without cost to us, and in many cases customers are required to provide all water and electricity. At the customer’s option, we can provide fluids necessary to run the unit to the customer for an additional fee. We provide such fluids for a substantial majority of the compression units deployed in gas lift applications. We are also reimbursed by our customers for certain ancillary expenses such as trucking and crane operation, depending on the terms agreed to in the applicable contract, resulting in little to no gross operating margin.

Service standards and specifications. We commit to provide compression services under service contracts that typically provide that we will supply all compression equipment, tools, parts, field service support and engineering in order to meet our customers’ requirements. Our contracts do not specify the specific compression equipment we will use; instead, in consultation with the customer, we determine what equipment is necessary to perform our contractual commitments.

Title; Risk of loss. We own all of the compression equipment in our fleet that we use to provide compression services, and we normally bear the risk of loss or damage to our equipment and tools and injury or death to our personnel.

Insurance. Our contracts typically provide that both we and our customers are required to carry general liability, workers’ compensation, employers’ liability, automobile and excess liability insurance.

Marketing and Sales

Our marketing and client service functions are performed on a coordinated basis by our sales team and field technicians. Salespeople and field technicians qualify, analyze and scope new compression applications as well as regularly visit our customers to ensure customer satisfaction, to determine a customer's needs related to existing services being provided and to determine the customer's future compression service requirements. This ongoing communication allows us to quickly identify and respond to our customers' compression requirements.

Customers

Our customers consist of more than 250 companies in the energy industry, including major integrated oil companies, public and private independent exploration and production companies and midstream companies. Our ten largest customers accounted for approximately 43% of our revenue for each of the years ended December 31, 2017 and 2016.

Suppliers and Service Providers

The principal manufacturers of components for our natural gas compression equipment include Caterpillar, Inc., Cummins Inc., and Arrow Engine Company for engines, Air-X-Changers and Alfa Laval (US) for coolers, and Ariel

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Corporation, GE Oil & Gas Gemini products and Arrow Engine Company for compressor frames and cylinders. We also rely primarily on four vendors, A G Equipment Company, Alegacy Equipment, LLC, Standard Equipment Corp. and S&R Compression, LLC ("S&R"), to package and assemble our compression units. Although we rely primarily on these suppliers, we believe alternative sources for natural gas compression equipment are generally available if needed. However, relying on alternative sources may increase our costs and change the standardized nature of our fleet. We have not experienced any material supply problems to date. Although lead-times for new Caterpillar engines and new Ariel compressor frames have in the past been in excess of one year due to increased demand and supply allocations imposed on equipment packagers and end-users, currently lead-times for such engines and frames are approximately one year or shorter. Please read Part I, Item 1A ("Risk Factors—Risks Related to Our Business—We depend on a limited number of suppliers and are vulnerable to product shortages and price increases, which could have a negative impact on our results of operations").

Competition

The compression services business is highly competitive. Some of our competitors have a broader geographic scope, as well as greater financial and other resources than we do. On a regional basis, we experience competition from numerous smaller companies that may be able to more quickly adapt to changes within our industry and changes in economic conditions as a whole, more readily take advantage of available opportunities and adopt more aggressive pricing policies. Additionally, the historical availability of attractive financing terms from financial institutions and equipment manufacturers has made the purchase of individual compression units affordable to our customers. We believe that we compete effectively on the basis of price, equipment availability, customer service, flexibility in meeting customer needs, quality and reliability of our compressors and related services. Please read Part I, Item 1A ("Risk Factors—Risks Related to Our Business—We face significant competition that may cause us to lose market share and reduce our cash available for distribution").

Seasonality

Our results of operations have not historically reflected any material seasonality, and we do not currently have reason to believe seasonal fluctuations will have a material impact in the foreseeable future.

Insurance

We believe that our insurance coverage is customary for the industry and adequate for our business. As is customary in the energy services industry, we review our safety equipment and procedures and carry insurance against most, but not all, risks of our business. Losses and liabilities not covered by insurance would increase our costs. The compression business can be hazardous, involving unforeseen circumstances such as uncontrollable flows of gas or well fluids, fires and explosions or environmental damage. To address the hazards inherent in our business, we maintain insurance coverage that, subject to significant deductibles, includes physical damage coverage, third party general liability insurance, employer's liability, environmental and pollution and other coverage, although coverage for environmental and pollution related losses is subject to significant limitations. Under the terms of our standard compression services contract, we are responsible for maintaining insurance coverage on our compression equipment. Please read Part I, Item 1A ("Risk Factors—Risks Related to Our Business—We do not insure against all potential losses and could be seriously harmed by unexpected liabilities").

Environmental and Safety Regulations

We are subject to stringent and complex federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to protection of human health, safety and the environment. These regulations include compliance obligations for air emissions, water quality, wastewater discharges and solid and hazardous waste disposal, as well as regulations designed for the protection of human health and safety and threatened or endangered species. Compliance with these environmental laws and regulations may expose us to significant costs and liabilities and cause us to incur significant capital expenditures in our operations. We are often obligated to assist customers in obtaining permits or approvals in our operations from various federal, state and local authorities. Permits and approvals can be denied or delayed, which may cause us to lose potential and current customers, interrupt our

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operations and limit our growth and revenue. Moreover, failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of remedial obligations and the issuance of injunctions delaying or prohibiting operations. Private parties may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. While we believe that our operations are in substantial compliance with applicable environmental laws and regulations and that continued compliance with current requirements would not have a material adverse effect on us, there is no assurance that this trend of compliance will continue in the future. Thus, any changes in, or more stringent enforcement of, these laws and regulations that result in more stringent and costly pollution control equipment, waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on our operations and financial position.

We do not believe that compliance with federal, state or local environmental laws and regulations will have a material adverse effect on our business, financial position or results of operations or cash flows. 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 or unforeseen incidents will not cause us to incur significant costs. The following is a discussion of material environmental and safety laws that relate to our operations. We believe that we are in substantial compliance with all of these environmental laws and regulations. Please read Part I, Item 1A (“Risk Factors—Risks Related to Our Business—We are subject to substantial environmental regulation, and changes in these regulations could increase our costs or liabilities”).

Air emissions. The Clean Air Act (“CAA”) and comparable state laws regulate emissions of air pollutants from various industrial sources, including natural gas compressors, and impose certain monitoring and reporting requirements. Such emissions are regulated by air emissions permits, which are applied for and obtained through the various state or federal regulatory agencies. Our standard natural gas compression contract provides that the customer is responsible for obtaining air emissions permits and assuming the environmental risks related to site operations. In some instances, our customers may be required to aggregate emissions from a number of different sources on the theory that the different sources should be considered a single source. Any such determinations could have the effect of making projects more costly than our customers expected and could require the installation of more costly emission controls, which may lead some of our customers not to pursue certain projects.

Increased obligations of operators to reduce air emissions of nitrogen oxides and other pollutants from internal combustion engines in transmission service have been enacted by governmental authorities. For example, in 2010, the U.S. Environmental Protection Agency (“EPA”) published new regulations under the CAA to control emissions of hazardous air pollutants from existing stationary reciprocal internal combustion engines, also known as Quad Z regulations. The rule requires us to undertake certain expenditures and activities, including purchasing and installing emissions control equipment on certain compressor engines and generators.

In recent years, the EPA has lowered the National Ambient Air Quality Standard (“NAAQs”) for several air pollutants. For example, in 2015, the EPA finalized a rule strengthening the primary and secondary standards for ground level ozone, both of which are 9-hour concentration standards of 70 parts per billion (“ppb”). After the EPA revises a NAAQS standard, the states are expected to establish revised attainment/non-attainment regions. State implementation of the revised NAAQS could result in stricter permitting requirements, delay or prohibit our customers' ability to obtain such permits, and result in increased expenditures for pollution control equipment, which could impact our customers' operations, increase the cost of additions to property, plant, and equipment, and negatively impact our business.

In 2012, the EPA finalized rules that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA's rule package included New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds ("VOCs") and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The rules established specific new requirements regarding emissions from compressors and controllers at natural gas processing plants, dehydrators, storage tanks and other production equipment as well as the first federal air standards for natural gas wells that are hydraulically fractured. In June 2016, the EPA took steps to expand on these regulations when it published New Source Performance Standards, known as Subpart OOOOa, that require certain new, modified or reconstructed facilities in the oil and natural gas sector to reduce these methane gas and VOC emissions. These Subpart

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OOOOa standards will expand the 2012 New Source Performance Standards by using certain equipment-specific emissions control practices, requiring additional controls for pneumatic controllers and pumps as well as compressors, and imposing leak detection and repair requirements for natural gas compressor and booster stations. However, the EPA announced in April 2017 that it intends to reconsider certain aspects of the 2016 New Source Performance Standards, and in May 2017, the EPA issued an administrative stay of key provisions of the rule, but was promptly ordered by the D.C. Circuit to implement the rule. The EPA also proposed 60-day and two-year stays of certain provisions in June 2017 and published a Notice of Data Availability in November 2017 seeking comment and providing clarification regarding the agency’s legal authority to stay the rule.

Subpart OOOOa and any additional regulation of air emissions from the oil and gas sector could result in increased expenditures for pollution control equipment, which could impact our customers’ operations and negatively impact our business.

We are also subject to air regulation at the state level. For example, the Texas Commission on Environmental Quality (“TCEQ”) has finalized revisions to certain air permit programs that significantly increase the air permitting requirements for new and certain existing oil and gas production and gathering sites for 15 counties in the Barnett Shale production area. The final rule establishes new emissions standards for engines, which could impact the operation of specific categories of engines by requiring the use of alternative engines, compressor packages or the installation of aftermarket emissions control equipment. The rule became effective for the Barnett Shale production area in April 2011, with the lower emissions standards becoming applicable between 2015 and 2030 depending on the type of engine and the permitting requirements. The cost to comply with the revised air permit programs is not expected to be material at this time. However, the TCEQ has stated it will consider expanding application of the new air permit program statewide. At this point, we cannot predict the cost to comply with such requirements if the geographic scope is expanded.

There can be no assurance that future requirements compelling the installation of more sophisticated emission control equipment would not have a material adverse impact on our business, financial condition, results of operations and cash available for distribution.

Climate change. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of natural gas, are examples of greenhouse gases. In recent years, the U.S. Congress has considered legislation to reduce emissions of greenhouse gases. It presently appears unlikely that comprehensive climate legislation will be passed by either house of Congress in the near future, although energy legislation and other initiatives are expected to be proposed that may be relevant to greenhouse gas emissions issues. However, almost half of the states have begun to address greenhouse gas emissions, primarily through the planned development of emission inventories or regional greenhouse gas cap and trade programs. Depending on the particular program, we could be required to control greenhouse gas emissions or to purchase and surrender allowances for greenhouse gas emissions resulting from our operations.

Independent of Congress, the EPA undertook to adopt regulations controlling greenhouse gas emissions under its existing CAA authority. For example, in 2009, the EPA officially published its findings that emissions of carbon dioxide, methane and other greenhouse gases endanger human health and the environment, allowing the agency to proceed with the adoption of regulations that restrict emissions of greenhouse gases under existing provisions of the CAA. In 2009 and 2010, the EPA adopted rules regarding regulation of greenhouse gas emissions from motor vehicles and requiring the reporting of greenhouse gas emissions in the U.S. from specified large greenhouse gas emission sources, including petroleum and natural gas facilities such as natural gas transmission compression facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year.

In 2015, the EPA published standards of performance for greenhouse gas emissions from new power plants. The final rule establishes a performance standard for integrated gasification combined cycled units and utility boilers based on the use of the best system of emission reduction that EPA has determined has been adequately demonstrated for each type of unit. The rule also sets limits for stationary natural gas combustion turbines based on the use of natural gas combined cycle technology.

The EPA also promulgated the Clean Power Plan rule (“CCP”), which is intended to reduce carbon emissions from existing power plants by 32 percent from 2005 levels by 2030. In February 2016, the U.S. Supreme Court granted a stay

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of the implementation of the CPP, which will remain in effect throughout the pendency of the appeals process including at the U.S. Court of Appeals of the D.C. Circuit and the Supreme Court through any certiorari petition that may be granted. It is not yet clear how the courts will rule on the legality of the CPP. Additionally, in October 2017 the EPA proposed to repeal the CPP, although the final outcome of this action and the pending litigation regarding the CPP is uncertain at this time. In connection with the proposed repeal, EPA issued an Advance Notice of Proposed Rulemaking ("ANPRM") in December 2017 regarding emission guidelines to limit emissions of greenhouse gases ("GHGs") from existing electricity utility generating units. The ANPRM seeks comment regarding what the EPA should include in a potential new, existing-source regulation under the Clean Air Act of GHG emissions from electric utility generating units that it may propose. If the effort to repeal the rules is unsuccessful and the rules are upheld at the conclusion of this appellate process and were implemented in their current form, or if the ANPRM results in a different proposal to control GHG emissions from electric utility generating units, demand for the oil and natural gas our customers produce may decrease. In addition, the costs of electricity for our operations may also increase, thereby adversely impacting our business.

In addition to the EPA, the Bureau of Land Management ("BLM") has also promulgated rules to regulate hydraulic fracturing. In 2015, the BLM promulgated new requirements relating to well construction, water management, and chemical disclosure for companies drilling on federal and tribal land. The agency subsequently finalized a rule in December 2017 rescinding the 2015 rule. On November 15, 2016, the BLM also finalized a rule to reduce the flaring, venting and leaking of methane from oil and gas operations on federal and Indian lands ("BLM Venting Rule"). The rule requires operators to use certain technologies and equipment to reduce flaring and to periodically inspect their operations for leaks. The rule also specifies when operators owe the government royalties for flared gas. In November 2016, state and industry groups challenged this BLM rule in the U.S. District Court for the District of Wyoming, asserting that the BLM lacks authority to prescribe air quality regulations. The court stayed the case in December 2017, however, when the BLM finalized a decision to delay implementation of key requirements in the rule for one year. If the BLM Venting Rule is not repealed and survives legal challenge, it could increase the costs of operations for our clients who operate on BLM land, and negatively impact our business.

At the international level, nearly 200 nations entered into an international climate agreement at the 2015 United Nations Framework Convention on Climate Change in Paris, under which participating countries did not assume any binding obligation to reduce future emissions of GHGs but instead pledged to voluntarily limit or reduce future emissions. Although the U.S. became a party to the Paris Agreement in April 2016, the Trump administration announced in June 2017 its intention to either withdraw from the Paris Agreement or renegotiate more favorable terms. However, the Paris Agreement stipulates that participating countries must wait four years before withdrawing from the agreement. Despite the planned withdrawal, certain U.S. city and state governments have announced their intention to satisfy their proportionate obligations under the Paris Agreement.

Although it is not currently possible to predict with specificity how any proposed or future greenhouse gas legislation, regulation, agreements or initiatives will impact our business, any legislation or regulation of greenhouse gas emissions that may be imposed in areas in which we conduct business could result in increased compliance costs or additional operating restrictions or reduced demand for our services, and could have a material adverse effect on our business, financial condition and results of operations.

Finally, it should be noted that some scientists have concluded that increasing concentrations of GHG 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 of those effects were to occur, they could have an adverse effect on our assets and operations.

Water discharge. The Clean Water Act ("CWA") and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the U.S. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. The CWA and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including jurisdictional wetlands, unless authorized by an appropriately issued permit. The CWA also requires the development and implementation of spill prevention, control and countermeasures, including the construction and maintenance of containment berms and similar structures, if required, to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak at

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such facilities. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. Federal and state regulatory agencies can impose administrative, civil and criminal penalties as well as other enforcement mechanisms for non-compliance with discharge permits or other requirements of the CWA and analogous state laws and regulations.

Our compression operations do not generate process wastewaters that are discharged to waters of the U.S. In any event, our customers assume responsibility under the majority of our standard natural gas compression contracts for obtaining any permits that may be required under the CWA whether for discharges or developing the property by filling wetlands. Considerable legal uncertainty exists surrounding the standard for what constitutes jurisdictional waters and wetlands subject to the protections and requirements of the CWA. A 2015 rulemaking by the EPA to revise the standard was stayed nationwide by the U.S. Court of Appeals for the Sixth Circuit and stayed for certain primarily western states by a U.S. District Court in North Dakota. For now, the EPA and the Army Corps of Engineers (“Corps”) will continue to apply the existing standard for what constitutes a water of the U.S. as determined by the Supreme Court in the Rapanos case and post-Rapanos guidance. Should the 2015 rule take effect, or should a different rule expanding the definition of what constitutes a water of the U.S. be promulgated as a result of the EPA and the Corps’ rulemaking process, our customers could face increased costs and delays due to additional permitting and regulatory requirements and possible challenges to permitting decisions.

Safe Drinking Water Act. A significant portion of our customers’ natural gas production is developed from unconventional sources that require hydraulic fracturing as part of the completion process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into the formation to stimulate gas production. Legislation to amend the Safe Drinking Water Act (“SDWA”) to repeal the exemption for hydraulic fracturing from the definition of “underground injection” and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, have been proposed and the U.S. Congress continues to consider legislation to amend the SDWA. Scrutiny of hydraulic fracturing activities continues in other ways, with the EPA having commenced a multi-year study of 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 concluded that “water cycle” activities associated with hydraulic fracturing may impact drinking water resources “under some circumstances,” noting that the following hydraulic fracturing water cycle activities and local- or regional-scale factors are more likely than others to result in more frequent or more severe impacts: water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits. The EPA also has announced that it believes hydraulic fracturing using fluids containing diesel fuel can be regulated under the SDWA notwithstanding the SDWA’s general exemption for hydraulic fracturing. Several states have also proposed or adopted legislative or regulatory restrictions on hydraulic fracturing, including prohibitions on the practice. We cannot predict the future of such legislation and what additional, if any, provisions would be included. If additional levels of regulation, restrictions and permits were required through the adoption of new laws and regulations at the federal or state level or the development of new interpretations of those requirements by the agencies that issue the permits, that could lead to delays, increased operating costs and process prohibitions that could reduce demand for our compression services, which would materially adversely affect our revenue and results of operations.

Solid waste. The Resource Conservation and Recovery Act ("RCRA") and comparable state laws control the management and disposal of hazardous and non-hazardous waste. These laws and regulations govern the generation, storage, treatment, transfer and disposal of wastes that we generate including, but not limited to, used oil, antifreeze, filters, sludges, paint, solvents and sandblast materials. The EPA and various state agencies have limited the approved methods of disposal for these types of wastes.

Site remediation. The Comprehensive Environmental Response Compensation and Liability Act ("CERCLA") and comparable state laws impose strict, joint and several liability without regard to fault or the legality of the original conduct on certain classes of persons that contributed to the release of a hazardous substance into the environment. These persons include the owner and operator of a disposal site where a hazardous substance release occurred and any company that transported, disposed of or arranged for the transport or disposal of hazardous substances released at the site. Under CERCLA, such persons may be liable for the costs of remediating the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. In addition, where contamination may be present, it is not uncommon for the neighboring landowners and other third parties to file claims for personal injury, property damage and recovery of response costs. While we generate materials in the course of our operations that may be regulated as hazardous substances, we have not received notification that we may be potentially responsible for cleanup costs under CERCLA at any site.

While we do not currently own or lease any material facilities or properties for storage or maintenance of our inactive compression units, we may use third party properties for such storage and possible maintenance and repair activities. In addition, our active compression units typically are installed on properties owned or leased by third party customers and operated by us pursuant to terms set forth in the natural gas compression services contracts executed by those customers. Under most of our natural gas compression services contracts, our customers must contractually indemnify us for certain damages we may suffer as a result of the release into the environment of hazardous and toxic substances. We are not currently responsible for any remedial activities at any properties we use; however, there is always the possibility that our future use of those properties may result in spills or releases of petroleum hydrocarbons, wastes or other regulated substances into the environment that may cause us to become subject to remediation costs and liabilities under CERCLA, RCRA or other environmental laws. We cannot provide any assurance that the costs and liabilities associated with the future imposition of such remedial obligations upon us would not have a material adverse effect on our operations or financial position.

Safety and health. The Occupational Safety and Health Act (“OSHA”) and comparable state laws strictly govern the protection of the health and safety of employees. The OSHA hazard communication standard, the EPA community right-to-know regulations under the Title III of CERCLA and similar state statutes require that we organize and, as necessary, disclose information about hazardous materials used or produced in our operations to various federal, state and local agencies, as well as employees.

Employees

USAC Management, a wholly owned subsidiary of our general partner, performs certain management and other administrative services for us, such as accounting, corporate development, finance and legal. All of our employees, including our executive officers, are employees of USAC Management. As of December 31, 2017, USAC Management had 426 full time employees. None of our employees are subject to collective bargaining agreements. We consider our employee relations to be good.

Available Information

Our website address is usacompression.com. We make available, free of charge at the "Investor Relations" portion of our website, our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), as soon as reasonably practicable after such reports are electronically filed with, or furnished to, the Securities and Exchange Commission ("SEC"). The information contained on our website does not constitute part of this report.

The SEC maintains a website that contains these reports at sec.gov. Any materials we file with the SEC also may be read or copied at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. Information concerning the operation of the Public Reference Room may be obtained by calling the SEC at (800) 732-0330.

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ITEM 1A.Risk Factors

As described in Part I (“Disclosure Regarding Forward-Looking Statements”), this report contains forward-looking statements regarding us, our business and our industry. The risk factors described below, among others, could cause our actual results to differ materially from the expectations reflected in the forward-looking statements. If any of the following risks were to occur, our business, financial condition or results of operations could be materially and adversely affected. In that case, we might not be able to continue to pay our current quarterly distribution on our common units or grow such distributions and the trading price of our common units could decline.

Risks Related to Our Business

We may not have 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 make cash distributions at our current distribution rate to our unitholders.

In order to make cash distributions at our current distribution rate of $0.525 per unit per quarter, or $2.10 per unit per year, we will require available cash of $33.1 million per quarter, or $132.2 million per year, based on the number of common units and the 1.2% general partner interest outstanding as of February 8, 2018. Under our cash distribution policy, the amount of cash we can distribute to our unitholders 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 level of production of, demand for, and price of natural gas and crude oil, particularly the level of production in the locations where we provide compression services;
- the fees we charge, and the margins we realize, from our compression services;
- the cost of achieving organic growth in current and new markets;
- the ability to effectively integrate any assets or businesses we acquire, including the CDM Acquisition;
- the level of competition from other companies; and
- prevailing global and regional economic and regulatory conditions, and their impact on us and our customers.

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

- the levels of our maintenance capital expenditures and expansion capital expenditures;
- the level of our operating costs and expenses;
- our debt service requirements and other liabilities;
- fluctuations in our working capital needs;
- restrictions contained in our revolving credit facility;
- the cost of acquisitions;
- fluctuations in interest rates;
- the financial condition of our customers;
- our ability to borrow funds and access the capital markets; and

· the amount of cash reserves established by our general partner.

A long-term reduction in the demand for, or production of, natural gas or crude oil could adversely affect the demand for our services or the prices we charge for our services, which could result in a decrease in our revenues and cash available for distribution to unitholders.

The demand for our compression services depends upon the continued demand for, and production of, natural gas and crude oil. Demand may be affected by, among other factors, natural gas prices, crude oil prices, weather, availability of alternative energy sources, governmental regulation and general demand for energy. Any prolonged, substantial reduction in the demand for natural gas or crude oil would likely depress the level of production activity and result in a decline in the demand for our compression services, which could result in a reduction in our revenues and our cash available for distribution.

In particular, lower natural gas or crude oil prices over the long term could result in a decline in the production of natural gas or crude oil, respectively, resulting in reduced demand for our compression services. For example, the North American rig count, as measured by Baker Hughes, hit a 2014 peak of 1,931 rigs on September 12, 2014, and at that time, Henry Hub natural gas spot prices were $3.82 per MMBtu and West Texas Intermediate ("WTI") crude oil spot prices were $92.18 per barrel. By contrast, the North American rig count hit a modern low of 404 rigs on May 20, 2016, and at that time, Henry Hub natural gas spot prices were $1.92 per MMBtu and WTI crude oil spot prices were $47.67 per barrel. This slowdown in new drilling activity caused some pressure on service rates for new and existing services and contributed to a decline in our utilization during 2015 and into 2016. By the end of December 2017, the North American rig count was 929 rigs, as WTI crude oil spot prices hovered near their highest level since the summer of 2015 at $60.46 per barrel and Henry Hub natural gas spot prices were $2.81 per MMBtu. Although commodity prices and our utilization increased during 2016 and 2017, the increased activity resulting from such increased commodity prices may not continue or the trend of increasing commodity prices may reverse. In addition, a small portion of our fleet is used in connection with crude oil production using horizontal drilling techniques. During the period of low crude oil prices, we experienced pressure on service rates from our customers in gas lift applications; if commodity prices decline from current levels, we may experience pressure on service rates.

Additionally, an increasing percentage of natural gas and crude oil production comes from unconventional sources, such as shales, tight sands and coalbeds. Such sources can be less economically feasible to produce in low commodity price environments, in part due to costs related to compression requirements, and a reduction in demand for natural gas or gas lift for crude oil may cause such sources of natural gas or crude oil to be uneconomic to drill and produce, which could in turn negatively impact the demand for our services. Further, if demand for our services decreases, we may be asked to renegotiate our service contracts at lower rates. In addition, governmental regulation and tax policy may impact the demand for natural gas or crude oil or impact the economic feasibility of development of new fields or production of existing fields, which are important components of our ability to expand.

We have several key customers. The loss of any of these customers would result in a decrease in our revenues and cash available for distribution.

We provide compression services under contracts with several key customers. The loss of one of these key customers may have a greater effect on our financial results than for a company with a more diverse customer base. Our ten largest customers accounted for approximately 43% of our revenue for each of the years ended December 31, 2017 and 2016. The loss of all or even a portion of the compression services we provide to our key customers, as a result of competition or otherwise, could have a material adverse effect on our business, results of operations, financial condition and cash available for distribution.

The deterioration of the financial condition of our customers could adversely affect our business.

During times when the natural gas or crude oil markets weaken, our customers are more likely to experience financial difficulties, including being unable to access debt or equity financing, which could result in a reduction in our customers' spending for our services. For example, our customers could seek to preserve capital by using lower cost

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providers, not renewing month-to-month contracts or determining not to enter into any new compression service contracts. A significant decline in commodity prices may cause certain of our customers to reconsider near-term capital budgets, which may impact large-scale natural gas infrastructure and crude oil production activities. Reduced demand for our services could adversely affect our business, results of operations, financial condition and cash flows. In addition, in the course of our business we hold accounts receivable from our customers. In the event that any such customer was to enter into bankruptcy, we could lose all or a portion of such outstanding accounts receivable associated with that customer. Further, if a customer was to enter into bankruptcy, it could also result in the cancellation of all or a portion of our service contracts with such customer at significant expense to us.

We face significant competition that may cause us to lose market share and reduce our cash available for distribution.

The compression business is highly competitive. Some of our competitors have a broader geographic scope, as well as greater financial and other resources than we do. Our ability to renew or replace existing contracts with our customers at rates sufficient to maintain current revenue and cash flows could be adversely affected by the activities of our competitors and our customers. If our competitors substantially increase the resources they devote to the development and marketing of competitive services or substantially decrease the prices at which they offer their services, we may be unable to compete effectively. Some of these competitors may expand or construct newer, more powerful or more flexible compression fleets that would create additional competition for us. All of these competitive pressures could have a material adverse effect on our business, results of operations, financial condition and reduce our cash available for distribution.

Our customers may choose to vertically integrate their operations by purchasing and operating their own compression fleet, expanding the amount of compression units they currently own or using alternative technologies for enhancing crude oil production.

Our customers that are significant producers, processors, gatherers and transporters of natural gas and crude oil may choose to vertically integrate their operations by purchasing and operating their own compression fleets in lieu of using our compression services. The historical availability of attractive financing terms from financial institutions and equipment manufacturers facilitates this possibility by making the purchase of individual compression units increasingly affordable to our customers. In addition, there are many technologies available for the artificial enhancement of crude oil production, and our customers may elect to use these alternative technologies instead of the gas lift compression services we provide. Such vertical integration, increases in vertical integration or use of alternative technologies could result in decreased demand for our compression services, which may have a material adverse effect on our business, results of operations, financial condition and reduce our cash available for distribution.

A significant portion of our services are provided to customers on a month-to-month basis, and we cannot be sure that such customers will continue to utilize our services.

Our contracts typically have an initial term of between six months and five years, depending on the application and location of the compression unit. After the expiration of the applicable term, the contract continues on a month-to-month or longer basis until terminated by us or our customers upon notice as provided for in the applicable contract. As of December 31, 2017, approximately 51% of our compression services on a revenue basis were provided on a month-to-month basis to customers who continue to utilize our services following expiration of the primary term of their contracts with us. These customers can generally terminate their month-to-month compression services contracts on 30-days' written notice. If a significant number of these customers were to terminate their month-to-month services, or attempt to renegotiate their month-to-month contracts at substantially lower rates, it could have a material adverse effect on our business, results of operations, financial condition and cash available for distribution.

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We may be unable to grow our cash flows if we are unable to expand our business, which could limit our ability to maintain or increase distributions to our unitholders.

A principal focus of our strategy is to continue to grow the per unit distribution on our units by expanding our business over time. Our future growth will depend upon a number of factors, some of which we cannot control. These factors include our ability to:

- develop new business and enter into service contracts with new customers;
- retain our existing customers and maintain or expand the services we provide them;
- maintain or increase the fees we charge, and the margins we realize, from our compression services;
- recruit and train qualified personnel and retain valued employees;
- expand our geographic presence;
- effectively manage our costs and expenses, including costs and expenses related to growth;
- consummate accretive acquisitions;
- obtain required debt or equity financing on favorable terms for our existing and new operations; and
- meet customer specific contract requirements or pre-qualifications.

If we do not achieve our expected growth, we may not be able to maintain or increase distributions to our unitholders, in which event the market price of our units will likely decline materially.

We may be unable to grow successfully through acquisitions, and we may not be able to integrate effectively the businesses we may acquire, which may impact our operations and limit our ability to increase distributions to our unitholders.

From time to time, we may choose to make business acquisitions, such as the CDM Acquisition, to pursue market opportunities, increase our existing capabilities and expand into new areas of operations. While we have reviewed acquisition opportunities in the past and will continue to do so in the future, we may not be able to identify attractive acquisition opportunities or successfully acquire identified targets. In addition, we may not be successful in integrating any future acquisitions, including the CDM Acquisition, into our existing operations, which may result in unforeseen operational difficulties or diminished financial performance or require a disproportionate amount of our management's attention. Even if we are successful in integrating future acquisitions into our existing operations, we may not derive the benefits, such as operational or administrative synergies, that we expected from such acquisitions, which may result in the commitment of our capital resources without the expected returns on such capital. Furthermore, competition for acquisition opportunities may escalate, increasing our cost of making acquisitions or causing us to refrain from making acquisitions. Our inability to make acquisitions, or to integrate acquisitions successfully into our existing operations, may adversely impact our operations and limit our ability to increase distributions to our unitholders.

Our ability to grow in the future is dependent on our ability to access external expansion capital.

Our partnership agreement requires us to distribute to our unitholders all of our available cash, which excludes prudent operating reserves. We expect that we will rely primarily upon cash generated by operating activities and, where necessary, borrowings under our revolving credit facility and the issuance of debt and equity securities, to fund expansion capital expenditures. However, we may not be able to obtain equity or debt financing on terms favorable to us, or at all. To the extent we are unable to efficiently finance growth externally, our ability to increase distributions to our unitholders could be significantly impaired. In addition, because we distribute all of our available cash, which excludes prudent operating reserves, we may not grow as quickly as businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units including the Preferred Units described in Item 1 ("Business—Recent Developments"), 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, subject to certain

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restrictions in our partnership agreement that will take effect when the Preferred Units are issued. Similarly, the incurrence of borrowings or other debt by us to finance our growth strategy would result in interest expense, which in turn would affect our cash available for distribution.

Our debt levels may limit our flexibility in obtaining additional financing, pursuing other business opportunities and paying distributions.

We have a $1.1 billion revolving credit facility that matures in January 2020. In addition, we have the option to increase the amount of total commitments under the revolving credit facility by $200 million, subject to receipt of lender commitments and satisfaction of other conditions. As of December 31, 2017, we had outstanding borrowings of $782.9 million with a leverage ratio of 4.65x, borrowing base availability (based on our borrowing base) of $272.1 million and, subject to compliance with the applicable financial covenants, available borrowing capacity under the revolving credit facility of $101.6 million. Financial covenants permit a maximum leverage ratio of (A) 5.25 to 1.0 as of the end of the fiscal quarter ending December 31, 2017 and (B) 5.00 to 1.0 thereafter. As of February 8, 2018, we had outstanding borrowings of $815.0 million.

Our ability to incur additional debt is subject to limitations in our revolving credit facility, including certain financial covenants. Our 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, acquisitions or other purposes may not be available or such financing may not be available on favorable terms;

- we will need a portion of our cash flow to make payments on our indebtedness, reducing the funds that would otherwise be available for operating activities, future business opportunities and distributions; and

- our debt level will make us more vulnerable, than our competitors with less debt, to competitive pressures or a downturn in our business or the economy generally.

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. In addition, our ability to service our debt under the revolving credit facility could be impacted by market interest rates, as all of our outstanding borrowings are subject to interest rates that fluctuate with movements in interest rate markets. A substantial increase in the interest rates applicable to our outstanding borrowings could have a material impact on our cash available for distribution. If our operating results are not sufficient to service our current or future indebtedness, we could be forced to take actions such as reducing distributions, reducing or delaying our business activities, acquisitions, investments or capital expenditures, selling assets, restructuring or refinancing our debt or seeking additional equity capital. We may be unable to effect any of these actions on terms satisfactory to us, or at all.

Restrictions in our revolving credit facility may limit our ability to make distributions to our unitholders and may limit our ability to capitalize on acquisition and other business opportunities.

The operating and financial restrictions and covenants in our revolving credit facility and any future financing agreements could restrict our ability to finance future operations or capital needs or to expand or pursue our business activities. Our revolving credit facility restricts or limits our ability (subject to exceptions) to:

- grant liens;
- make certain loans or investments;
- incur additional indebtedness or guarantee other indebtedness;
- enter into transactions with affiliates;

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- merge or consolidate;
- sell our assets; or
- make certain acquisitions.

Furthermore, our revolving credit facility contains certain operating and financial covenants. Our ability to comply with these covenants and restrictions may be affected by events beyond our control, including prevailing economic, financial and industry conditions. If market or other economic conditions deteriorate, our ability to comply with these covenants may be impaired. If we violate any of the restrictions, covenants, ratios or other tests in our revolving credit facility, a significant portion of our indebtedness may become immediately due and payable, our lenders' commitment to make further loans to us may terminate, and we may be prohibited from making distributions to our unitholders. We might not have, or be able to obtain, sufficient funds to make these accelerated payments. We may not be able to replace such revolving credit facility, or if we are, any subsequent replacement of our revolving credit facility or any new indebtedness could have similar or greater restrictions. Please read Part II, Item 7 ("Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Description of Revolving Credit Facility").

Restrictions in our partnership agreement related to the Preferred Units may limit our ability to make distributions to our unitholders and may limit our ability to capitalize on acquisition and other business opportunities.

The operating and financial restrictions and covenants in our partnership agreement related to the Preferred Units could restrict our ability to finance future operations or capital needs or to expand or pursue our business activities. If the Preferred Units are issued, our partnership agreement will restrict or limit our ability (subject to exceptions) to:

- pay distributions on any junior securities, including the common units, prior to paying the quarterly distribution payable to the holders of the Preferred Units, including any previously accrued and unpaid distributions;
- issue any securities that rank senior to or pari passu with the Preferred Units; however, we will be able to issue an unlimited number of securities ranking junior to the Preferred Units, including junior preferred units and common units; and
- incur Indebtedness (as defined in our revolving credit facility) if, after giving pro forma effect to such incurrence, the Leverage Ratio (as defined in our revolving credit facility) determined as of the last day of the most recently ended fiscal quarter would exceed 6.5x, subject to certain exceptions.

An impairment of goodwill or other intangible assets could reduce our earnings.

We have recorded $35.9 million of goodwill and $71.7 million of other intangible assets as of December 31, 2017. Goodwill is recorded when the purchase price of a business exceeds the fair market value of the tangible and separately measurable intangible net assets. Generally accepted accounting principles of the United States ("GAAP") requires us to test goodwill for impairment on an annual basis or when events or circumstances occur indicating that goodwill might be impaired. Any event that causes a reduction in demand for our services could result in a reduction of our estimates of future cash flows and growth rates in our business. These events could cause us to record impairments of goodwill or other intangible assets. If we determine that any of our goodwill or other intangible assets are impaired, we will be required to take an immediate charge to earnings with a corresponding reduction of partners' capital resulting in an increase in balance sheet leverage as measured by debt to total capitalization. There was no impairment recorded for goodwill or other intangible assets for the years ended December 31, 2017 and 2016. For the year ended December 31, 2015, we recognized a $172.2 million impairment of goodwill due primarily to the decline in our unit price, the sustained decline in global commodity prices, expected reduction in the capital budgets of certain of our customers and the impact these factors have on our expected future cash flows (see Note 2 of our consolidated financial statements). There was no impairment recorded for other intangible assets for the year ended December 31, 2015.

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Impairment in the carrying value of long-lived assets could reduce our earnings.

We have a significant amount of long-lived assets on our consolidated balance sheet. Under GAAP, long-lived assets are required to be reviewed for impairment when events or circumstances indicate that its carrying value may not be recoverable or will no longer be utilized in the operating fleet. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If business conditions or other factors cause the expected undiscounted cash flows to decline, we may be required to record non-cash impairment charges. Events and conditions that could result in impairment in the value of our long-lived assets include changes in the industry in which we operate, competition, advances in technology, adverse changes in the regulatory environment, or other factors leading to reduction in expected long-term profitability. For example, during the fiscal years ended December 31, 2017 and 2016, we evaluated the future deployment of our idle fleet under then-current market conditions and determined to retire and either sell or re-utilize the key components of 40 and 29 compressor units, or approximately 11,000 and 15,000 horsepower, that were previously used to provide services in our business. As a result, we recognized impairments of $5.0 million and $5.8 million during the years ended December 31, 2017 and 2016, respectively.

Our ability to manage and grow our business effectively may be adversely affected if we lose management or operational personnel.

We depend on the continuing efforts of our executive officers. The departure of any of our executive officers could have a significant negative effect on our business, operating results, financial condition and on our ability to compete effectively in the marketplace.

Additionally, our ability to hire, train and retain qualified personnel will continue to be important and could become more challenging as we grow and to the extent energy industry market conditions are competitive. When general industry conditions are good, the competition for experienced operational and field technicians increases as other energy and manufacturing companies’ needs for the same personnel increases. Our ability to grow or even to continue our current level of service to our current customers could be adversely impacted if we are unable to successfully hire, train and retain these important personnel.

We depend on a limited number of suppliers and are vulnerable to product shortages and price increases, which could have a negative impact on our results of operations.

The substantial majority of the components for our natural gas compression equipment are supplied by Caterpillar Inc., Cummins Inc. and Arrow Engine Company for engines, Air-X-Changers and Alfa Laval (US) for coolers, and Ariel Corporation, GE Oil & Gas Gemini products and Arrow Engine Company for compressor frames and cylinders. Our reliance on these suppliers involves several risks, including price increases and a potential inability to obtain an adequate supply of required components in a timely manner. We also rely primarily on four vendors, A G Equipment Company, Alegacy Equipment, LLC, Standard Equipment Corp. and S&R, to package and assemble our compression units. We do not have long-term contracts with these suppliers or packagers, and a partial or complete loss of any of these sources could have a negative impact on our results of operations and could damage our customer relationships. Some of these suppliers manufacture the components we purchase in a single facility and any damage to that facility could lead to significant delays in delivery of completed units.

We are subject to substantial environmental regulation, and changes in these regulations could increase our costs or liabilities.

We are subject to stringent and complex federal, state and local laws and regulations, including laws and regulations regarding the discharge of materials into the environment, emission controls and other environmental protection and occupational health and safety concerns, as discussed in detail in Item 1 (“Business Environmental and Safety Regulations”). Environmental laws and regulations may, in certain circumstances, impose strict liability for environmental contamination, which may render us liable for remediation costs, natural resource damages and other damages as a result of our conduct that was lawful at the time it occurred or the conduct of, or conditions caused by, prior owners or operators or other third parties. In addition, where contamination may be present, it is not uncommon for neighboring land owners and other third parties to file claims for personal injury, property damage and recovery of

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response costs. Remediation costs and other damages arising as a result of environmental laws and regulations, and costs associated with new information, changes in existing environmental laws and regulations or the adoption of new environmental laws and regulations could be substantial and could negatively impact our financial condition or results of operations. Moreover, failure to comply with these environmental laws and regulations may result in the imposition of administrative, civil and criminal penalties and the issuance of injunctions delaying or prohibiting operations.

We conduct operations in a wide variety of locations across the continental U.S. These operations require U.S. federal, state or local environmental permits or other authorizations. Our operations may require new or amended facility permits or licenses from time to time with respect to storm water discharges, waste handling or air emissions relating to equipment operations, which subject us to new or revised permitting conditions that may be onerous or costly to comply with. Additionally, the operation of compression units may require individual air permits or general authorizations to operate under various air regulatory programs established by rule or regulation. These permits and authorizations frequently contain numerous compliance requirements, including monitoring and reporting obligations and operational restrictions, such as emission limits. Given the wide variety of locations in which we operate, and the numerous environmental permits and other authorizations that are applicable to our operations, we may occasionally identify or be notified of technical violations of certain requirements existing in various permits or other authorizations. We could be subject to penalties for any noncompliance in the future.

In our business, we routinely deal with natural gas, oil and other petroleum products at our worksites. Hydrocarbons or other hazardous substances or wastes may have been disposed or released on, under or from properties used by us to provide compression services or inactive compression unit storage or on or under other locations where such substances or wastes have been taken for disposal. These properties may be subject to investigatory, remediation and monitoring requirements under federal, state and local environmental laws and regulations.

The modification or interpretation of existing environmental laws or regulations, the more vigorous enforcement of existing environmental laws or regulations, or the adoption of new environmental laws or regulations may also negatively impact oil and natural gas exploration and production, gathering and pipeline companies, including our customers, which in turn could have a negative impact on us.

New regulations, proposed regulations and proposed modifications to existing regulations under the Clean Air Act, if implemented, could result in increased compliance costs.

New regulations or proposed modifications to existing regulations under the Clean Air Act, as discussed in detail in Item 1 (“Business Environmental and Safety Regulations”), may lead to adverse impacts on our business, financial condition, results of operations, and cash available for distribution. For example, in 2015, the EPA finalized a rule strengthening the primary and secondary National Ambient Air Quality Standards (“NAAQS”) for ground level ozone, both of which are 8-hour concentration standards of 70 parts per billion (“ppb”). After the EPA revises a NAAQS standard, the states are expected to establish revised attainment/non-attainment regions. State implementation of the revised NAAQS could result in stricter permitting requirements, delay or prohibit our customers’ ability to obtain such permits, and result in increased expenditures for pollution control equipment, which could impact our customers' operations, increase the cost of additions to property, plant, and equipment, and negatively impact our business.

In 2012, the EPA finalized rules that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA's rule package included New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds ("VOCs") and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The rules established specific new requirements regarding emissions from compressors and controllers at natural gas processing plants, dehydrators, storage tanks and other production equipment as well as the first federal air standards for natural gas wells that are hydraulically fractured. In June 2016, the EPA took steps to expand on these regulations when it published New Source Performance Standards, known as Subpart OOOOa, that require certain new, modified or reconstructed facilities in the oil and natural gas sector to reduce these methane gas and volatile organic compound emissions. These Subpart OOOOa standards will expand the 2012 New Source Performance Standards by using certain equipment-specific emissions control practices, requiring additional controls for pneumatic controllers and pumps as well as compressors, and imposing leak detection and repair requirements for natural gas compressor and booster

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stations. However, the EPA announced in April 2017 that it intends to reconsider certain aspects of the 2016 New Source Performance Standards, and in May 2017, the EPA issued an administrative stay of key provisions of the rule, but was promptly ordered by the D.C. Circuit to implement the rule. The EPA also proposed 60-day and two-year stays of certain provisions in June 2017 and published a Notice of Data Availability in November 2017 seeking comment and providing clarification regarding the agency's legal authority to stay the rule.

If implemented, Subpart OOOOa and any additional regulation of air emissions from the oil and gas sector could result in increased expenditures for pollution control equipment, which could impact our customers' operations and negatively impact our business.

Climate change legislation and regulatory initiatives could result in increased compliance costs.

Climate change continues to attract considerable public and scientific attention. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of natural gas, are examples of greenhouse gases. In recent years, the U.S. Congress has considered legislation to reduce emissions of greenhouse gases. It presently appears unlikely that comprehensive climate legislation will be passed by either house of Congress in the near future, although energy legislation and other initiatives are expected to be proposed that may be relevant to greenhouse gas emissions issues. However, almost half of the states have begun to address greenhouse gas emissions, primarily through the planned development of emission inventories or regional greenhouse gas cap and trade programs. Depending on the particular program, we could be required to control greenhouse gas emissions or to purchase and surrender allowances for greenhouse gas emissions resulting from our operations.

Independent of Congress, and as discussed in detail in Item 1 ("Business Environmental and Safety Regulations"), the EPA undertook to adopt regulations controlling greenhouse gas emissions under its existing CAA authority. For example, in 2015, the EPA published standards of performance for greenhouse gas emissions from new power plants. The final rule establishes a performance standard for integrated gasification combined cycled units and utility boilers based on the use of the best system of emission reduction that EPA has determined has been adequately demonstrated for each type of unit. The rule also sets limits for stationary natural gas combustion turbines based on the use of natural gas combined cycle technology. The EPA also promulgated the Clean Power Plan rule, which is intended to reduce carbon emissions from existing power plants by 32 percent from 2005 levels by 2030. In February 2016, the U.S. Supreme Court granted a stay of the implementation of the Clean Power Plan, which will remain in effect throughout the pendency of the appeals process including at the United States Court of Appeals of the D.C. Circuit and the Supreme Court through any certiorari petition that may be granted. The stay suspends the rule, including the requirement that states must start submitting implementation plans. Additionally, in October 2017 EPA proposed to repeal the CPP, although the final outcome of this action and the pending litigation regarding the CPP is uncertain at this time. In connection with the proposed repeal, EPA issued an Advance Notice of Proposed Rulemaking ("ANPRM") in December 2017 regarding emission guidelines to limit GHG emissions from existing electricity utility generating units. The ANPRM seeks comment regarding what the EPA should include in a potential new, existing-source regulation under the Clean Air Act of GHG emissions from electric utility generating units that it may propose. If the effort to repeal the rules is unsuccessful and the rules are upheld at the conclusion of this appellate process and enforced in their current form, or if the ANPRM results in a different proposal to control GHG emissions from electric utility generating units, demand for the oil and natural gas our customers produce may decrease.

Although it is not currently possible to predict with specificity how any proposed or future greenhouse gas legislation, regulation, agreements or initiatives will impact our business, any legislation or regulation of greenhouse gas emissions that may be imposed in areas in which we conduct business could result in increased compliance costs or additional operating restrictions or reduced demand for our services, and could have a material adverse effect on our business, financial condition and results of operations.

Finally, it should be noted that some scientists have concluded that increasing concentrations of GHG 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 of those effects were to occur, they could have an adverse effect on our assets and operations.

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Increased regulation of hydraulic fracturing could result in reductions or delays in natural gas production by our customers, which could adversely impact our revenue.

A significant portion of our customers' natural gas production is developed from unconventional sources that require hydraulic fracturing as part of the completion process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into the formation to stimulate gas production. Legislation to amend the Safe Drinking Water Act ("SDWA") to repeal the exemption for hydraulic fracturing from the definition of "underground injection" and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, have been proposed and the U.S. Congress continues to consider legislation to amend the SDWA. Scrutiny of hydraulic fracturing activities continues in other ways, with the EPA having commenced a multi-year study of 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 concluded that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources "under some circumstances," noting that the following hydraulic fracturing water cycle activities and local- or regional-scale factors are more likely than others to result in more frequent or more severe impacts: water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits.

State and federal regulatory agencies have also recently focused on a possible connection between the operation of injection wells used for oil and gas waste disposal and seismic activity. Similar concerns have been raised that hydraulic fracturing may also contribute to seismic activity. When caused by human activity, such events are called induced seismicity. Developing research suggests that the link between seismic activity and wastewater disposal may vary by region, and that only a very small fraction of the tens of thousands of injection wells have been suspected to be, or have been, the likely cause of induced seismicity. In March 2016, the United States Geological Survey identified six states with the most significant hazards from induced seismicity, including Oklahoma, Kansas, Texas, Colorado, New Mexico, and Arkansas. In light of these concerns, some state regulatory agencies have modified their regulations or issued orders to address induced seismicity. Increased regulation and attention given to induced seismicity could lead to greater opposition to, and litigation concerning, oil and gas activities utilizing hydraulic fracturing or injection wells for waste disposal, which could indirectly impact our business, financial condition and results of operations. In addition, these concerns may give rise to private tort suits against our customers from individuals who claim they are adversely impacted by seismic activity they allege was induced. Such claims or actions could result in liability to our customers for property damage, exposure to waste and other hazardous materials, nuisance or personal injuries, and require our customers to expend additional resources or incur substantial costs or losses. This could in turn adversely affect the demand for our services.

We cannot predict the future of any such legislation or tort liability. If additional levels of regulation, restrictions and permits were required through the adoption of new laws and regulations at the federal or state level or the development of new interpretations of those requirements by the agencies that issue the permits, that could lead to delays, increased operating costs and process prohibitions that could reduce demand for our compression services, which would materially adversely affect our revenue and results of operations.

We do not insure against all potential losses and could be seriously harmed by unexpected liabilities.

Our operations are subject to inherent risks such as equipment defects, malfunction and failures, and natural disasters that can result in uncontrollable flows of gas or well fluids, fires and explosions. These risks could expose us to substantial liability for personal injury, death, property damage, pollution and other environmental damages. Our insurance may be inadequate to cover our liabilities. Further, insurance covering the risks we face or in the amounts we desire may not be available in the future or, if available, the premiums may not be commercially justifiable. If we were to incur substantial liability and such damages were not covered by insurance or were in excess of policy limits, or if we were to incur liability at a time when we are not able to obtain liability insurance, our business, results of operations and financial condition could be adversely affected.

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Terrorist attacks, the threat of terrorist attacks or other sustained military campaigns may adversely impact our results of operations.

The long-term impact of terrorist attacks and the magnitude of the threat of future terrorist attacks on the energy industry in general and on us in particular are not known at this time. Uncertainty surrounding sustained military campaigns may affect our operations in unpredictable ways, including disruptions of crude oil and natural gas supplies and markets for crude oil, natural gas and natural gas liquids and the possibility that infrastructure facilities could be direct targets of, or indirect casualties of, an act of terror. Changes in the insurance markets attributable to terrorist attacks may make certain types of insurance more difficult for us to obtain, if we choose to do so. Moreover, the insurance that may be available to us may be significantly more expensive than our existing insurance coverage. Instability in the financial markets as a result of terrorism or war could also affect our ability to raise capital.

If we fail to develop or maintain an effective system of internal controls, we may not be able to report our financial results accurately or prevent fraud, which would likely have a negative impact on the market price of our units.

In connection with the closing of our initial public offering, we became subject to the public reporting requirements of the Exchange Act. Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and to operate successfully as a publicly traded partnership. We continue to evaluate the effectiveness of and improve upon our internal controls. Our efforts to develop and maintain our internal controls may not be successful, and we may be unable to maintain effective controls over our financial processes and reporting in the future or to comply with our obligations under Section 404 of the Sarbanes Oxley Act of 2002 (“Section 404”). For example, Section 404 requires us, among other things, to review and report annually on the effectiveness of our internal control over financial reporting. We were required to comply with Section 404(a) beginning with our fiscal year ended December 31, 2013. In addition, our independent registered public accountants will be required to assess the effectiveness of internal control over financial reporting at the end of the fiscal year after we are no longer an “emerging growth company” under the Jumpstart Our Business Startups Act, which will occur at the end of 2018. Any failure to develop, implement or maintain effective internal controls or to improve our internal controls could harm our operating results or cause us to fail to meet our reporting obligations. Given the difficulties inherent in the design and operation of internal controls over financial reporting, we can provide no assurance as to our independent registered public accounting firm’s conclusions about the effectiveness of our internal controls, and we may incur significant costs in our efforts to comply with Section 404. Ineffective internal controls will subject us to regulatory scrutiny and a loss of confidence in our reported financial information, which could have an adverse effect on our business and would likely have a negative effect on the trading price of our units.

Risks Inherent in an Investment in Us

Holders of our common units have limited voting rights and are not entitled to elect our general partner or its directors.

Unlike the holders of common stock in a corporation, our unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Unitholders have no right to elect our general partner or its board of directors. USA Compression Holdings is the sole member of our general partner and has the right to appoint our general partner's entire board of directors, including its independent directors. If the unitholders are dissatisfied with the performance of our general partner, they have little ability to remove our general partner. As a result of these limitations, the price of our common units may be diminished because of the absence or reduction of a takeover premium in the trading price. Furthermore, our partnership agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management. If the GP Purchase is completed, all of the risks relative to USA Compression Holdings in this paragraph will subsequently apply to the Energy Transfer Parties.

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The owner of our general partner has sole responsibility for conducting our business and managing our operations. Our general partner and its affiliates, including the owner thereof, have conflicts of interest with us and limited fiduciary duties and they may favor their own interests to the detriment of us and our unitholders.

USA Compression Holdings, which is principally owned and controlled by Riverstone, owns and controls our general partner and appointed all of the officers and directors of our general partner, some of whom are also officers and directors of USA Compression Holdings. Although our general partner has a fiduciary 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 its owner. Conflicts of interest will arise between our general partner and its owner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of its owner 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 the owner of our general partner to pursue a business strategy that favors us;

· our general partner is allowed to take into account the interests of parties other than us, such as its owner, in resolving conflicts of interest;

· our partnership agreement limits the liability of and reduces the fiduciary duties owed by our general partner, and also restricts the remedies available to our unitholders for actions that, without such limitations, might constitute breaches of fiduciary duty;

· except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval;

· our general partner determines the amount and timing of asset purchases and sales, borrowings, issuance of additional partnership interests and the creation, reduction or increase of reserves, each of which can affect the amount of cash that is distributed to our unitholders;

· our general partner determines the amount and timing of any capital expenditures and whether a capital expenditure is classified as a maintenance capital expenditure, which reduces operating surplus, or an expansion capital expenditure, which does not reduce operating surplus. This determination can affect the amount of cash that is distributed to our unitholders and to our general partner;

· our general partner determines which costs incurred by it are reimbursable by us;

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our general partner may cause us to borrow funds in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make incentive distributions;

- our partnership agreement permits us to classify up to $36.6 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 as operating surplus from non-operating sources to our general partner in respect of its General Partner Interest (as defined under Part II, Item 5 ("Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities") or the incentive distribution rights (or "IDRs");

- our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf;

- our general partner intends to limit its liability regarding our contractual and other obligations;

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- our general partner may exercise its right to call and purchase all of the common units not owned by it and its affiliates if they own more than 80% of the common units;

- our general partner controls the enforcement of the obligations that it and its affiliates owe to us;

- our general partner decides whether to retain separate counsel, accountants or others to perform services for us; and

- our general partner may elect to cause us to issue common units to it in connection with a resetting of the target distribution levels related to the IDRs without the approval of the conflicts committee of the board of directors of our general partner or our unitholders. This election may result in lower distributions to our common unitholders in certain situations.

Our general partner’s liability regarding our obligations is limited.

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

Our partnership agreement limits our general partner’s fiduciary duties to our unitholders.

Our partnership agreement contains provisions that modify and reduce 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 its capacity as our general partner, or otherwise free of fiduciary duties to us and our unitholders. This entitles our general partner to consider only the interests and factors that it desires and relieves it of any duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or our limited partners. Examples of decisions that our general partner may make in its individual capacity include:

- how to allocate business opportunities among us and its affiliates;

- whether to exercise its limited call right;

- how to exercise its voting rights with respect to the units it owns;

- whether to elect to reset target distribution levels; and

- whether or not to consent to any merger or consolidation of the Partnership or amendment to the partnership agreement.

By purchasing a unit, a unitholder agrees to become bound by the provisions in the partnership agreement, including the provisions discussed above.

Even if holders of our common units are dissatisfied, they currently cannot remove our general partner without USA Compression Holdings' consent.

The unitholders are currently unable to remove our general partner because our general partner and its affiliates own sufficient units to be able to prevent its removal. The vote of the holders of at least 662/3% of all outstanding common units is required to remove our general partner. USA Compression Holdings currently owns over 331/3% of our outstanding common units and, after giving effect to the CDM Acquisition and the other transactions described in Item 1 ("Business—Recent Developments"), the Energy Transfer Parties will own over 331/3% of our outstanding common units.

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 makes a determination or takes, or declines to take, any other action in its capacity as our general partner, our general partner is required to make such determination, or take or decline to take such other action, in good faith, and will not be subject to any higher 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 such decisions are made in good faith, meaning that it believed that the decisions were in the best 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:

(a) 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;

(b) approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner and its affiliates;

(c) on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or

(d) fair and reasonable to us, taking into account the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to us.

In connection with a situation involving a transaction with an affiliate or a conflict of interest, any determination by our general partner must be made in good faith. If an affiliate transaction or the resolution of a conflict of interest is not approved by our common unitholders or the conflicts committee and the board of directors of our general partner determines that the resolution or course of action taken with respect to the affiliate transaction or conflict of interest satisfies either of the standards set forth in subclauses (c) and (d) above, then it will conclusively be deemed that, in making its decision, the board of directors of our general partner acted in good faith.

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

Our general partner has the right, at any time when it has received incentive distributions at the highest level to which it is entitled (48.0%) for each of the prior four consecutive fiscal quarters, 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 by our general partner, 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 our general partner elects to reset the target distribution levels, it will be entitled to receive a number of common units and to maintain its general partner interest. The number of common units to be issued to our general partner will equal the number of common units which would have entitled the holder to an average aggregate quarterly cash distribution in the prior two quarters equal to the average of the distributions to our general partner on the IDRs in the prior two quarters. Our general partner's general partner interest in us (currently 1.2%) will be maintained at the percentage that existed immediately prior to the reset election. Our general partner 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 IDRs 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. 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. On January 15, 2018, our general partner entered into an agreement pursuant to which it agreed to, among other things, convert the General Partner Interest into a non-economic general partner interest and cancel the IDRs. The transactions are expected to close in the first half of 2018. See Item 1 ("Business—Recent Developments") for more information.

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

Unitholders' voting rights are further restricted by a provision of our partnership agreement providing that any 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, their direct transferees and their indirect transferees approved by our general partner (which approval may be granted in its sole discretion) and persons who acquired such units with the prior approval of our general partner, cannot vote on any matter.

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

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, our partnership agreement does not restrict the ability of USA Compression Holdings to transfer all or a portion of its ownership interest in our general partner to a third party. The new owner of our general partner would then be in a position to replace the board of directors and officers of our general partner with its own designees and thereby exert significant control over the decisions made by the board of directors and officers of our general partner. On January 15, 2018, USA Compression Holdings entered into an agreement pursuant to which it agreed to, among other things, sell 100% of its ownership interests in our general partner to ETE. The transactions are expected to close in the first half of 2018. See Item 1 (“Business—Recent Developments”) for more information.

An increase in interest rates may cause the market price of our common units to decline.

Like all equity investments, an investment in our common units is subject to certain risks. In exchange for accepting these risks, investors may expect to receive a higher rate of return than would otherwise be obtainable from lower-risk investments. Accordingly, as interest rates rise, the ability of investors to obtain higher risk-adjusted rates of return by purchasing government-backed debt securities may cause a corresponding decline in demand for riskier investments

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generally, including yield based equity investments such as publicly traded partnership interests. Reduced demand for our common units resulting from investors seeking other more favorable investment opportunities may cause the trading price of our common units to decline.

We may issue additional units without the approval of the common unitholders, which would dilute your existing ownership interests.

Our partnership agreement does not limit the number or timing of additional limited partner interests that we may issue without the approval of our common unitholders. The issuance by us of additional common units, including pursuant to our Distribution Reinvestment Plan (“DRIP”), or other equity securities of equal or senior rank, will have the following effects:

- our existing unitholders’ proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each unit may decrease;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished;
- the market price of the common units may decline;
- assuming the distribution per unit remains unchanged or increases, the cash distributions to the holder of the IDRs will increase; and
- On January 15, 2018, we entered into an agreement pursuant to which we agreed, among other things, to issue Preferred Units to certain investors. The transactions are expected to close in the first half of 2018. See Item 1 (“Business—Recent Developments”) for more information.

USA Compression Holdings, Argonaut and the Energy Transfer Parties may sell units in the public or private markets, and such sales could have an adverse impact on the trading price of the common units.

As of December 31, 2017, USA Compression Holdings holds an aggregate of 25,092,196 common units. Argonaut Private Equity, L.L.C. (“Argonaut”) holds an aggregate of 7,715,948 common units. In addition, USA Compression Holdings and Argonaut may acquire additional common units in connection with our DRIP. After giving effect to the CDM Acquisition and the other transactions described in Item 1 (“Business—Recent Developments”), the Energy Transfer Parties will own an aggregate of 46,056,228 common units (after giving effect to the conversion of 6,397,965 Class B Units representing limited partner interests in the Partnership), and USA Compression Holdings will own an aggregate of 12,625,284 common units. We have agreed to provide USA Compression Holdings and the Energy Transfer Parties with certain registration rights for any common units they own. The sale of these common units in the public or private markets could have an adverse impact on the price of the common units or on any trading market that may develop.

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

If at any time our general partner and its affiliates own more than 80% of the common units, our general partner will have the right, which it may assign to any of its affiliates or to us, but not the obligation, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price that is not less than their then-current market price, as calculated pursuant to the terms of our partnership agreement. As a result, you may be required to sell your common units at an undesirable time or price. You may also incur a tax liability upon a sale of your units. USA Compression Holdings owns an aggregate of approximately 40% of our outstanding common units and, after giving effect to the CDM Acquisition and the other transactions described in Item 1 (“Business—Recent Developments”), the Energy Transfer Parties would own an aggregate of approximately 49% of our outstanding common units.

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Your 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 our general partner. Our partnership is organized under Delaware law, and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. You could be liable for any and all of our obligations as if you were a general partner if a court or government agency were to determine that:

- we were conducting business in a state but had not complied with that particular state's partnership statute; or

- your right to act with other unitholders to remove or replace our general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitute "control" of our business.

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

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act (the "Delaware Act"), we may not make a distribution to you if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of an impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Neither liabilities to partners on account of their partnership interest nor liabilities that are non-recourse to the partnership are counted for purposes of determining whether a distribution is permitted.

The NYSE does not require a publicly traded partnership like us to comply with certain of its corporate governance requirements.

Our common units are listed 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 investors in certain corporations that are subject to all of the NYSE corporate governance requirements. Please read Part III, Item 10 ("Directors, Executive Officers and Corporate Governance").

Pursuant to certain federal securities laws, our independent registered public accounting firm will not be required to attest to the effectiveness of our internal control over financial reporting pursuant to Section 404 of the Sarbanes Oxley Act of 2002 for so long as we are an emerging growth company.

We are required to disclose changes made in our internal control over financial reporting on a quarterly basis, and we are required to assess the effectiveness of our controls annually. However, for as long as we are an “emerging growth company” under federal securities laws, our independent registered public accounting firm will not be required to attest to the effectiveness of our internal control over financial reporting pursuant to Section 404. We will be an emerging growth company until the end of the fiscal year ending December 31, 2018. Even if we conclude that our internal control over financial reporting is effective, our independent registered public accounting firm may still decline to attest to our assessment or may issue a report that is qualified if it is not satisfied with our controls or the level at which our controls are documented, designed, operated or reviewed, or if it interprets the relevant requirements differently from us.

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Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes. If the IRS were to treat us as a corporation for federal income tax purposes, then our cash available for distribution would be substantially reduced.

The anticipated after-tax economic benefit of an investment in the common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested a ruling from the IRS on this or any other tax matter affecting us.

Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. Although we do not believe based upon our current operations that we are or will be so treated, a change in our business or a change in current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

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

Our partnership agreement provides that, if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity level taxation for federal, state or local income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.

If we were subjected to a material amount of additional entity level taxation by individual states, it would reduce our cash available for distribution.

Changes in current state law may subject us to additional entity level taxation by individual states. Because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity level taxation through the imposition of state income, franchise and other forms of taxation. For example, we are required to pay the Revised Texas Franchise Tax each year at a maximum effective rate of 0.75% of our “margin”, as defined in the law, apportioned to Texas in the prior year. Imposition of any similar taxes by any other state may substantially reduce the cash available for distribution and, therefore, negatively impact the value of an investment in our common units.

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

The present 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 interpretation at any time. From time to time, members of the U.S. Congress propose and consider such substantive changes to the existing federal income tax laws that affect publicly traded partnerships. Although there is no current legislative proposal, a prior legislative proposal would have eliminated the qualifying income exception to the treatment of all publicly traded partnerships as corporations upon which we rely for our treatment as a partnership for U.S. federal income tax purposes.

In addition, on January 24, 2017, final regulations regarding which activities give rise to qualifying income within the meaning of Section 7704 of the Code (the “Final Regulations”) were published in the Federal Register. The Final Regulations are effective as of January 19, 2017, and apply to taxable years beginning on or after January 19, 2017. We do not believe the Final Regulations affect our ability to be treated as a partnership for U.S. federal income tax purposes.

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However, any modification to the federal income tax laws may be applied retroactively and could make it more difficult or impossible for us to meet the exception for certain publicly traded partnerships to be treated as partnerships for federal income tax purposes. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Any similar or future legislative changes could negatively impact the value of an investment in our common units. You are urged to consult with your own tax advisor with respect to the status of regulatory or administrative developments and proposals and their potential effect on your investment in our common units.

Our unitholders' share of our income will be taxable to them for federal income tax purposes even if they do not receive any cash distributions from us.

Because a unitholder will be treated as a partner to whom we will allocate taxable income that could be different in amount than the cash we distribute, a unitholder's allocable share of our taxable income will be taxable to it, which may require the payment of federal income taxes and, in some cases, state and local income taxes, on its share of our taxable income even if it receives no cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from that income.

We may engage in transactions to de-lever the Partnership and manage our liquidity that may result in income and gain to our unitholders. For example, if we sell assets and use the proceeds to repay existing debt or fund capital expenditures, you may be allocated taxable income and gain resulting from the sale. Further, taking advantage of opportunities to reduce our existing debt, such as debt exchanges, debt repurchases, or modifications of our existing debt could result in "cancellation of indebtedness income" (also referred to as "COD income") being allocated to our unitholders as taxable income. Unitholders may be allocated COD income, and income tax liabilities arising therefrom may exceed cash distributions. The ultimate effect of any such allocations will depend on the unitholder's individual tax position with respect to its units. Unitholders are encouraged to consult their tax advisors with respect to the consequences of potential COD income or other transactions that may result in income and gain to unitholders.

If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted and the cost of any IRS contest will reduce our cash available for distribution.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from the positions we take, and the IRS's positions may ultimately be sustained.

It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS, and the outcome of any IRS contest, may have a materially adverse impact on the market for our common units and the price at which they trade.

In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner because the costs will reduce our cash available for distribution.

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

Pursuant to the Bipartisan Budget Act of 2015, for tax years beginning after December 31, 2017, if the IRS makes audit adjustments to our income tax returns, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustments directly from us. To the extent possible under the new rules, our general partner may elect to either pay the taxes (including any applicable penalties and interest) directly to the IRS or, if we are eligible, issue a revised information statement to each unitholder and former unitholder with respect to an audited and adjusted return. Although our general partner may elect to have our unitholders and former unitholders take such audit adjustment into account and pay any resulting taxes (including applicable penalties or interest) in accordance with their interests in us during the tax year under audit, there can be no assurance that such election will be practical, permissible or effective in all circumstances. As a result, our current unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such unitholders did not own units in us during the tax year under audit. If, as a result of any such audit adjustment, we are required to make payments of taxes,

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penalties and interest, our cash available for distribution to our unitholders might be reduced. These rules are not applicable for tax years beginning on or prior to December 31, 2017.

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

If our unitholders sell common units, they will recognize a gain or loss for federal income tax purposes equal to the difference between the amount realized and their tax basis in those common units. Because distributions in excess of their 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 common units a unitholder sells will, in effect, become taxable income to the unitholder if it sells such common units at a price greater than its tax basis in those common units, even if the price received is less than its original cost. In addition, because the amount realized includes a unitholder's share of our nonrecourse liabilities, a unitholder that sells common units may incur a tax liability in excess of the amount of cash received from the sale.

A substantial portion of the amount realized from a unitholder's sale of our units, whether or not representing gain, may be taxed as ordinary income to such unitholder due to potential recapture items, including depreciation recapture. Thus, a unitholder may recognize both ordinary income and capital loss from the sale of units if the amount realized on a sale of such units is less than such unitholder's adjusted basis in the units. Net capital loss may only offset capital gains and, in the case of individuals, up to $3,000 of ordinary income per year. In the taxable period in which a unitholder sells its units, such unitholder may recognize ordinary income from our allocations of income and gain to such unitholder prior to the sale and from recapture items that generally cannot be offset by any capital loss recognized upon the sale of units.

Unitholders may be subject to a limitation on their ability to deduct interest expense incurred by us.

In general, we are entitled to a deduction for interest paid or accrued on indebtedness properly allocable to our trade or business during our taxable year. However, under the Tax Cuts and Jobs Act, for taxable years beginning after December 31, 2017, our deduction for "business interest" is limited to the sum of our business interest income and 30% of our "adjusted taxable income." For the purposes of this limitation, our adjusted taxable income is computed without regard to any business interest expense or business interest income, and in the case of taxable years beginning before January 1, 2022, any deduction allowable for depreciation, amortization, or depletion.

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

Investment in our common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as IRAs) raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from U.S. federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Further, with respect to taxable years beginning after December 31, 2017, a tax-exempt entity with more than one unrelated trade or business (including by attribution from investment in a partnership such as ours that is engaged in one or more unrelated trade or business) is required to compute the unrelated business taxable income of such tax-exempt entity separately with respect to each such trade or business (including for purposes of determining any net operating loss deduction). As a result, for years beginning after December 31, 2017, it may not be possible for tax-exempt entities to utilize losses from an investment in our partnership to offset unrelated business taxable income from another unrelated trade or business and vice versa. Tax-exempt entities should consult a tax advisor before investing in our common units.

Non-U.S. Unitholders will be subject to U.S. taxes and withholding with respect to their income and gain from owning our units.

Non-U.S. unitholders are generally taxed and subject to income tax filing requirements by the U.S. on income effectively connected with a U.S. trade or business (“effectively connected income”). Income allocated to our unitholders and any gain from the sale of our units will generally be considered to be “effectively connected” with a U.S. trade or business. As a result, distributions to a Non-U.S. unitholder will be subject to withholding at the highest applicable

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effective tax rate and a Non-U.S. unitholder who sells or otherwise disposes of a unit will also be subject to U.S. federal income tax on the gain realized from the sale or disposition of that unit.

The Tax Cuts and Jobs Act imposes a withholding obligation of 10% of the amount realized upon a Non-U.S. unitholder's sale or exchange of an interest in a partnership that is engaged in a U.S. trade or business. However, due to challenges of administering a withholding obligation applicable to open market trading and other complications, the IRS has temporarily suspended the application of this withholding rule to open market transfers of interests in publicly traded partnerships pending promulgation of regulations or other guidance that resolves the challenges. It is not clear if or when such regulations or other guidance will be issued. Non-U.S. unitholders should consult a tax advisor before investing in our common units.

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

Because we cannot match transferors and transferees of common units, we have adopted certain methods for allocating depreciation and amortization deductions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to the use of these methods 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 prorate our items of income, gain, loss and deduction for federal income tax purposes between transferors and transferees of our units each month based upon the ownership of our 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 prorate our items of income, gain, loss and deduction for federal income tax purposes 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. Treasury Regulations allow 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 whose common units are the subject of a securities loan (e.g., a loan to a "short seller" to cover a short sale of common units) may be considered as having disposed of those common units. If so, he would no longer be treated for federal income tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss from the disposition.

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

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

A successful IRS challenge to these methods or allocations could adversely affect the timing or amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain recognized from our unitholders’ sale of common units, 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, you will likely become subject to state and local taxes and income tax return filing requirements in jurisdictions where we operate or own or acquire properties.

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

We currently conduct business in several states, many of which currently impose a personal income tax on individuals. Many of these states also impose an income tax on corporations and other entities. As we make acquisitions or expand our business, we may control assets or conduct business in additional states or foreign jurisdictions that impose a personal income tax. It is your responsibility to file all foreign, federal, state and local tax returns.

Risks Related to the CDM Acquisition

Our pending acquisition of CDM may not be consummated.

Our pending acquisition of CDM is expected to close in the first half of 2018 and is subject to closing conditions. If these conditions are not satisfied or waived, the acquisition will not be consummated. If the closing of the acquisition is substantially delayed or does not occur at all, we may not realize the anticipated benefits of the acquisition fully or at all. Certain of the conditions remaining to be satisfied include:

· the continued accuracy of the representations and warranties contained in the Contribution Agreement;

· the performance by each party of its obligations under the Contribution Agreement; and

· the absence of any order from any governmental authority that enjoins or otherwise prohibits, or of any law being enacted which would enjoin or prohibit, the consummation of the transactions contemplated in the Contribution Agreement.

In addition, the Contribution Agreement may be terminated by mutual written consent of the parties or by either us or ETP (i) if the acquisition has not closed on or before June 30, 2018 (subject to a 90 day extension by either party if the regulatory approvals have not then been obtained or certain other conditions have not been satisfied) (the "Outside Date"), (ii) if the other has breached its obligations under the Contribution Agreement, which breaches have not been cured within 30 days, (iii) if any order from any governmental authority permanently prohibiting the consummation of the transactions contemplated thereby has become final and non-appealable or (iv) if the GP Purchase Agreement is terminated in accordance with its terms.

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The closing of the CDM Acquisition is not subject to a financing condition and the Bridge Loans do not backstop the equity portion of the purchase price.

The closing of the CDM Acquisition is not subject to a financing condition; however, the Series A Purchase Agreement contains a condition to closing that we will have increased the aggregate commitments under our revolving credit facility to (or entered into a similar revolving facility with minimum aggregate commitments of) at least $1.3 billion. The Series A Purchase Agreement, the proceeds of which are to fund a portion of the purchase price of the CDM Acquisition, and the Bridge Loans, which is available to backstop a portion of the CDM Acquisition purchase price that we expect to fund with the net proceeds of other debt financing, is each subject to certain closing conditions. Furthermore, the Bridge Commitment does not backstop the equity portion of the purchase price. The Bridge Commitment will expire upon the earliest to occur of (1) the Outside Date as defined in the Contribution Agreement (as the same may be extended thereunder), (2) the consummation of the CDM Acquisition without use of the Bridge Loans, (3) the termination of the Contribution Agreement in accordance with its terms or (4) September 30, 2018. Although obtaining the equity or debt financing is not a condition to the completion of the CDM Acquisition, our failure to have sufficient funds available to pay the purchase price is likely to result in the failure of the CDM Acquisition to be completed or could require us to sell assets in order to satisfy our obligations to close.

The representations, warranties, and indemnifications by ETP are limited in the Contribution Agreement and our diligence of CDM may not identify all material matters related to CDM; as a result, the assumptions on which our estimates of future results of CDM's business have been based may prove to be incorrect in a number of material ways, resulting in us not realizing the expected benefits of the CDM Acquisition.

The representations and warranties by ETP are limited in the Contribution Agreement and our diligence into CDM's business may not identify all material matters related to CDM. In addition, the Contribution Agreement does not provide any indemnities other than those described therein. As a result, the assumptions on which our estimates of future results of CDM's business have been based may prove to be incorrect in a number of material ways, resulting in us not realizing our expected benefits of the CDM Acquisition, including anticipated increased cash flow.

Financing the CDM Acquisition will substantially increase our indebtedness. We may not be able to obtain debt financing for the acquisition on expected or acceptable terms, which would make the acquisition less accretive.

We intend to finance the CDM Acquisition and related fees and expenses with the proceeds of the issuance of debt and equity, including the private placement of Preferred Units, and, to the extent necessary or desirable, with borrowing under our revolving credit facility, other debt financing, borrowings under the Bridge Loans, and/or cash on hand. After completion of the CDM Acquisition, we expect our total outstanding indebtedness will increase from approximately $782.9 million as of December 31, 2017 to approximately $1.6 billion. The increase in our indebtedness may reduce our flexibility to respond to changing business and economic conditions or to fund capital expenditures or working capital needs.

We intend to raise long term debt in advance of closing of the CDM Acquisition. The assumptions underlying our estimate that the CDM Acquisition will be accretive to our distributable cash flow includes assumptions about the interest rate we will be able to obtain in connection with such long term debt. We may not be able to obtain debt financing for the acquisition on expected or acceptable terms, which would make the acquisition less accretive than anticipated.

The CDM Acquisition could expose us to additional unknown and contingent liabilities.

The acquisition of CDM could expose us to additional unknown and contingent liabilities. We have performed a certain level of due diligence in connection with the CDM Acquisition and have attempted to verify the representations made by ETP, but there may be unknown and contingent liabilities related to CDM of which we are unaware. ETP has not agreed to indemnify us for losses or claims relating to the operation of the business or otherwise except to the limited extent described in the Contribution Agreement. There is a risk that we could ultimately be liable for unknown obligations relating to CDM for which indemnification is not available, which could materially adversely affect our business, results of operations and cash flow.

We may have difficulty attracting, motivating and retaining executives and other employees in light of the CDM Acquisition.

Uncertainty about the effect of the CDM Acquisition on employees of us or CDM may have an adverse effect on us. This uncertainty may impair our ability to attract, retain and motivate personnel until the CDM Acquisition is completed. Employee retention may be particularly challenging during the pendency of the CDM Acquisition, as employees may feel uncertain about their future roles with the combined organization. In addition, we or CDM may have to provide additional compensation in order to retain employees. If employees of us or CDM depart because of issues relating to the uncertainty and difficulty of integration or a desire not to become employees of the combined organization, our ability to realize the anticipated benefits of the CDM Acquisition could be adversely affected.

We are subject to business uncertainties and contractual restrictions while the proposed CDM Acquisition is pending, which could adversely affect our business and operations.

In connection with the pending CDM Acquisition, it is possible that some customers, suppliers and other persons with whom we or CDM have business relationships may delay or defer certain business decisions, or might decide to seek to terminate, change or renegotiate their relationship with us or CDM as a result of the CDM Acquisition, which could negatively affect our revenue, earnings and cash available for distribution, as well as the market price of our common units, regardless of whether the CDM Acquisition is completed.

Under the terms of the Contribution Agreement, we and CDM are each subject to certain restrictions on the conduct of our businesses prior to completing the CDM Acquisition, which may adversely affect our ability to execute certain of our business strategies. Such limitations could negatively affect each party’s business and operations prior to the completion of the CDM Acquisition. Furthermore, the process of planning to integrate the acquired entity for the post-acquisition period can divert management attention and resources and could ultimately have an adverse effect on each party.

We will incur substantial transaction-related costs in connection with the CDM Acquisition.

We expect to incur a number of non-recurring transaction-related costs associated with completing the CDM Acquisition and achieving desired synergies. These fees and costs will be substantial. Non-recurring transaction costs include, but are not limited to, fees paid to legal, financial and accounting advisors, lender and other financing fees, filing fees and printing costs. Additional unanticipated costs may be incurred in the integration of CDM’s business. There can be no assurance that the elimination of certain duplicative costs, as well as the realization of other efficiencies related to the integration of the acquired entity, will offset the incremental transaction-related costs over time. Thus, any net benefit may not be achieved in the near term, the long term or at all.

ITEM 1B.Unresolved Staff Comments

None.

ITEM 2.Properties

We do not currently own or lease any material facilities or properties for storage or maintenance of our compression units. As of December 31, 2017, our headquarters consisted of 12,342 square feet of leased space located at 100 Congress Avenue, Austin, Texas 78701.

ITEM 3.Legal Proceedings

Please refer to Note 13 of our consolidated financial statements included in this report for a description of our Legal Proceedings.

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ITEM 4.Mine Safety Disclosures

None.

PART II

ITEM 5.Market For Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Our Partnership Interests

As of February 8, 2018, we had outstanding 62,194,405 common units, a 1.2% general partner interest ("General Partner Interest") and the IDRs. USA Compression Holdings owns a 100% membership interest in our general partner. As of February 8, 2018, USA Compression Holdings owned approximately 40% of our outstanding common units. Our general partner currently owns the General Partner Interest in us and all of the IDRs. As discussed below under "Selected Information from Our Partnership Agreement—General Partner Interest and IDRs," the IDRs represent the right to receive increasing percentages, up to a maximum of 48%, of the cash we distribute from operating surplus (as defined below) in excess of $0.4888 per unit per quarter. Our common units, which represent limited partner interests in us, are listed on the New York Stock Exchange ("NYSE") under the symbol "USAC."

The following table sets forth high and low sales prices per common unit and cash distributions per common unit to common unitholders for the periods indicated. The last reported sales price for our common units on February 8, 2018, was $17.47.

	Price Range		Cash Distribution Declared Per Common	
Period	High	Low	Unit	Date Paid
First Quarter 2016	$ 11.89	$ 7.03	$ 0.525	May 13, 2016
Second Quarter 2016	$ 16.42	$ 10.50	$ 0.525	August 12, 2016
Third Quarter 2016	$ 18.90	$ 14.02	$ 0.525	November 14, 2016
Fourth Quarter 2016	$ 19.33	$ 15.41	$ 0.525	February 14, 2017
First Quarter 2017	$ 19.78	$ 16.13	$ 0.525	May 12, 2017

Second Quarter 2017	$ 17.85	$ 14.30	$ 0.525	August 11, 2017
Third Quarter 2017	$ 17.84	$ 14.55	$ 0.525	November 10, 2017
Fourth Quarter 2017	$ 17.64	$ 15.48	$ 0.525	February 14, 2018

Holders

At the close of business on February 8, 2018, based on information received from the transfer agent of the common units, we had 54 holders of record of our common units. The number of record holders does not include holders of common units in "street names" or persons, partnerships, associations, corporations or other entities identified in security position listings maintained by depositories.

Selected Information from our Partnership Agreement

Set forth below is a summary of the significant provisions of our partnership agreement that relate to available cash and the General Partner Interest and the IDRs.

Available Cash

Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all of our available cash to unitholders of record on the applicable record date. Our partnership agreement generally defines available cash, for each quarter, as cash on hand at the end of a quarter plus cash on hand resulting from working capital

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borrowings made after the end of the quarter less the amount of reserves established by our general partner to provide for the proper conduct of our business, comply with applicable law, our revolving credit facility or other agreements; and provide funds for distributions to our unitholders for any one or more of the next four quarters. Working capital borrowings are borrowings made under a credit facility, commercial paper facility or other similar financing arrangement, and in all cases are used solely for working capital purposes or to pay distributions to partners and with the intent of the borrower to repay such borrowings within twelve months from sources other than working capital borrowings.

General Partner Interest and IDRs

Our partnership agreement provides that our general partner is entitled to its General Partner Interest of all distributions that we make. Our general partner has the right, but not the obligation, to contribute a proportionate amount of capital to us to maintain its General Partner Interest if we issue additional units. Our general partner's General Partner Interest, and the percentage of our cash distributions to which it is entitled, will be proportionately reduced if we issue additional units in the future (other than the issuance of common units upon a reset of the IDRs) and our general partner does not contribute a proportionate amount of capital to us in order to maintain its General Partner Interest. Our partnership agreement does not require that our general partner fund its capital contribution with cash and our general partner may fund its capital contribution by the contribution to us of common units or other property.

The IDRs represent the right to receive increasing percentages (13.0%, 23.0% and 48.0%) of quarterly distributions of available cash from operating surplus after the target distribution levels have been achieved. Our general partner currently holds the IDRs, but may transfer these rights separately from its General Partner Interest without the consent of our limited partners.

On January 15, 2018, our general partner entered into an agreement pursuant to which it agreed to, among other things, convert the General Partner Interest into a non-economic general partner interest and cancel the IDRs. The transactions are expected to close in the first half of 2018. See Item 1 ("Business—Recent Developments") for more information.

Issuer Purchases of Equity Securities

None.

Sales of Unregistered Securities; Use of Proceeds from Sale of Securities

None.

Equity Compensation Plan

For disclosures regarding securities authorized for issuance under equity compensation plans, see Part III, Item 12 (“Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters”).

ITEM 6.Selected Financial Data

SELECTED HISTORICAL FINANCIAL DATA

In the table below we have presented certain selected financial data for USA Compression Partners, LP for each of the years in the five-year period ended December 31, 2017, which has been derived from our audited consolidated financial statements. The following information should be read together with Management’s Discussion and Analysis of Financial Condition and Results of Operations and the Financial Statements contained in Part II, Item 7.

Our operating results incorporate a number of significant estimates and uncertainties. Such matters could cause the data included herein not to be indicative of our future financial condition or results of operations. A discussion of our critical accounting estimates and how these estimates could impact our future financial condition and results of operations is included in “Management's Discussion and Analysis of Financial Condition and Results of

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Operations” contained in Part II, Item 7 of this report. In addition, a discussion of the risk factors that could affect our business and future financial condition and results of operations is included under Part I, Item 1A (“Risk Factors”) of this report. Additionally, Note 2 – Summary of Significant Accounting Policies and Note 13 – Commitments and Contingencies under Part II, Item 8 (“Financial Statements and Supplementary Data”) of this report provide descriptions of areas where estimates and judgments and contingent liabilities could result in different amounts being recognized in our accompanying consolidated financial statements.

We believe that investors benefit from having access to the same financial measures utilized by management. The following table includes the non-GAAP financial measure of gross operating margin, Adjusted EBITDA and Distributable Cash Flow (or “DCF”). For definitions of gross operating margin, Adjusted EBITDA and DCF, and

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reconciliations of such measures to their most directly comparable financial measures calculated and presented in accordance with GAAP, please read “Non-GAAP Financial Measures” below.

	Year Ended December 31,				
	2017	2016	2015	2014	2013
	(in thousands, except per unit amounts)				
Revenues:					
Contract operations	$ 264,315	$ 246,950	$ 263,816	$ 217,361	$ 150,360
Parts and service	15,907	18,971	6,729	4,148	2,558
Total revenues	280,222	265,921	270,545	221,509	152,918
Costs of operations, exclusive of depreciation and amortization:					
Cost of operations	92,591	88,161	81,539	74,035	48,097
Gross operating margin (1)	187,631	177,760	189,006	147,474	104,821
Other operating and administrative costs and expenses:					
Selling, general and administrative	47,483	44,483	40,950	38,718	27,587
Depreciation and amortization	98,603	92,337	85,238	71,156	52,917
Loss (gain) on disposition of assets	(507)	772	(1,040)	(2,233)	284
Impairment of compression equipment	4,972	5,760	27,274	2,266	203
Impairment of goodwill	—	—	172,189	—	—
Total other operating and administrative costs and expenses	150,551	143,352	324,611	109,907	80,991
Operating income (loss)	37,080	34,408	(135,605)	37,567	23,830
Other income (expense):					
Interest expense, net	(25,129)	(21,087)	(17,605)	(12,529)	(12,488)
Other	27	35	22	11	9
Total other expense	(25,102)	(21,052)	(17,583)	(12,518)	(12,479)
Income (loss) before income tax expense	11,978	13,356	(153,188)	25,049	11,351
Income tax expense	538	421	1,085	103	280
Net income (loss)	11,440	12,935	(154,273)	24,946	11,071
Adjusted EBITDA (1)	$ 155,703	$ 146,648	$ 153,572	$ 114,409	$ 81,130
DCF (1)	$ 118,330	$ 118,329	$ 120,850	$ 85,927	$ 56,210
Basic and diluted net income (loss) per common unit:	$ 0.16	$ 0.27	$ (3.15)	$ 0.60	$ 0.32
Cash distributions declared per common unit	$ 2.10	$ 2.10	$ 2.09	$ 2.01	$ 1.73
Other Financial Data:					
Capital expenditures	$ 129,490	$ 48,665	$ 265,798	$ 404,429	$ 175,393
Cash flows provided by (used in):					
Operating activities	$ 124,644	$ 103,697	$ 117,401	$ 101,891	$ 68,190
Investing activities	$ (105,231)	$ (50,831)	$ (278,158)	$ (380,523)	$ (153,946)

Financing activities	$ (19,431)	$ (52,808)	$ 160,758	$ 278,631	$ 85,756
Balance Sheet Data (at period end):					
Working capital (2)	$ 3,118	$ 16,558	$ (8,455)	$ (44,064)	$ (24,177)
Total assets	$ 1,492,087	$ 1,472,412	$ 1,509,771	$ 1,516,482	$ 1,185,884
Long-term debt	$ 782,902	$ 685,371	$ 729,187	$ 594,864	$ 420,933
Partners' equity	$ 633,853	$ 729,517	$ 718,288	$ 839,520	$ 707,727

(1) Please refer to "—Non-GAAP Financial Measures" section below.
(2) Working capital is defined as current assets minus current liabilities.

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Non-GAAP Financial Measures

Gross Operating Margin

The table above includes gross operating margin, which is a non-GAAP financial measure, and a reconciliation to operating income (loss), its most directly comparable GAAP financial measure. We define gross operating margin as revenue less cost of operations, exclusive of depreciation and amortization expense. We believe that gross operating margin is useful as a supplemental measure of our operating profitability. Gross operating margin is impacted primarily by the pricing trends for service operations and cost of operations, including labor rates for service technicians, volume and per unit costs for lubricant oils, quantity and pricing of routine preventative maintenance on compression units and property tax rates on compression units. Gross operating margin should not be considered an alternative to, or more meaningful than, operating income (loss) or any other measure of financial performance presented in accordance with GAAP. Moreover, gross operating margin as presented may not be comparable to similarly titled measures of other companies. Because we capitalize assets, depreciation and amortization of equipment is a necessary element of our costs. To compensate for the limitations of gross operating margin as a measure of our performance, we believe that it is important to consider operating income (loss) determined under GAAP, as well as gross operating margin, to evaluate our operating profitability.

Adjusted EBITDA

We define EBITDA as net income (loss) before net interest expense, depreciation and amortization expense, and income tax expense. We define Adjusted EBITDA as EBITDA plus impairment of compression equipment, impairment of goodwill, interest income on capital lease, unit-based compensation expense, management fees, severance charges, certain transaction fees, loss (gain) on disposition of assets and other. We view Adjusted EBITDA as one of our primary management tools, and we track this item on a monthly basis both as an absolute amount and as a percentage of revenue compared to the prior month, year-to-date, prior year and to budget. Adjusted EBITDA is used as a supplemental financial measure by our management and external users of our financial statements, such as investors and commercial banks, to assess:

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

- the viability of capital expenditure projects and the overall rates of return on alternative investment opportunities;

- the ability of our assets to generate cash sufficient to make debt payments and to make distributions; and

- our operating performance as compared to those of other companies in our industry without regard to the impact of financing methods and capital structure.

We believe that Adjusted EBITDA provides useful information to investors because, when viewed with our GAAP results and the accompanying reconciliations, it provides a more complete understanding of our performance than GAAP results alone. We also believe that external users of our financial statements benefit from having access to the same financial measures that management uses in evaluating the results of our business.

Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income (loss), operating income (loss), cash flows from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP as measures of operating performance and liquidity. Moreover, our Adjusted EBITDA as presented may not be comparable to similarly titled measures of other companies.

Because we use capital assets, depreciation, impairment of compression equipment and the interest cost of acquiring compression equipment are also necessary elements of our costs. Expense related to unit-based compensation expense associated with equity awards to employees is also a necessary component of our business. Therefore, measures that exclude these elements have material limitations. To compensate for these limitations, we believe that it is important to consider both net income (loss) and net cash provided by operating activities determined under GAAP, as well as

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Adjusted EBITDA, to evaluate our financial performance and our liquidity. Our Adjusted EBITDA excludes some, but not all, items that affect net income (loss) and net cash provided by operating activities, and these measures may vary among companies. Management compensates for the limitations of Adjusted EBITDA as an analytical tool by reviewing the comparable GAAP measures, understanding the differences between the measures and incorporating this knowledge into management's decision making processes.

The following table reconciles Adjusted EBITDA to net income (loss) and net cash provided by operating activities, its most directly comparable GAAP financial measures, for each of the periods presented (in thousands):

	Year Ended December 31,				
	2017	2016	2015	2014	2013
Net income (loss)	$ 11,440	$ 12,935	$ (154,273)	$ 24,946	$ 11,071
Interest expense, net	25,129	21,087	17,605	12,529	12,488
Depreciation and amortization	98,603	92,337	85,238	71,156	52,917
Income tax expense	538	421	1,085	103	280
EBITDA	$ 135,710	$ 126,780	$ (50,345)	$ 108,734	$ 76,756
Impairment of compression equipment (1)	4,972	5,760	27,274	2,266	203
Impairment of goodwill (2)	—	—	172,189	—	—
Interest income on capital lease	1,610	1,492	1,631	1,274	—
Unit-based compensation expense (3)	11,708	10,373	3,863	3,034	1,343
Riverstone management fee (4)	—	—	—	—	49
Transaction expenses for acquisitions (5)	1,406	894	—	1,299	2,142
Severance charges	314	577	—	—	—
Other	490	—	—	—	—
Loss (gain) on disposition of assets and other	(507)	772	(1,040)	(2,198)	637
Adjusted EBITDA	$ 155,703	$ 146,648	$ 153,572	$ 114,409	$ 81,130
Interest expense, net	(25,129)	(21,087)	(17,605)	(12,529)	(12,488)
Income tax expense	(538)	(421)	(1,085)	(103)	(280)
Interest income on capital lease	(1,610)	(1,492)	(1,631)	(1,274)	—
Non-cash interest expense and other	2,186	2,108	1,702	1,189	1,839
Riverstone management fee	—	—	—	—	(49)
Transaction expenses for acquisitions	(1,406)	(894)	—	(1,299)	(2,142)
Severance charges	(314)	(577)	—	—	—
Other	(490)	—	—	—	—
Changes in operating assets and liabilities	(3,758)	(20,588)	(17,552)	1,498	180
Net cash provided by operating activities	$ 124,644	$ 103,697	$ 117,401	$ 101,891	$ 68,190

(1) Represents non-cash charges incurred to write down long-lived assets with recorded values that are not expected to be recovered through future cash flows.

(2) For further discussion of the goodwill impairment we recognized for the year ended December 31, 2015, please refer to Item 7 (“Management’s Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates—Goodwill Impairment Assessments”).

(3) For the years ended December 31, 2017, 2016, 2015, 2014 and 2013, unit-based compensation expense included \$2.5 million, \$2.8 million, \$0.9 million, \$0.5 million and \$0, respectively, of cash payments related to quarterly payments of distribution equivalent rights on outstanding phantom unit awards and \$0.4 million, \$0.1 million, \$0.2 million, \$0.3 million and \$0, respectively, related to the cash portion of any settlement of phantom unit awards upon vesting. The remainder of the unit-based compensation expense for 2017, 2016, 2015 and 2014 is related to non-cash adjustments to the unit-based compensation liability, and for 2013 is related to the non-cash amortization of unit-based compensation in equity.

(4) Represents management fees paid to Riverstone for services performed during 2013. We are no longer responsible for these fees following the closing of our initial public offering in January 2013. As such, we believe it is useful to investors to view our results excluding these fees.

(5) Represents certain transaction expenses related to potential acquisitions and other items. We believe it is useful to investors to exclude these fees.

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Distributable Cash Flow

We define DCF as net income (loss) plus non-cash interest expense, non-cash income tax expense, depreciation and amortization expense, unit-based compensation expense, impairment of compression equipment, impairment of goodwill, certain transaction fees, severance charges, loss (gain) on disposition of assets, proceeds from insurance recovery and other, less maintenance capital expenditures.

We believe DCF is an important measure of operating performance because it allows management, investors and others to compare basic cash flows we generate (prior to any retained cash reserves established by our general partner and the effect of the DRIP) to the cash distributions we expect to pay our unitholders. Using DCF, management can quickly compute the coverage ratio of estimated cash flows to planned cash distributions.

DCF should not be considered an alternative to, or more meaningful than, net income (loss), operating income (loss), cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP as measures of operating performance and liquidity. Moreover, our DCF as presented may not be comparable to similarly titled measures of other companies.

Because we use capital assets, depreciation and impairment of compression equipment, (gain) loss on disposition of assets, and maintenance capital expenditures are necessary elements of our costs. Expense related to unit-based compensation expense associated with equity awards to employees is also a necessary component of our business. Therefore, measures that exclude these elements have material limitations. To compensate for these limitations, we believe that it is important to consider both net income (loss) and net cash provided by operating activities determined under GAAP, as well as DCF, to evaluate our financial performance and our liquidity. Our DCF excludes some, but not all, items that affect net income (loss) and net cash provided by operating activities, and these measures may vary among companies. Management compensates for the limitations of DCF as an analytical tool by reviewing the comparable GAAP measures, understanding the differences between the measures and incorporating this knowledge into management’s decision making processes.

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The following table reconciles DCF to net income (loss) and net cash provided by operating activities, its most directly comparable GAAP financial measures, for each of the periods presented (in thousands):

	Year Ended December 31,				
	2017	2016	2015	2014	2013
Net income (loss)	$ 11,440	$ 12,935	$ (154,273)	$ 24,946	$ 11,071
Plus: Non-cash interest expense	2,186	2,108	1,702	1,224	2,201
Plus: Non-cash income tax expense	278	239	874	—	—
Plus: Depreciation and amortization	98,603	92,337	85,238	71,156	52,917
Plus: Unit-based compensation expense (1)	11,708	10,373	3,863	3,034	1,343
Plus: Impairment of compression equipment	4,972	5,760	27,274	2,266	203
Plus: Impairment of goodwill	—	—	172,189	—	—
Plus: Transaction expenses for acquisitions (2)	1,406	894	—	1,299	2,142
Plus: Severance charges	314	577	—	—	—
Plus: Other	490	—	—	—	—
Plus: Loss (gain) on disposition of assets and other	(507)	772	(1,040)	(2,198)	637
Plus: Proceeds from insurance recovery	—	73	1,157	—	—
Less: Maintenance capital expenditures (3)	(12,560)	(7,739)	(16,134)	(15,800)	(14,304)
DCF	$ 118,330	$ 118,329	$ 120,850	$ 85,927	$ 56,210
Plus: Maintenance capital expenditures	12,560	7,739	16,134	15,800	14,304
Plus: Change in working capital	(3,758)	(20,588)	(17,552)	1,498	180
Less: Transaction expenses for acquisitions	(1,406)	(894)	—	(1,299)	(2,142)
Less: Other	(1,082)	(889)	(2,031)	(35)	(362)
Net cash provided by operating activities	$ 124,644	$ 103,697	$ 117,401	$ 101,891	$ 68,190

(1) For the years ended December 31, 2017, 2016, 2015, 2014 and 2013, unit-based compensation expense includes $2.5 million, $2.8 million, $0.9 million, $0.5 million and $0, respectively, of cash payments related to quarterly payments of distribution equivalent rights on phantom unit awards and $0.4 million, $0.1 million, $0.2 million, $0.3 million and $0, respectively, related to the cash portion of any settlement of phantom units upon vesting. The remainder of the unit-based compensation expense for 2017, 2016, 2015 and 2014 is related to non-cash adjustments to the unit-based compensation liability, and for 2013 is related to the non-cash amortization of unit-based compensation in equity.

(2) Represents certain transaction expenses related to potential acquisitions and other items. We believe it is useful to investors to exclude these fees.

(3) Reflects maintenance capital expenditures for the period presented. Maintenance capital expenditures are capital expenditures made to maintain the operating capacity of our assets and extend their useful lives, to replace partially or fully depreciated assets, or other capital expenditures that are incurred in maintaining our existing

business and related operating income.

Coverage Ratios

DCF Coverage Ratio is defined as DCF less cash distributions to be paid to our general partner and IDRs in respect of such period, divided by distributions declared to limited partner unitholders in respect of such period. Cash Coverage Ratio is defined as DCF less cash distributions to be paid to our general partner and IDRs in respect of such period, divided by cash distributions expected to be paid to limited partner unitholders in respect of such period, after taking into account the non-cash impact of the DRIP. We believe DCF Coverage Ratio and Cash Coverage Ratio are important measures of operating performance because they allow management, investors and others to gauge our ability to pay cash distributions to limited partner unitholders using the cash flows that we generate. Our DCF Coverage Ratio and Cash Coverage Ratio as presented may not be comparable to similarly titled measures of other companies.

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The following table summarizes our coverage ratios for the periods presented (dollars in thousands):

	Year Ended December 31,				
	2017	2016	2015	2014	2013
DCF	$ 118,330	$ 118,329	$ 120,850	$ 85,927	$ 56,210
General partner interest in DCF	3,007	2,866	2,658	1,947	1,188
Pre-IPO DCF	—	—	—	—	2,323
DCF attributable to limited partner interest	$ 115,323	$ 115,463	$ 118,192	$ 83,980	$ 52,699
Distributions for DCF coverage ratio (1)	$ 129,657	$ 115,881	$ 101,266	$ 85,098	$ 55,961
Distributions reinvested in the DRIP (2)	16,592	24,441	55,489	52,556	36,694
Distributions for Cash Coverage Ratio (3)	$ 113,065	$ 91,440	$ 45,777	$ 32,542	$ 19,267
DCF Coverage Ratio (4)	0.89	1.00	1.17	0.99	0.94
Cash Coverage Ratio (5)	1.02	1.26	2.58	2.58	2.74

(1) Represents distributions to the holders of our limited partnership units, after giving effect to the weighted average common units outstanding, due to our December 2016, September 2015 and May 2014 equity offerings and an acquisition we completed in August 2013 for the years ended December 31, 2016, 2015, 2014 and 2013, as applicable. Without giving effect to the weighted average common units outstanding due to our December 2016, September 2015 and May 2014 equity offerings and an acquisition we completed in August 2013 for the years ended December 31, 2016, 2015, 2014 and 2013, actual distributions to holders of our limited partnership units were $118.1 million, $103.1 million, $86.5 million and $58.2 million, respectively.

(2) Represents distributions to holders enrolled in the DRIP as of the record date for each period.

(3) Represents cash distributions declared for our limited partnership units not participating in the DRIP, after giving effect to the weighted average of limited partnership units outstanding for each period due to our December 2016, September 2015 and May 2014 equity offerings and an acquisition we completed in August 2013 for the years ended December 31, 2016, 2015, 2014 and 2013, as applicable.

(4) For the years ended December 31, 2016, 2015, 2014 and 2013, the DCF Coverage Ratio based on actual limited partnership units outstanding as of the respective record dates was 0.98x, 1.15x, 0.97x and 0.91x, respectively.

(5) For the years ended December 31, 2016, 2015, 2014 and 2013, the Cash Coverage Ratio based on actual limited partnership units outstanding as of the respective record dates was 1.23x, 2.48x, 2.46x and 2.74x, respectively.

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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, the notes thereto, and the other financial information appearing elsewhere in this report. The following discussion includes forward-looking statements that involve certain risks and uncertainties. See Part I ("Disclosure Regarding Forward-Looking Statements") and Part I, Item 1A ("Risk Factors").

Overview

We provide compression services in a number of shale plays throughout the U.S., including the Utica, Marcellus, Permian Basin, Delaware Basin, Eagle Ford, Mississippi Lime, Granite Wash, Woodford, Barnett, Haynesville, Niobrara and Fayetteville shales. The demand for our services is driven by the domestic production of natural gas and crude oil; as such, we have focused our activities in areas of attractive natural gas and crude oil production growth, which are generally found in these shale and unconventional resource plays. According to studies promulgated by the Energy Information Agency ("EIA"), the production and transportation volumes in these shale plays are expected to increase over the long term due to the comparatively attractive economic returns versus returns achieved in many conventional basins. Furthermore, the changes in production volumes and pressures of shale plays over time require a wider range of compression services than in conventional basins. We believe the flexibility of our compression units positions us well to meet these changing operating conditions. While our business focuses largely on compression services serving infrastructure applications, including centralized natural gas gathering systems and processing facilities, which utilize large horsepower compression units, typically in shale plays, we also provide compression services in more mature conventional basins, including gas lift applications on crude oil wells targeted by horizontal drilling techniques. Gas lift, a process by which natural gas is injected into the production tubing of an existing producing well, thus reducing the hydrostatic pressure and allowing the oil to flow at a higher rate, and other artificial lift technologies are critical to the enhancement of oil production from horizontal wells operating in tight shale plays.

General Trends and Outlook

While our business does not have direct exposure to commodity prices, the general activity levels of our customers can be affected by commodity prices. A significant amount of our assets are utilized in natural gas infrastructure applications, primarily in centralized natural gas gathering systems and processing facilities. Given the project nature of these applications and long-term investment horizon of our customers, we have generally experienced stability in rates and higher sustained utilization rates relative to other businesses more tied to drilling activity and wellhead economics. In addition to assets utilized in infrastructure applications, a small portion of our fleet is used in connection with crude oil production using horizontal drilling techniques.

The relative increase in, and stabilization of, commodity prices during the second-half of 2016 and throughout 2017 has allowed our customers to increase their capital budgets in regards to crude oil exploration and production activities and the build-out of large-scale natural gas infrastructure projects, particularly in areas with favorable economics. These projects increased demand for our compression services throughout 2017 as we saw our horsepower utilization increase from 87.1% at December 31, 2016 to 94.8% at December 31, 2017, while also increasing the horsepower in our fleet from 1,720,547 at December 31, 2016 to 1,799,781 at December 31, 2017.

The U.S. Energy Information Administration January 2018 Short-Term Energy Outlook ("EIA Outlook") expects dry natural gas production to rise by 6.9 billion cubic feet per day ("Bcf/day") in 2018 and by 2.6 Bcf/day in 2019. If achieved, the forecasted 6.9 Bcf/day increase in 2018 would be the highest on record for any single year. The EIA Outlook expects growth to be concentrated in Appalachia's Marcellus and Utica regions, along with the Permian Basin region, all regions in which we provide compression services. Much of the expected increase in natural gas production is the result of increasing pipeline takeaway capacity out of the Marcellus and Utica producing regions to end-use markets. Additionally, EIA Outlook projects liquefied natural gas ("LNG") gross exports will average 3.0 Bcf/day in 2018, up from 1.9 Bcf/day in 2017. The EIA Outlook expects U.S. liquefaction capacity will continue to expand as several new projects are expected to enter service during 2018 and 2019. Also from the EIA Outlook, natural gas pipeline exports to Mexico through October increased by 0.4 Bcf/day in 2017 compared to the same period in 2016. A relatively low natural gas export price, rising demand from Mexico’s power sector, and increased pipeline capacity in both the U.S. and Mexico have led to increased exports.

We believe this increasing demand for natural gas will also create increasing demand for compression services, for both existing natural gas fields as they age and for the development of new natural gas fields. As such, we expect demand for our compression services to continue to increase throughout 2018 although we cannot predict any possible changes in such demand with reasonable certainty.

We intend to prudently deploy capital for new compressor units in 2018. We have already entered into commitments to purchase most of our large horsepower compressor units in 2018, as the lead time to build these units is approximately one year or shorter. Most of our 2018 purchases of large horsepower compressor units are already committed to customers or under contract with customers due to the high demand and limited supply of these units.

The EIA Outlook forecasts total U.S. crude oil production to average 10.3 million barrels per day in 2018, up 1.0 million barrels per day from 2017. If achieved, forecasted 2018 production would be the highest annual average on record, surpassing the previous record of 9.6 million barrels per day set in 1970. According to the EIA Outlook, in 2019, crude oil production is forecast to rise to an average of 10.8 million barrels per day and the Permian region is expected to produce 3.6 million barrels per day of crude oil by the end of 2019 which would represent about 32% of U.S. crude oil production that year. With the large geographic area of the Permian region and stacked plays, the EIA Outlook estimates that operators can continue to develop multiple tight oil layers and increase production, even with sustained crude oil prices lower than $50 per barrel. As of February 8, 2018, the WTI crude oil spot price was $61.15 per barrel. WTI crude oil spot prices are forecast within the EIA Outlook to average $56 per barrel in 2018 and $57 per barrel in 2019. Daily and monthly average crude oil prices could vary significantly from annual average forecasts due to global economic developments and geopolitical events in the coming months that could have the potential to push oil prices higher or lower than forecast. Uncertainty remains regarding the duration of, and adherence to, the current Organization of the Petroleum Exporting Countries (“OPEC”) production cuts, which could influence prices in either direction.

We believe the relative increase in, and stabilization of, crude oil prices in the second half of 2016 and throughout 2017 has led to an increase in drilling activity, and combined with the continued development of horizontal drilling technology, operators are able to produce new volumes of crude oil from tight, high pressure reservoirs. Due in part to these higher initial pressures, the increase in demand for gas lift compression in these new areas of drilling could be delayed until reservoir pressures decline to a point where compression is beneficial to the economics of a particular well or basin. However, we have experienced an increase in the demand for our smaller horsepower units engaged in gas lift applications and expect that to continue.

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Operating Highlights

The following table summarizes certain horsepower and horsepower utilization percentages for the periods presented.

	Year Ended December 31,			Percent Change	
Operating Data:	2017	2016	2015	2017	2016
Fleet horsepower (at period end) (1)	1,799,781	1,720,547	1,712,196	4.6 %	0.5 %
Total available horsepower (at period end) (2)	1,950,301	1,730,547	1,712,196	12.7 %	1.1 %
Revenue generating horsepower (at period end) (3)	1,624,377	1,387,073	1,424,537	17.1 %	(2.6) %
Average revenue generating horsepower (4)	1,505,657	1,377,966	1,408,689	9.3 %	(2.2) %
Average revenue per revenue generating horsepower per month (5)	$ 15.07	$ 15.41	$ 15.90	(2.2) %	(3.1) %
Revenue generating compression units (at period end)	2,830	2,552	2,737	10.9 %	(6.8) %
Average horsepower per revenue generating compression unit (6)	554	534	517	3.7 %	3.3 %
Horsepower utilization (7):					
At period end	94.8 %	87.1 %	89.2 %	8.8 %	(2.4) %
Average for the period (8)	92.0 %	87.4 %	90.5 %	5.3 %	(3.4) %

(1) Fleet horsepower is horsepower for compression units that have been delivered to us (and excludes units on order). As of December 31, 2017, we had 147,500 and 5,520 horsepower on order for delivery during 2018 and 2019, respectively.
(2) Total available horsepower is revenue generating horsepower under contract for which we are billing a customer, horsepower in our fleet that is under contract but is not yet generating revenue, horsepower not yet in our fleet that is under contract but not yet generating revenue and that is subject to a purchase order, and idle horsepower. Total available horsepower excludes new horsepower on order for which we do not have a compression services contract.
(3) Revenue generating horsepower is horsepower under contract for which we are billing a customer.
(4) Calculated as the average of the month-end revenue generating horsepower for each of the months in the period.
(5) Calculated as the average of the result of dividing the contractual monthly rate for all units at the end of each month in the period by the sum of the revenue generating horsepower at the end of each month in the period.
(6) Calculated as the average of the month-end revenue generating horsepower per revenue generating compression unit for each of the months in the period.
(7) Horsepower utilization is calculated as (i) the sum of (a) revenue generating horsepower, (b) horsepower in our fleet that is under contract but is not yet generating revenue, and (c) horsepower not yet in our fleet that is under contract, not yet generating revenue and that is subject to a purchase order, divided by (ii) total available horsepower less idle horsepower that is under repair. Horsepower utilization based on revenue generating horsepower and fleet horsepower was 90.3%, 80.6% and 83.2% at December 31, 2017, 2016 and 2015, respectively.
(8) Calculated as the average utilization for the months in the period based on utilization at the end of each month in the period. Average horsepower utilization based on revenue generating horsepower and fleet horsepower was 85.9%, 80.3% and 85.1% for the years ended December 31, 2017, 2016 and 2015, respectively.

The 4.6% increase in fleet horsepower as of December 31, 2017 over the fleet horsepower as of December 31, 2016 was attributable to new compression units added to our fleet to meet then expected demand by new and current customers for compression services. The 17.1% increase in revenue generating horsepower as of December 31, 2017 over December 31, 2016 was primarily due to organic growth in our active fleet and redeployment of previously idle equipment. The 3.7% increase in average horsepower per revenue generating compression unit as of December 31, 2017 over December 31, 2016 was primarily due to the addition of large horsepower compression units in the operating fleet. The 2.2% decrease in average revenue per revenue generating horsepower per month for the year ended December 31, 2017 over December 31, 2016 was primarily due to (1) reduced pricing in the small horsepower portion of our fleet in the current period and (2) an increase in the average horsepower per revenue generating compression unit in the current period, resulting from an increase in the number of large horsepower compression units which typically generate lower average revenue per revenue generating horsepower than do small horsepower compression units.

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The 0.5% increase in fleet horsepower as of December 31, 2016 over the fleet horsepower as of December 31, 2015 was attributable to new compression units added to our fleet to meet then expected demand by new and current customers for compression services. The 2.6% decrease in revenue generating horsepower as of December 31, 2016 over December 31, 2015 was primarily due to an increase in the amount of time required to contract services for new compression units and an increase in the amount of compression units returned to us. The 3.3% increase in average horsepower per revenue generating compression unit as of December 31, 2016 over December 31, 2015 was primarily due to the addition of large horsepower compression units in the operating fleet and the decline in utilization of small horsepower units over the year ended December 31, 2016. The 3.1% decrease in average revenue per revenue generating horsepower per month for the year ended December 31, 2016 over December 31, 2015 was primarily due to (1) reduced pricing in the small horsepower portion of our fleet in the current period and (2) an increase in the average horsepower per revenue generating compression unit in the current period, resulting from an increase in the number of large horsepower compression units which typically generate lower average revenue per revenue generating horsepower than do small horsepower compression units.

Average horsepower utilization increased to 92.0% during the year ended December 31, 2017 compared to 87.4% during the year ended December 31, 2016. The 4.6% increase in average horsepower utilization was primarily attributable to the following changes as a percentage of total available horsepower: (1) a 6.9% increase in horsepower that is under contract but not yet generating revenue and (2) a 1.9% decrease in our average fleet of compression units returned to us not yet under contract, offset by (3) a 4.0% decrease in idle horsepower under repair, which is excluded from the average horsepower utilization calculation until such repair is complete. We believe the increase in average horsepower utilization is the result of increased demand for our services commensurate with increased operating activity in the oil and gas industry. The above noted fluctuation in utilization components also describes the changes in period end horsepower utilization as of December 31, 2017 compared to December 31, 2016.

Average horsepower utilization decreased to 87.4% during the year ended December 31, 2016 compared to 90.5% during the year ended December 31, 2015. The 3.1% decrease in average horsepower utilization was primarily attributable to the following changes as a percentage of total available horsepower: (1) a 3.7% increase in our average fleet of compression units returned to us not yet under contract and (2) a 1.0% decrease in horsepower that was on-contract or pending-contract but not yet active. The decrease in average horsepower utilization was offset by a 2.6% increase in idle horsepower under repair, which is excluded from the average horsepower utilization calculation until such repair is complete. We believe the decrease in average horsepower utilization was the result of a delay in planned projects of certain of our customers, continued optimization of existing compression service requirements by our customers and our selective pursuit of what we deemed to be the most attractive opportunities. The above noted fluctuation in utilization components also describes the changes in period end horsepower utilization, except that we experienced a 1.2% increase in horsepower that was on-contract or pending-contract but not yet active as of December 31, 2016 compared to December 31, 2015.

Average horsepower utilization based on revenue generating horsepower and fleet horsepower increased to 85.9% during the year ended December 31, 2017 compared to 80.3% during the year ended December 31, 2016. The 5.6% increase was primarily attributable to the following changes as a percentage of total fleet horsepower: (1) a 4.0% decrease in idle horsepower under repair and (2) a 2.0% decrease in our average idle fleet composed of new compression units offset by (3) a 0.4% increase in our average idle fleet from compression units returned to us. The overall decrease in idle horsepower is the result of increased demand for our services commensurate with increased operating activity in the oil and gas industry. These factors also describe the variances in period end horsepower utilization based on revenue generating horsepower and fleet horsepower between the year ended December 31, 2017 and the year ended December 31, 2016.

Average horsepower utilization based on revenue generating horsepower and fleet horsepower decreased to 80.3% during the year ended December 31, 2016 compared to 85.1% during the year ended December 31, 2015. The 4.8% decrease was primarily attributable to the following changes as a percentage of total fleet horsepower: (1) a 4.7% increase in our average idle fleet from compression units returned to us and (2) a 2.6% increase in idle horsepower under repair offset by (3) a 2.4% decrease in our average idle fleet composed of new compression units. The increase in units returned to us is believed to be a result of our customers' optimization of their compression service requirements. These

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factors also describe the variances in period end horsepower utilization based on revenue generating horsepower and fleet horsepower between the year ended December 31, 2016 and the year ended December 31, 2015.

Financial Results of Operations

Year ended December 31, 2017 compared to the year ended December 31, 2016

The following table summarizes our results of operations for the periods presented (dollars in thousands):

	Year Ended December 31, 2017	2016	Percent Change
Revenues:			
Contract operations	$ 264,315	$ 246,950	7.0 %
Parts and service	15,907	18,971	(16.2) %
Total revenues	280,222	265,921	5.4 %
Costs and expenses:			
Cost of operations, exclusive of depreciation and amortization	92,591	88,161	5.0 %
Gross operating margin	187,631	177,760	5.6 %
Other operating and administrative costs and expenses:			
Selling, general and administrative	47,483	44,483	6.7 %
Depreciation and amortization	98,603	92,337	6.8 %
Loss (gain) on disposition of assets	(507)	772	165.7 %
Impairment of compression equipment	4,972	5,760	(13.7) %
Total other operating and administrative costs and expenses	150,551	143,352	5.0 %
Operating income	37,080	34,408	7.8 %
Other income (expense):			
Interest expense, net	(25,129)	(21,087)	19.2 %
Other	27	35	(22.9) %
Total other expense	(25,102)	(21,052)	19.2 %
Income before income tax expense	11,978	13,356	(10.3) %
Income tax expense	538	421	27.8 %
Net income	$ 11,440	$ 12,935	(11.6) %

Contract operations revenue. During 2017, we experienced a year-to-year increase in demand for our compression services driven by increased operating activity in natural gas and crude oil production, resulting in a $17.4 million increase in our contract operations revenue. Average revenue generating horsepower increased 9.3% during the year ended December 31, 2017 over December 31, 2016 while average revenue per revenue generating horsepower per month decreased from $15.41 for the year ended December 31, 2016 to $15.07 for the year ended December 31, 2017, a decrease of 2.2%, attributable, in part, to reduced pricing in the current period in the small horsepower portion of our fleet. The decrease in average revenue per revenue generating horsepower per month was also attributable to the 3.7% increase in the average horsepower per revenue generating compression unit in the current period, as large horsepower compression units typically generate lower average monthly revenue per revenue generating horsepower than do small horsepower compression units. Average revenue per revenue generating horsepower per month associated with our compression services provided on a month-to-month basis did not significantly differ from the average revenue per revenue generating horsepower per month associated with our compression services provided under contracts in the primary term. Our contract operations revenue was not materially impacted by any renegotiations of our contracts during the period with our customers.

Parts and service revenue. Parts and service revenue was earned primarily on the installation of equipment ancillary to compression operations. The $3.1 million decrease in parts and service revenue was primarily attributable to (1) an $8.3 million decrease in revenue associated with installation services offset by (2) a $4.1 million increase in maintenance work on units at our customers' locations that are outside the scope of our core maintenance activities and (3) a $1.4 million increase in freight and crane charges that are directly reimbursable by our customers. We offer these

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services as a courtesy to our customers and the demand fluctuates from period to period based on the varying needs of our customers.

Cost of operations, exclusive of depreciation and amortization. The $4.4 million increase in cost of operations was primarily attributable to (1) a $7.4 million increase in direct expenses, such as parts and fluids expenses and (2) a $2.4 million increase in direct labor expenses offset by (3) a $3.5 million decrease in retail parts and service expenses, which have a corresponding decrease in parts and service revenue, and (4) a $2.7 million decrease in property and other taxes. The increase in direct parts, fluids and labor are primarily driven by the increase in average revenue generating horsepower during the current period.

Gross operating margin. The $9.9 million increase in gross operating margin was primarily due to an increase in revenues, partially offset by an increase in operating expenses during the year ended December 31, 2017.

Selling, general and administrative expense. The $3.0 million increase in selling, general and administrative expense for the year ended December 31, 2017 was primarily attributable to (1) a $1.3 million increase in unit-based compensation expense, (2) a $0.8 million increase in bad debt expense, due to a $1.1 million recovery of bad debt expense during the year ended December 31, 2016 compared to a $0.3 million recovery during the year ended December 31, 2017 and (3) $0.5 million increase in transaction expenses related to potential acquisitions. Unit-based compensation expense increased primarily due to a greater fair value assigned to the 2016 “Performance Units” that are subject to market criteria and which were measured using the Monte Carlo simulation model as of December 31, 2017.

Depreciation and amortization expense. The $6.3 million increase in depreciation expense was primarily related to an increase in gross property and equipment balances during the year ended December 31, 2017 compared to gross balances during the year ended December 31, 2016.

Loss (gain) on disposition of assets. During the year ended December 31, 2017, the $0.5 million gain was primarily attributable to the sale of select compression equipment. During the year ended December 31, 2016, we abandoned certain assets and incurred a $1.0 million loss.

Impairment of compression equipment. The $5.0 million and $5.8 million impairment charge during the years ended December 31, 2017 and 2016, respectively, were primarily a result of our evaluation of the future deployment of our current idle fleet under the current market conditions. Our evaluation determined that due to certain performance characteristics of the impaired equipment, such as excessive maintenance costs and the inability of the equipment to meet then-current emission standards without retrofitting, this equipment was unlikely to be accepted by customers under then-current market conditions. As a result of our evaluation during the years ended December 31, 2017 and 2016, we determined to retire and either sell or re-utilize the key components of 40 and 29 compression units, with a total of approximately 11,000 and 15,000 horsepower, respectively, that had been previously used to provide compression services in our business.

Interest expense, net. The $4.0 million increase in interest expense, net was primarily attributable to the impact of an increase in our weighted average interest rate. Our revolving credit facility bore an interest rate of 3.46% and 2.94% at December 31, 2017 and 2016, respectively, and a weighted-average interest rate of 3.14% and 2.55% during the years ended December 31, 2017 and 2016, respectively. The impact of the increase in interest rate was partially offset by the impact of an $8.9 million decrease in average outstanding borrowings under our revolving credit facility. Average borrowings under the facility were $734.6 million for the year ended December 31, 2017 compared to $743.5 million for the year ended December 31, 2016.

Income tax expense. This line item represents the Revised Texas Franchise Tax (“Texas Margin Tax”) and change in deferred tax liability, which is materially consistent between both periods.

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Year ended December 31, 2016 compared to the year ended December 31, 2015

The following table summarizes our results of operations for the periods presented (dollars in thousands):

	Year Ended December 31,	Percent