USA Compression Partners, LP
Form 10-K
February 13, 2017
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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, 2016

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, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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

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, 2016, the last business day of the registrant's most recently completed second fiscal quarter was $291,788,017. This calculation does not reflect a determination that such persons are affiliates for any other purpose.

As of February 9, 2017, there were 60,689,110 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 acquired assets with our existing fleet;
- 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; and

- the effects of future litigation.

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. References to "Argonaut" refer to Argonaut Private Equity, L.L.C. and, where applicable, related entities.

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 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, 2016, we had 1,720,547 horsepower in our fleet and 20,000 horsepower on order for expected delivery during 2017. 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 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 installations, 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 and other artificial lift technologies are critical to the enhancement of production of oil from horizontal wells operating in tight shale plays. Gas lift is 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.

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

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reliable and flexible compression services in geographic areas of attractive growth helps us to generate stable cash flows for our unitholders.

We provide compression services to our customers under fixed-fee contracts with initial contract terms between six months and seven 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 United States. 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.

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. Following the decrease in oil prices throughout 2015 and into early 2016 and the subsequent increase since early 2016, the EIA estimates that oil production in 2016 was below levels in 2015. However, domestic crude oil production grew starting in late 2016, and the EIA now expects crude oil production in 2017 to increase over 2016 levels. As a result, the use of, and thus demand for, artificial lift techniques required in such production continues to be an attractive business for us. 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 fields.

- Continue to execute on attractive organic growth opportunities. From 2006 to 2016, we grew the horsepower in our fleet of compression units and our compression revenues at a compound annual growth rate of 16% and 18%, respectively, primarily through organic growth. We believe organic growth opportunities will continue to be our most attractive source of near-term growth and we expect such organic growth levels in 2017 will be similar to 2016 levels, which were lower than prior periods. 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.

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- 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. For example, in 2013 we completed the acquisition of assets and certain liabilities related to S&R Compression, LLC's ("S&R") business of providing gas lift compression services to third parties engaged in the exploration, production, gathering, processing, transportation or distribution of oil and gas (the "S&R Acquisition").

- 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.

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

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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, 2016 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 80.7% of our total fleet horsepower (including compression units on order) as of December 31, 2016. 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, 2016:

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	336,792	2,203	-	-	336,792	2,203	19.3 %	66.6 %
Large horsepower								
>400 and <1,000	162,987	286	-	-	162,987	286	9.4 %	8.6 %
>1,000	1,220,768	812	20,000	8	1,240,768	820	71.3 %	24.8 %
Total	1,720,547	3,301	20,000	8	1,740,547	3,309	100.0 %	100.0 %

(1) As of December 31, 2016, we had 20,000 horsepower on order for delivery during 2017.

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

	Year Ended December 31,	Percent Change

Operating Data:	2016	2015	2014	2016	2015
Fleet horsepower (at period end) (1)	1,720,547	1,712,196	1,549,020	0.5 %	10.5 %
Total available horsepower (at period end) (2)	1,730,547	1,712,196	1,623,400	1.1 %	5.5 %
Revenue generating horsepower (at period end) (3)	1,387,073	1,424,537	1,351,052	(2.6) %	5.4 %
Average revenue generating horsepower (4)	1,377,966	1,408,689	1,200,851	(2.2) %	17.3 %
Revenue generating compression units (at period end)	2,552	2,737	2,651	(6.8) %	3.2 %
Average horsepower per revenue generating compression unit (5)	534	517	505	3.3 %	2.4 %
Horsepower utilization (6):					
At period end	87.1 %	89.2 %	93.6 %	(2.4) %	(4.7) %
Average for the period (7)	87.4 %	90.5 %	94.0 %	(3.4) %	(3.7) %

(1) Fleet horsepower is horsepower for compression units that have been delivered to us (and excludes units on order). As of December 31, 2016, we had 20,000 horsepower on order for delivery during 2017.

(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 month-end revenue generating horsepower per revenue generating compression unit for each of the months in the period.

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(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 80.6%, 83.2% and 87.2% for the years ended December 31, 2016, 2015 and 2014, 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 80.3%, 85.1% and 87.3% for each year ended December 31, 2016, 2015, and 2014, 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 2017 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 runtimes, 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 seven 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, 2016, approximately 39% of our compression services on a horsepower basis (and 47% on a revenue basis for the year ended December 31, 2016) 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. 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

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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 43% and 45% of our revenue for the years ended December 31, 2016 and 2015, respectively.

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 Air Cooled Exchangers for coolers, and Ariel 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

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Corp. and 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, lead-times for such engines and frames are currently substantially 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 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

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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. In addition, the clear trend in environmental regulation is to place more restrictions on activities that may adversely affect the environment. 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. 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. In 2012, the EPA proposed amendments to the final rule in response to several petitions for reconsideration, which were finalized and became effective in 2013. The rule requires us to undertake certain expenditures and activities, including purchasing and installing emissions control equipment on certain compressor engines and generators.

In 2012, the EPA proposed minor amendments to the CAA regulations applicable to the manufacturers, owners and operators of new, modified and reconstructed stationary reciprocating internal combustion engines, also known as Quad J regulations, in order to conform the final rule to the amendments to the Quad Z regulations discussed above. These amendments were finalized and became effective in 2013.

In recent years, the EPA has lowered the National Ambient Air Quality Standard (“NAAQs”) for several air pollutants. For example, in 2013, the EPA lowered the annual standard for fine particulate matter, or PM 2.5 from 15 to 12 micrograms per cubic meter. In 2014, the EPA issued final area designations for the 2012 NAAQs for PM 2.5. In 2015, the EPA published the finalized rule strengthening the standards for ground level ozone. The final rule updates both the primary ozone standard and the secondary standard. Both standards 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. The EPA has taken a number of steps to amend or expand on these

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regulations since 2012. For example, in June 2016, the EPA 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 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.

In addition, in November 2016, the EPA issued an Information Collection Request seeking information about

methane emissions from facilities and operators in the oil and natural gas industry. The EPA has indicated that it intended to use the information from this request to develop Existing Source Performance Standards ("ESPS") for the oil and gas industry. Once adopted, the ESPS would not be imposed directly on regulated entities. Instead, they become guidelines that the states must consider in developing their own rules for regulating sources within their borders. The EPA has indicated that this information may also be used to develop standards for certain kinds of new and modified equipment and facilities not currently covered under Subpart OOOOa. 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.

A ruling by a panel of administrative law judges in a case before the Pennsylvania Environmental Hearing Board, to which we are not a party, may have implications for the permitting of projects where our customers seek to use our services. In this case, National Fuel Gas Midstream Corporation et al. v. Commonwealth of Pennsylvania, a panel of administrative law judges on December 29, 2015, dismissed an appeal of a determination by the Pennsylvania Department of Environmental Protection that the operations of two separate companies on parcels of land that were not adjoining and were actually separated by forest land but were in close proximity should be aggregated as a single source under the state air permitting regime. The implications of aggregating different sources into a single source is that the overall emissions increase and may increase enough to trigger a more onerous permitting regime and require more stringent controls. The court determined that this outcome was appropriate because, among other reasons, the two companies were owned by a common parent and had several interlocking officers and directors. But it was unclear whether the common parent in fact exercised control over the two companies' operations. Unless this ruling is overturned on further appeal, application of this ruling to other permit applications where the parties intend to use our services may lead to a permitting regime that is more burdensome, time-consuming and costly to our customers, who

typically obtain permits. Moreover, we may be required to install lower emission engines or additional pollution controls and may not be able to recoup all of the associated costs from our customers.

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

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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 is beginning 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 because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings by the EPA allowed the agency to proceed with the adoption and implementation of regulations that restrict emissions of greenhouse gases under existing provisions of the CAA. In 2009, the EPA adopted rules regarding regulation of greenhouse emissions from motor vehicles. Also in 2009, the EPA issued a final rule requiring the reporting of greenhouse gas emissions in the United States beginning in 2011 for emissions occurring in 2010 from specified large greenhouse gas emission sources. On November 30, 2010, the EPA published a final rule expanding its existing greenhouse gas emissions reporting rule for petroleum and natural gas facilities, including natural gas transmission compression facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year. The rule, which went into effect in 2010, requires reporting of greenhouse gas emissions by such regulated facilities to the EPA by September 2012 for emissions during 2011 and annually thereafter. In 2010, the EPA also issued a final rule, known as the "Tailoring Rule," that made certain large stationary sources and modification projects subject to permitting requirements for greenhouse gas emissions under the CAA.

Both the Tailoring Rule and the EPA's endangerment finding were challenged in federal court and were upheld by the D.C. Court of Appeals. In July 2014, the United States Supreme Court invalidated the Tailoring Rule but it refused to consider other issues such as whether greenhouse gases endanger public health. As a result, under federal law, a source is no longer required to meet the PSD and Title V permitting requirements based solely on its greenhouse gas emissions.

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 passed 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. It is not yet clear how either of the courts will ultimately rule on the legality of the Clean Power Plan. If the rule survives legal challenge, then depending on the methods used to implement this rule, it could reduce demand for the oil and natural gas our customers produce or increase the cost of electricity for our operations.

In addition to the EPA, the Bureau of Land Management ("BLM") has also promulgated rules to regulate hydraulic fracturing. The BLM rule establishes new requirements relating to well construction, water management, and chemical disclosure for companies drilling on federal and tribal land. In June 2016, the United States District Court for Wyoming set aside the rule, holding that the BLM lacked Congressional authority to promulgate the rule. The BLM has appealed the decision to the Tenth Circuit Court of Appeals. 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. State and industry groups have challenged this BLM rule in federal court, asserting that the BLM lacks authority to prescribe air quality regulations. It is not yet clear how either of the courts will ultimately rule on these challenges. In February 2017, the House passed a resolution disapproving the BLM Venting Rule pursuant to the Congressional Review Act. A similar resolution is currently under consideration by the Senate. If passed by the Senate and signed by President Trump, the rule will have no force or effect and cannot be replaced by a similar rule absent future legislation. If the BLM Venting Rule is

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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, the United States and nearly 200 other nations entered into an international climate agreement at the 2015 United Nations Framework Convention on Climate Change in Paris. Although this agreement does not create any binding obligations for nations to limit their greenhouse gas ("GHG") emissions, it does include pledges to voluntarily limit or reduce future emissions. The Paris Agreement entered into force in November 2016 and the United States is one of over 100 nations that have indicated an intent to comply with the 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 United States. 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 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 discharge permits that may be required under the CWA.

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 Safe Drinking

Water Act. 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

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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, 2016, USAC Management had 433 full time employees. None of our employees are subject to collective bargaining agreements. We consider our employee relations to be good.

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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 SEC. The information contained on our website does not constitute part of this report.

The Securities and Exchange Commission ("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 $32.3 million per quarter, or $129.1 million per year, based on the number of common units and the 1.3% general partner interest outstanding as of February 9, 2017. 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;
- 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

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· 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 in the locations where we operate 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 December 31, 2014, Henry Hub natural gas prices had decreased by 18% while WTI crude prices decreased by 42%; however the total rig count only decreased by 6% to 1,811 rigs. Over the course of the year ended December 31, 2015, commodity prices deteriorated further (natural gas prices and crude oil prices were 27% and 31% lower than at December 31, 2014, respectively). This continued decline in commodity prices had a more pronounced effect on drilling activity levels, as the total rig count decreased 61% to a total of 698 rigs over the same time period. This slowdown in new drilling activity caused some pressure on service rates for new and existing services and a decline in our utilization. Although commodity prices have increased during 2016, 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 recent 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 continue to experience further 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 43% and 45% of our revenue for the years ended December 31, 2016 and 2015, respectively. 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

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customers' spending for our services. For example, our customers could seek to preserve capital by using lower cost 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 seven 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, 2016, approximately 39% of our compression services on a horsepower basis (and 47% on a revenue basis for the year ended December 31, 2016) 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 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 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 in connection with other expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. There are no limitations in our partnership agreement on our ability to issue additional units, including units ranking senior to the common units. Similarly, the incurrence of borrowings or other debt by us to

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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, 2016, we had outstanding borrowings of $685.4 million with a leverage ratio of 4.7x, borrowing base availability (based on our borrowing base) of $414.6 million and, subject to compliance with the applicable financial covenants, available borrowing capacity under the revolving credit facility of $152.3 million. Financial covenants permit a maximum leverage ratio of (A) 5.75 to 1.0 as of the end of the fiscal quarter ending December 31, 2016, (B) 5.50 to 1.0 as of the end of the respective fiscal quarters ending March 31, 2017 and June 30, 2017, (C) 5.25 to 1.0 as of the end of the respective fiscal quarters ending September 30, 2017 and December 31, 2017 and (D) 5.00 to 1.0 thereafter. As of February 9, 2017, we had outstanding borrowings of $688.6 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").

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

We have recorded $35.9 million of goodwill and $75.2 million of other intangible assets as of December 31, 2016. 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 year ended December 31, 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.

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, 2016 and 2015, 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 29 and 166 compressor units, or approximately 15,000 and 58,000 horsepower, that were previously used to provide services in our business. As a result, we recognized impairments of approximately $5.8 million and $27.3 million during the years ended December 31, 2016 and 2015, respectively.

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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 Air Cooled Exchangers 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. 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 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

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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.

The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment over time. 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. In 2012, the EPA proposed amendments to the final rule in response to several petitions for reconsideration, which were finalized and became effective in 2013. The rule requires us to undertake certain expenditures and activities, including purchasing and installing emissions control equipment on certain compressor engines and generators. In 2012, the EPA proposed minor amendments to the CAA regulations applicable to the manufacturers, owners and operators of new, modified and reconstructed stationary reciprocating internal combustion engines, also known as Quad J regulations, in order to conform the final rule to the amendments to the Quad Z regulations discussed above. These amendments were finalized and became effective in 2013.

In recent years, the EPA has lowered the National Ambient Air Quality Standard (“NAAQS”) for several air pollutants. For example, in 2013, the EPA lowered the annual standard for fine particulate matter, or PM 2.5, from 15 to 12 micrograms per cubic meter. In 2014, the EPA issued final area designations for the 2012 NAAQs for PM 2.5. In 2015, the EPA published the finalized rule strengthening the standards for ground level ozone. The final rule updates both the primary ozone standard and the secondary standard. Both standards 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. The EPA has taken a number of steps to amend or expand on these regulations since 2012. For example, in June 2016, the EPA 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 stations. In addition, in November 2016, the EPA issued an Information Collection Request seeking information about methane emissions from facilities and operators in the oil and natural gas industry. The EPA has indicated that it intended to use the information from this request to develop Existing

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Source Performance Standards for the oil and gas industry. Once adopted, the ESPS would not be imposed directly on regulated entities. Instead, they become guidelines that the states must consider in developing their own rules for regulating sources within their borders. The EPA has indicated that this information may also be used to develop standards for certain kinds of new and modified equipment and facilities not currently covered under Subpart OOOOa. Subpart OOOOa and any additional regulation of air emissions from the oil and gas sector could 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.

A ruling by a panel of administrative law judges in a case before the Pennsylvania Environmental Hearing Board, to which we are not a party, may have implications for the permitting of projects where our customers seek to use our services. In this case, National Fuel Gas Midstream Corporation et al. v. Commonwealth of Pennsylvania, a panel of administrative law judges on December 29, 2015, dismissed an appeal of a determination by the Pennsylvania Department of Environmental Protection that the operations of two separate companies on parcels of land that were not adjoining and were actually separated by forest land but were in close proximity should be aggregated as a single source under the state air permitting regime. The implications of aggregating different sources into a single source is that the overall emissions increase and may increase enough to trigger a more onerous permitting regime and require more stringent controls. The court determined that this outcome was appropriate because, among other reasons, the two companies were owned by a common parent and had several interlocking officers and directors. But it was unclear whether the common parent in fact exercised control over the two companies' operations. Unless this ruling is overturned on further appeal, application of this ruling to other permit applications where the parties intend to use our services may lead to a permitting regime that is more burdensome, time-consuming and costly to our customers, who typically obtain permits. Moreover, we may be required to install lower emission engines or additional pollution controls and may not be able to recoup all of the associated costs from our customers.

There can be no assurance that future requirement 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 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, the EPA is beginning 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 because emissions of such gases are,

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according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings by the EPA allowed the agency to proceed with the adoption and implementation of regulations that restrict emissions of greenhouse gases under existing provisions of the CAA. In 2009, the EPA adopted rules regarding regulation of greenhouse emissions from motor vehicles. Also in 2009, the EPA issued a final rule requiring the reporting of greenhouse gas emissions in the United States beginning in 2011 for emissions occurring in 2010 from specified large greenhouse gas emission sources. On November 2010, the EPA published a final rule expanding its existing greenhouse gas emissions reporting rule for petroleum and natural gas facilities, including natural gas transmission compression facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year. The rule, which went into effect in 2010, requires reporting of greenhouse gas emissions by such regulated facilities to the EPA by September 2012 for emissions during 2011 and annually thereafter. In 2010, the EPA also issued a final rule, known as the "Tailoring Rule," that made certain large stationary sources and modification projects subject to permitting requirements for greenhouse gas emissions under the CAA.

Both the Tailoring Rule and the EPA's endangerment finding were challenged in federal court and were upheld by the D.C. Court of Appeals. In July 2014, the United States Supreme Court invalidated the Tailoring Rule but it refused to consider other issues such as whether greenhouse gases endanger public health. As a result, under federal law, a source is no longer required to meet the PSD and Title V permitting requirements based solely on its greenhouse gas emissions.

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 passed 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. It is not yet clear how either of the courts will ultimately rule on the legality of the Clean Power Plan. If this rule survives legal challenge, then depending on the methods used to implement this rule, it could reduce demand for the oil and natural gas our customers produce or increase the cost of electricity for our operations.

In addition to the EPA, the Bureau of Land Management ("BLM") also promulgated rules to regulate hydraulic fracturing. The BLM rule establishes new requirements relating to well construction, water management, and chemical disclosure for companies drilling on federal and tribal land. In June 2016, the United States District Court for Wyoming set aside the rule, holding that the BLM lacked Congressional authority to promulgate the rule. The BLM has appealed the decision to the Tenth Circuit Court of Appeals. 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. 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. State and industry groups have challenged this BLM rule in federal court, asserting that the BLM lacks authority to prescribe air quality regulations. It is not yet clear how either of the courts will ultimately rule on these challenges. In

February 2017, the House passed a resolution disapproving the BLM Venting Rule pursuant to the Congressional Review Act. A similar resolution is currently under consideration by the Senate. If passed by the Senate and signed by President Trump, the rule will have no force or effect and cannot be replaced by a similar rule absent future legislation. 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, the United States and nearly 200 other nations entered into an international climate agreement at the 2015 United Nations Framework Convention on Climate Change in Paris. Although this agreement does not create any binding obligations for nations to limit their GHG emissions, it does include pledges to voluntarily limit or reduce future emissions. The Paris Agreement entered into force in November 2016 and the United States is one of over 100 nations that have indicated an intent to comply with the agreement.

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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.

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 Safe Drinking Water Act. 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. 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.

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 may be for up to five fiscal years after the date we completed our initial public offering, which was in January 2013. 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.

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USA Compression Holdings owns and controls our general partner, which has sole responsibility for conducting our business and managing our operations. Our general partner and its affiliates, including USA Compression Holdings, 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 owners. Conflicts of interest will arise between USA Compression Holdings, Riverstone and our general partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of USA Compression Holdings and the other owners of USA Compression Holdings 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 USA Compression Holdings 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 USA Compression Holdings, 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;

- 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

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units is required to remove our general partner. USA Compression Holdings owns an aggregate of 39% 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 1.3%) 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.

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.

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 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.

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We may issue additional units without your approval, 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 unitholders. The issuance by us of additional common units, including pursuant to our Distribution Reinvestment Plan ("DRIP") or our continuous offering program, 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; and
- assuming the distribution per unit remains unchanged or increases, the cash distributions to the holder of the IDRs will increase.

USA Compression Holdings and Argonaut 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, 2016, USA Compression Holdings holds an aggregate of 23,929,263 common units. 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. We have agreed to provide USA Compression Holdings and Argonaut 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 39% of our outstanding common units.

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.

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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. Substituted limited partners are liable both for the obligations of the assignor to make contributions to the partnership that were known to the substituted limited partner at the time it became a limited partner and for those obligations that were unknown if the liabilities could have been determined from the partnership agreement. Neither liabilities to partners on account of their partnership interest nor liabilities that are non-recourse to the partnership are counted for purposes of determining whether a distribution is permitted.

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 could be an emerging growth company until the end of the fiscal year in which the five year anniversary of our initial public offering occurred, which was January 18, 2013. 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.

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, which is currently a maximum of 35%, and would likely pay state and local income tax at varying rates. Distributions would generally be taxed again as corporate dividends (to the extent of our current and

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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.

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 such changes could negatively impact the value of an 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.

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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. Recently enacted legislation alters the procedures for assessing and collecting taxes due for taxable years beginning after December 31, 2017, in a manner that could substantially reduce cash available for distribution to you.

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.

Recently enacted legislation applicable to us for taxable years beginning after December 31, 2017 alters the procedures for auditing large partnerships and also alters the procedures for assessing and collecting taxes due (including applicable penalties and interest) as a result of an audit. Unless we are eligible to (and choose to) elect to issue revised Schedules K-1 to our partners with respect to an audited and adjusted return, the IRS may assess and collect taxes (including any applicable penalties and interest) directly from us in the year in which the audit is completed under the new rules. If we are required to pay taxes, penalties and interest as the result of audit adjustments, cash available for distribution to our unitholders may be substantially reduced. In addition, because payment would be due for the taxable year in which the audit is completed, unitholders during that taxable year would bear the expense of the adjustment even if they were not unitholders during the audited taxable year.

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. Furthermore, a substantial portion of the amount realized on any sale of common units, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder's share of our nonrecourse liabilities, a unitholder that sells common units may incur a tax liability in excess of the amount of cash received from the sale.

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

Investment in common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts ("IRAs"), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be subject to withholding taxes imposed at the highest tax rate applicable to such non-U.S. persons, and each non-U.S. person will be required to file federal income tax returns and pay tax on its share of our taxable income. If you are a tax-exempt entity or a non-U.S. person, you should consult a tax advisor before investing in our common units.

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

Because we cannot match transferors and transferees of common units and because of other reasons, we will adopt depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to you. It also

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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 effect a short sale of common units) may be considered as having disposed of those common units. If so, he would no longer be treated for federal income tax purposes as a partner with respect to those common units during the period of the loan and may recognize gain or loss from the disposition.

Because 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 loaning their common units.

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

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

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

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have technically terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once. Our technical termination would,

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among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1 if relief was not available, as described below) for one calendar year and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a calendar year, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. A technical termination currently would not affect our classification as a partnership for federal income tax purposes, but instead we would be treated as a new partnership for such tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred. The IRS has announced a publicly traded partnership technical termination relief program whereby a publicly traded partnership that technically terminated may request publicly traded partnership technical termination relief which, if granted by the IRS, among other things would permit the partnership to provide only one Schedule K-1 to unitholders for the year notwithstanding two partnership tax years.

As a result of investing in our common units, you will likely become subject to state and local taxes and return filing requirements in jurisdictions where we operate or own or acquire properties.

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or control property now or in the future, even if 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 those 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.

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, 2016, our headquarters consisted of 18,167 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.

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 9, 2017, we had outstanding 60,689,110 common units, a 1.3% general partner interest (“General Partner Interest”) and the IDRs. The number of common units outstanding on this date includes 14,048,588 common units that converted from subordinated units on February 16, 2016. USA Compression Holdings owns a 100%

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membership interest in our general partner. As of February 9, 2017, USA Compression Holdings owned approximately 39% 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 9, 2017, was $18.52.

	Price Range		Cash Distribution Declared Per Common	
Period	High	Low	Unit	Date Paid
First Quarter 2015	$ 21.60	$ 15.57	$ 0.515	May 15, 2015
Second Quarter 2015	$ 24.30	$ 18.33	$ 0.525	August 14, 2015
Third Quarter 2015	$ 20.95	$ 13.26	$ 0.525	November 13, 2015
Fourth Quarter 2015	$ 18.89	$ 10.19	$ 0.525	February 12, 2016
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

Holders

At the close of business on February 9, 2017, based on information received from the transfer agent of the common units, we had 60 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 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

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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.

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").

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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, 2016, 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 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 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.

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	Year Ended December 31,				
	2016	2015	2014	2013	2012
	(in thousands, except for unit amounts)				
Revenues:					
Contract operations	$ 246,950	$ 263,816	$ 217,361	$ 150,360	$ 116,373
Parts and service	18,971	6,729	4,148	2,558	2,414
Total revenues	265,921	270,545	221,509	152,918	118,787
Costs of operations, exclusive of depreciation and amortization:					
Cost of operations	88,161	81,539	74,035	48,097	37,796
Gross operating margin (1)	177,760	189,006	147,474	104,821	80,991
Other operating and administrative costs and expenses:					
Selling, general and administrative	44,483	40,950	38,718	27,587	18,269
Depreciation and amortization	92,337	85,238	71,156	52,917	41,880
Loss (gain) of sale of assets	772	(1,040)	(2,233)	284	266
Impairment of compression equipment	5,760	27,274	2,266	203	—
Impairment of goodwill	—	172,189	—	—	—
Total other operating and administrative costs and expenses	143,352	324,611	109,907	80,991	60,415
Operating income (loss)	34,408	(135,605)	37,567	23,830	20,576
Other income (expense):					
Interest expense, net	(21,087)	(17,605)	(12,529)	(12,488)	(15,905)
Other	35	22	11	9	28
Total other expense	(21,052)	(17,583)	(12,518)	(12,479)	(15,877)
Income (loss) before income tax expense	13,356	(153,188)	25,049	11,351	4,699
Income tax expense	421	1,085	103	280	196
Net income (loss)	12,935	(154,273)	24,946	11,071	4,503
Adjusted EBITDA (1)	$ 146,648	$ 153,572	$ 114,409	$ 81,130	$ 63,484
DCF (1)	$ 118,329	$ 120,850	$ 85,927	$ 56,210	$ 34,928
Basic and diluted net income (loss) per common unit:	$ 0.27	$ (3.15)	$ 0.60	$ 0.32	$ —
Cash distributions declared per common unit	$ 2.10	$ 2.09	$ 2.01	$ 1.73	$ —
Other Financial Data:					
Capital expenditures (2)	$ 48,665	$ 265,798	$ 404,429	$ 175,393	$ 185,917
Cash flows provided by (used in):					
Operating activities	$ 103,697	$ 117,401	$ 101,891	$ 68,190	$ 41,974
Investing activities	$ (50,831)	$ (278,158)	$ (380,523)	$ (153,946)	$ (178,589)
Financing activities	$ (52,808)	$ 160,758	$ 278,631	$ 85,756	$ 136,618
Balance Sheet Data (at period end):					
Working capital (3)	$ 16,558	$ (8,455)	$ (44,064)	$ (24,177)	$ (12,076)
Total assets	$ 1,472,412	$ 1,509,771	$ 1,516,482	$ 1,185,884	$ 872,645
Long-term debt	$ 685,371	$ 729,187	$ 594,864	$ 420,933	$ 502,266

Partners' equity	$ 729,517	$ 718,288	$ 839,520	$ 707,727	$ 343,526

(1) Please refer to "—Non-GAAP Financial Measures" section below.
(2) The Partnership applied an $8.0 million credit received from a supplier during 2011 to new compression unit purchases from this supplier in the year ended December 31, 2012. Before the application of this credit, capital expenditures were $193.9 million for the year ended December 31, 2012.
(3) 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 taxes. 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, loss (gain) on sale of assets and other, and certain transaction expenses. 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 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

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consider both net income (loss) and net cash provided by operating activities determined under GAAP, as well as 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,				
	2016	2015	2014	2013	2012
Net income (loss)	$ 12,935	$ (154,273)	$ 24,946	$ 11,071	$ 4,503
Interest expense, net	21,087	17,605	12,529	12,488	15,905
Depreciation and amortization	92,337	85,238	71,156	52,917	41,880
Income tax expense	421	1,085	103	280	196
EBITDA	$ 126,780	$ (50,345)	$ 108,734	$ 76,756	$ 62,484
Impairment of compression equipment (1)	5,760	27,274	2,266	203	—
Impairment of goodwill (2)	—	172,189	—	—	—
Interest income on capital lease	1,492	1,631	1,274	—	—
Unit-based compensation expense (3)	10,373	3,863	3,034	1,343	—
Riverstone management fee (4)	—	—	—	49	1,000
Transaction expenses for acquisitions (5)	894	—	1,299	2,142	—
Severance charges	577	—	—	—	—
Loss (gain) on sale of assets and other	772	(1,040)	(2,198)	637	—
Adjusted EBITDA	$ 146,648	$ 153,572	$ 114,409	$ 81,130	$ 63,484
Interest expense, net	(21,087)	(17,605)	(12,529)	(12,488)	(15,905)
Income tax expense	(421)	(1,085)	(103)	(280)	(196)
Interest income on capital lease	(1,492)	(1,631)	(1,274)	—	—
Non-cash interest expense and other	2,108	1,702	1,189	1,839	(58)
Riverstone management fee	—	—	—	(49)	(1,000)
Transaction expenses for acquisitions	(894)	—	(1,299)	(2,142)	—
Severance charges	(577)	—	—	—	—
Changes in operating assets and liabilities	(20,588)	(17,552)	1,498	180	(4,351)
Net cash provided by operating activities	$ 103,697	$ 117,401	$ 101,891	$ 68,190	$ 41,974

(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, 2016, 2015, 2014 and 2013, unit-based compensation expense included $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 $0.1 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 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 and 2012. 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. The Partnership believes 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, proceeds from insurance recovery and (gain) loss on sale of equipment, 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 sale 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,				
	2016	2015	2014	2013	2012
Net income (loss)	$ 12,935	$ (154,273)	$ 24,946	$ 11,071	$ 4,503
Plus: Non-cash interest expense	2,108	1,702	1,224	2,201	1,855
Plus: Non-cash income tax expense	239	874	—	—	—
Plus: Depreciation and amortization	92,337	85,238	71,156	52,917	41,880
Plus: Unit-based compensation expense (1)	10,373	3,863	3,034	1,343	—
Plus: Impairment of compression equipment	5,760	27,274	2,266	203	—
Plus: Impairment of goodwill	—	172,189	—	—	—
Plus: Transaction expenses for acquisitions (2)	894	—	1,299	2,142	—
Plus: Severance charges	577	—	—	—	—
Plus: Loss (gain) on sale of assets and other	772	(1,040)	(2,198)	637	—
Plus: Proceeds from insurance recovery	73	1,157	—	—	—
Less: Maintenance capital expenditures (3)	(7,739)	(16,134)	(15,800)	(14,304)	(13,310)
DCF	$ 118,329	$ 120,850	$ 85,927	$ 56,210	$ 34,928
Plus: Maintenance capital expenditures	7,739	16,134	15,800	14,304	13,310
Plus: Net gain on change in fair value of interest rate swap	—	—	—	—	(2,180)
Plus: Change in working capital	(20,588)	(17,552)	1,498	180	(4,351)
Less: Transaction expenses for acquisitions	(894)	—	(1,299)	(2,142)	—
Less: Other	(889)	(2,031)	(35)	(362)	267
Net cash provided by operating activities	$ 103,697	$ 117,401	$ 101,891	$ 68,190	$ 41,974

(1) For the years ended December 31, 2016, 2015, 2014 and 2013, unit-based compensation expense includes $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 $0.1 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 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. The Partnership believes 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 the Partnership's general partner and IDRs, divided by distributions declared to limited partner unitholders for the period. Cash Coverage Ratio is defined as DCF less cash distributions to the Partnership's general partner and IDRs divided by cash distributions paid to limited partner unitholders, 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,			
	2016	2015	2014	2013
DCF	$ 118,329	$ 120,850	$ 85,927	$ 56,210
General partner interest in DCF	2,866	2,658	1,947	1,188
Pre-IPO DCF	—	—	—	2,323
DCF attributable to limited partner interest	$ 115,463	$ 118,192	$ 83,980	$ 52,699
Distributions for DCF coverage ratio (1)	$ 115,881	$ 101,266	$ 85,098	$ 55,961
Distributions reinvested in the DRIP (2)	24,441	55,489	52,556	36,694
Distributions for Cash Coverage Ratio (3)	$ 91,440	$ 45,777	$ 32,542	$ 19,267
DCF Coverage Ratio (4)	1.00	1.17	0.99	0.94
Cash Coverage Ratio (5)	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 the 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 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 units outstanding at 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 units outstanding at 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 comparably 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 installations, 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

Following the decline and general volatility in crude oil and natural gas prices from late 2014 until early 2016, commodity prices in early 2016 increased overall due to a variety of factors, including production declines, reduced drilling activity and continued increases in overall demand, both domestically and globally. While our business does not have direct exposure to commodity prices, the general activity levels of our customers can be affected by commodity prices. The depressed price environment in 2014, 2015 and 2016 resulted in a slowdown in activity in many domestic producing regions, particularly in those plays where producers targeted oil or other liquids and natural

gas plays with relatively higher production costs. That decreased level of operating activity led, in part, to reduced demand for compression services during 2015 and 2016. With the relative increase in, and stabilization of, commodity prices during the second-half of 2016, we believe our customers have increased, and intend to continue to increase, general activity levels with regards to exploration and production activities and the build-out of midstream infrastructure, particularly in areas with favorable economics. In addition to existing production continuing to require compression, we expect our customers' new activity will lead to increased demand for compression services in the second half of 2017.

A significant amount of our assets are utilized in natural gas infrastructure applications, primarily in centralized 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. While the slowdown in new drilling activity in certain operating areas over the last few years, as well as slowing or flattening of production growth in other areas, resulted in pressure on service rates for new and existing services and a corresponding decline in utilization, the continued midstream infrastructure build-out and recent stabilization in commodity prices has lessened the pressure on service rates, in particular with regards to large horsepower compression units, a category in which we believe the current industry inventory is relatively limited. 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. While the recent increase in the price of crude oil has given rise to increased drilling activity, service rates for small horsepower units have not yet

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meaningfully increased back to levels experienced prior to the downturn in crude oil prices due to the large industry inventory of such units and we believe such depressed service rates could continue through 2017.

We continue to monitor developments in our customer base, and we believe that there will continue to be demand for our services given the necessity of compression services in allowing for the transportation and processing of natural gas as well as the production of crude oil, although management cannot predict any possible changes in such demand with reasonable certainty. The increase in commodity prices during 2016 has caused many of our customers to announce increased capital budgets for 2017 compared to 2016, which is expected to result in additional large-scale natural gas infrastructure and crude oil production activities. In conjunction with what we believe will be increased demand for our compression services, we intend to prudently deploy capital for new units in 2017 as well as place significant focus on increasing the utilization of our existing fleet of infrastructure-oriented equipment by redeploying currently idle units. We expect to spend this relatively minimal amount of capital on large horsepower units for specific infrastructure applications, which tend to generate higher margins and command longer contract terms. In the event customer demand significantly exceeds the horsepower capacity we have in idle units and on order, we may make additional capital expenditures above currently anticipated levels to satisfy this increased customer demand.

Our ability to increase our revenues is dependent in large part on our ability to add new revenue generating compression units to our fleet while maintaining our utilization and contract rates. For the year ended December 31, 2016, we increased our fleet horsepower as a result of delivery of certain new units. Utilization decreased moderately, as we focused on pursuing more economical business opportunities. Revenue generating horsepower decreased 2.6% from December 31, 2015 to December 31, 2016. Average revenue generating horsepower decreased 2.2% from the year ended December 31, 2015 to the year ended December 31, 2016. Average revenue per revenue generating horsepower per month decreased approximately 3.1% from the year ended December 31, 2015 to the year ended December 31, 2016. Average utilization decreased approximately 3.4% from the year ended December 31, 2015 to the year ended December 31, 2016. The decrease in utilization was attributable to both an increase in the amount of time contracting new compression units and an increase in the amount of compression units returned to us. We believe this is the result of a delay in planned projects of certain of our customers and continued optimization of existing compression service requirements.

The EIA has projected that natural gas production growth will continue in the coming years due to increases in drilling efficiencies as well as a backlog of drilled but uncompleted wells in major supply areas, such as the Marcellus Shale. Additionally, according to the EIA, domestic exports, both to Mexico and through the start-up of various liquefied natural gas (“LNG”) projects in late 2015 and beyond, will increase and this increased demand should keep pace with increasing supply growth. The EIA projects that approximately 70% of the increase in natural gas production through 2040 will come from shale plays, which typically require greater compression horsepower than conventional production. We believe this long-term increasing demand for natural gas will create increasing demand for compression services, for both existing natural gas fields as they age and for the development of new natural gas fields. In the short-term, changes in natural gas pricing, based primarily upon the supply of natural gas, will affect the development activities of natural gas producers based upon the costs associated with finding and producing natural gas in the particular natural gas and oil fields in which they are active.

The EIA estimates that while domestic crude production decreased in 2016 versus 2015, it is expected to increase slightly in 2017 from 2016 levels. The increase in the price of crude oil during the course of 2016 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, we expect the increase in demand for gas lift compression in these new areas of drilling will be delayed until reservoir pressures decline to a point where compression is beneficial to the economics of a particular well or basin. We then expect that a general decrease in crude oil production will ultimately increase the demand for our smaller horsepower units engaged in gas lift applications in the long-term. In addition to these new areas of drilling, we believe that our flexible fleet of smaller horsepower units that are primarily utilized in gas lift applications can immediately satisfy the market demand for continued incremental production in fields with declining production.

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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:	2016	2015	2014	2016	2015
Fleet horsepower (at period end) (1)	1,720,547	1,712,196	1,549,020	0.5 %	10.5 %
Total available horsepower (at period end) (2)	1,730,547	1,712,196	1,623,400	1.1 %	5.5 %
Revenue generating horsepower (at period end) (3)	1,387,073	1,424,537	1,351,052	(2.6) %	5.4 %
Average revenue generating horsepower (4)	1,377,966	1,408,689	1,200,851	(2.2) %	17.3 %
Average revenue per revenue generating horsepower per month (5)	$ 15.41	$ 15.90	$ 15.57	(3.1) %	2.1 %
Revenue generating compression units (at period end)	2,552	2,737	2,651	(6.8) %	3.2 %
Average horsepower per revenue generating compression unit (6)	534	517	505	3.3 %	2.4 %
Horsepower utilization (7):					
At period end	87.1 %	89.2 %	93.6 %	(2.4) %	(4.7) %
Average for the period (8)	87.4 %	90.5 %	94.0 %	(3.4) %	(3.7) %

(1) Fleet horsepower is horsepower for compression units that have been delivered to us (and excludes units on order). As of December 31, 2016, we had 20,000 horsepower on order for delivery during 2017.

(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 at each applicable period end was 80.6%, 83.2% and 87.2%, for the years ended December 31, 2016, 2015 and 2014, 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 was 80.3%, 85.1% and

87.3% for each year ended December 31, 2016, 2015 and 2014, respectively.

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 our large

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horsepower compression units which typically generate lower average revenue per revenue generating horsepower than do small horsepower compression units.

The 10.5% increase in fleet horsepower as of December 31, 2015 over the fleet horsepower as of December 31, 2014 was attributable to new compression units added to our fleet to meet anticipated demand by new and current customers. The 5.4% increase in revenue generating horsepower as of December 31, 2015 over December 31, 2014 was primarily due to organic growth in our active fleet. The 2.4% increase in average horsepower per revenue generating compression unit as of December 31, 2015 over December 31, 2014 was primarily due to the addition of large horsepower compression units in the operating fleet over the year ended December 31, 2015.

Average horsepower utilization decreased approximately 3.4% during the year ended December 31, 2016 compared to the year ended December 31, 2015. The 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 decreased approximately 3.7% during the year ended December 31, 2015 compared to the year ended December 31, 2014. The decrease in average horsepower utilization was primarily attributable to the following changes as a percentage of total available horsepower: (1) a 1.2% increase in our average fleet of compression units returned to us not yet under contract and (2) a 5.2% decrease in horsepower that is on-contract or pending-contract but not yet active. 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 deem to be the most attractive opportunities. The above noted fluctuation in utilization components also describes the changes in period end horsepower utilization between the comparable periods.

Average horsepower utilization based on revenue generating horsepower and fleet horsepower decreased approximately 5.6% during the year ended December 31, 2016 compared to the year ended December 31, 2015. The 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 factors also describe the variance 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.

Average horsepower utilization based on revenue generating horsepower and fleet horsepower decreased approximately 2.5% during the year ended December 31, 2015 compared to the year ended December 31, 2014. The decrease is primarily attributable to the following changes as a percentage of total fleet horsepower: (1) a 1.1% increase in our average idle fleet from compression units returned to us and (2) a 1.3% increase in our average idle fleet composed of new compression units. The increase in new units not yet under contract was due to the growth in our fleet during the year and the increase in units returned to us is believed to be a result of our customers' optimization of their compression service requirements. These factors also describe the variance in period end horsepower utilization based on revenue generating horsepower and fleet horsepower between the year ended December 31, 2015 and the year ended December 31, 2014.

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Financial Results of Operations

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 Change
	2016	2015	
Revenues:			
Contract operations	$ 246,950	$ 263,816	(6.4) %
Parts and service	18,971	6,729	181.9 %
Total revenues	265,921	270,545	(1.7) %
Costs and expenses:			
Cost of operations, exclusive of depreciation and amortization	88,161	81,539	8.1 %
Gross operating margin	177,760	189,006	(6.0) %
Other operating and administrative costs and expenses:			
Selling, general and administrative	44,483	40,950	8.6 %
Depreciation and amortization	92,337	85,238	8.3 %
Loss (gain) on sale of assets	772	(1,040)	174.2 %
Impairment of compression equipment	5,760	27,274	(78.9) %
Impairment of goodwill	—	172,189	*
Total other operating and administrative costs and expenses	143,352	324,611	(55.8) %
Operating income (loss)	34,408	(135,605)	125.4 %
Other income (expense):			
Interest expense, net	(21,087)	(17,605)	19.8 %
Other	35	22	59.1 %
Total other expense	(21,052)	(17,583)	19.7 %
Income (loss) before income tax expense	13,356	(153,188)	108.7 %
Income tax expense	421	1,085	(61.2) %
Net income (loss)	$ 12,935	$ (154,273)	108.4 %

* Not meaningful.

Contract operations revenue. During 2016, we experienced a year-to-year decrease in demand for our compression services driven by decreased operating activity in natural gas and crude oil production and continued optimization of existing compression service requirements, resulting in a 2.2% decrease in average revenue generating horsepower

and a $16.9 million decrease in our contract operations revenue. Average revenue per revenue generating horsepower per month decreased from $15.90 for the year ended December 31, 2015 to $15.41 for the year ended December 31, 2016, a decrease of 3.1%, 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 3.3% increase in the average horsepower per revenue generating compression unit in the current period, as large horsepower compression units generally 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 was somewhat higher than the average revenue per revenue generating horsepower per month associated with our compression services provided under contracts in the primary term due to pressure on service rates attributable to the small horsepower portion of our fleet. Because the demand for our services is driven primarily by production of natural gas, we focus our activities in areas of attractive growth, which are generally found in certain shale and unconventional resource plays, as discussed above under the heading “Overview.” 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. During 2016, we recognized $15.7 million of revenue associated with installation services, which accounts for the $12.2 million year-over-year increase in parts and service revenue. The remaining component of

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our parts and service revenue, which was earned primarily on (1) freight and crane charges that are directly reimbursed by our customers, for which we earn little to no margin, and (2) maintenance work on units at our customers' locations that are outside the scope of our core maintenance activities, for which we earn lower margins than our contract operations, decreased $3.5 million during the current period.

Cost of operations, exclusive of depreciation and amortization. The $6.6 million increase in cost of operations was primarily attributable to an $8.3 million increase in retail parts and service expenses, which includes $11.9 million of additional costs associated with our installation services. Excluding these costs, retail parts and services expense decreased $3.6 million reflecting a corresponding decrease in this component of parts and services revenue. Additionally during the period, we experienced (1) a $2.1 million decrease in direct expenses, such as parts and fluids expenses, (2) a $0.6 million decrease in direct labor expenses and (3) a $0.5 million decrease in expenses related to our vehicle fleet, offset by (4) a $1.7 million increase in property and other taxes. The decrease in direct parts, fluids, labor and vehicle expenses are primarily driven by the decrease in average revenue generating horsepower during the current period.

Gross operating margin. The $11.2 million decrease in gross operating margin was primarily due to a decrease in revenues, partially offset by a decrease in operating expenses and the $3.8 million of gross operating margin we earned from our installation services during the year ended December 31, 2016.

Selling, general and administrative expense. The $3.5 million increase in selling, general and administrative expense for the year ended December 31, 2016 was primarily attributable to a $6.5 million increase in unit-based compensation expense, partially offset by a $2.9 million decrease in bad debt expense. Unit-based compensation expense increased primarily due to (1) the increase in our unit price as of December 31, 2016 compared to December 31, 2015, (2) a greater number of outstanding phantom units as of December 31, 2016 compared to December 31, 2015 which resulted from a higher number of phantom unit grants during 2016 as compared to 2015 (reflecting our sharply lower unit price at the time the grants were made in 2016 versus our unit price at the time the grants were made in 2015), and (3) a greater number of phantom units outstanding on which distribution equivalent rights were paid as of each record date during the comparable periods. The decrease in bad debt expense was due primarily to a $1.1 million decrease in allowance for doubtful accounts during the year ended December 31, 2016 due in part to collections on accounts that had previously been reserved during the year ended December 31, 2015 as compared to a $1.8 million increase in the allowance for doubtful accounts during the year ended December 31, 2015.

Depreciation and amortization expense. The $7.1 million increase in depreciation expense was related to an increase in gross property and equipment balances during the year ended December 31, 2016 compared to gross balances during the year ended December 31, 2015. There is no variance in amortization expense between the periods, as intangible assets are amortized on a straight-line basis and there has been no change in gross identifiable intangible assets between the periods.

(Gain) on sale of assets. During the year ended December 31, 2016, we abandoned certain assets and incurred a $1.0 million loss. The $1.0 million gain on sale of assets during the year ended December 31, 2015 was primarily attributable to $1.2 million cash insurance recoveries on previously impaired compression equipment received during the year and $1.1 million gain on sale of 18 units, or 7,200 horsepower, offset by $1.3 million of losses incurred in the disposal of various unit and non-unit assets.

Impairment of compression equipment. The $5.8 million and $27.3 million impairment charge during the years ended December 31, 2016 and 2015, 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 current emission standards without retrofitting, this equipment was unlikely to be accepted by customers under current market conditions. As a result of our evaluation during the years ended December 31, 2016 and 2015, we determined to retire and either sell or re-utilize the key components of 29 and 166 compression units, with a total of approximately 15,000 and 58,000 horsepower, respectively, that had been previously used to provide compression services in our business.

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Goodwill impairment. There was no impairment of goodwill for the year ended December 31, 2016. During the year ended December 31, 2015, we recorded 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.

Interest expense, net. The $3.5 million increase in interest expense, net was primarily attributable to the impact of an approximately $20.2 million increase in average outstanding borrowings under our revolving credit facility, in which average borrowings were $743.5 million for the year ended December 31, 2016 compared to $723.3 million for the year ended December 31, 2015. Our revolving credit facility had an interest rate of 2.94% and 2.26% at December 31, 2016 and 2015, respectively, and a weighted-average interest rate of 2.55% and 2.24% during the years ended December 31, 2016 and 2015, respectively.

Income tax expense. This line item represents the Revised Texas Franchise Tax (“Texas Margin Tax”). The decrease in income tax expense for the year ended December 31, 2016 compared to December 31, 2015 was primarily associated with the establishment of a deferred tax liability reflecting the book/tax basis difference in our property and equipment during the year ended December 31, 2015.

Year ended December 31, 2015 compared to the year ended December 31, 2014

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

	Year Ended December 31,		Percent Change
	2015	2014	
Revenues:			
Contract operations	$ 263,816	$ 217,361	21.4 %
Parts and service	6,729	4,148	62.2 %
Total revenues	270,545	221,509	22.1 %
Costs and expenses:			
Cost of operations, exclusive of depreciation and amortization	81,539	74,035	10.1 %
Gross operating margin	189,006	147,474	
Other operating and administrative costs and expenses:			
Selling, general and administrative	40,950	38,718	5.8 %
Depreciation and amortization	85,238	71,156	19.8 %
Loss (gain) on sale of assets	(1,040)	(2,233)	53.4 %
Impairment of compression equipment	27,274	2,266	1,103.6 %

Impairment of goodwill	172,189	—	*	%
Total other operating and administrative costs and expenses	324,611	109,907	195.4	%
Operating income	(135,605)	37,567	(461.0)	%
Other income (expense):				
Interest expense	(17,605)	(12,529)	40.5	%
Other	22	11	100.0	%
Total other expense	(17,583)	(12,518)	40.5	%
Income before income tax expense	(153,188)	25,049	(711.6)	%
Income tax expense	1,085	103	953.4	%
Net income	$ (154,273)	$ 24,946	(718.4)	%

* Not meaningful.

Contract operations revenue. During 2015, we experienced an increase in demand for our compression services driven by an increase in overall natural gas production in the U.S., resulting in a 17.3% increase in average revenue generating horsepower and a $46.5 million increase in our contract operations revenue. Average revenue per revenue generating horsepower per month increased from $15.57 for the year ended December 31, 2014 to $15.90 for the year ended December 31, 2015, an increase of 2.1%, attributable, in part, to growth in the small horsepower fleet, which earns higher revenue per horsepower, in addition to improved pricing in the large horsepower fleet. Average revenue per

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revenue generating horsepower per month associated with our compression services provided on a month-to-month basis did not significantly differ from the revenue per revenue generating horsepower per month associated with our compression services provided under contracts in the primary term. Because the demand for our services is driven primarily by production of natural gas, we focus our activities in areas of attractive growth, which are generally found in certain shale and unconventional resource plays, as discussed above under the heading “Overview.” 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 freight and crane charges that are directly reimbursable by our customers, for which we earn little to no margin, and maintenance work on units at our customers’ locations that are outside the scope of our core maintenance activities, for which we earn lower margins than our contract operations. We offered these 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 $7.5 million increase in cost of operations was primarily attributable to the increase in our active fleet size due to organic growth. Certain cost increases consisted of (1) a $3.9 million increase in direct labor expenses, (2) a $3.1 million increase in direct expenses such as parts and service expenses, which have a corresponding increase in parts and service revenue, and (3) a $1.9 million increase in indirect expenses, the majority of which were higher property taxes, offset by a $1.1 million decrease in fuel costs.

Gross operating margin. The $41.5 million increase in gross operating margin was due to higher revenues partially offset by higher operating expenses during the year ended December 31, 2015. The 3.3% increase in gross operating margin percentage from 66.6% for the year ended December 31, 2014 to 69.9% for the year ended December 31, 2015 was attributable to (1) certain cost savings initiatives, (2) timing of certain preventative maintenance activities and (3) lower fuel costs.

Selling, general and administrative expense. The $2.2 million increase in selling, general and administrative expense for the year ended December 31, 2015 was primarily attributable to a $3.0 million increase in salaries and benefits expenses and a $1.5 million increase in bad debt expense offset by a $1.3 million decrease in transaction expenses and a $1.0 million decrease in professional fees.

Depreciation and amortization expense. The $14.1 million increase in depreciation expense was related to an increase in gross property and equipment balances during the year ended December 31, 2015 compared to gross balances during the year ended December 31, 2014. There is no variance in amortization expense between the periods, as intangible assets are amortized on a straight-line basis and there has been no change in gross identifiable intangible assets between the periods.

(Gain) on sale of assets. The $1.0 million gain on sale of assets during the year ended December 31, 2015 was primarily attributable to $1.2 million cash insurance recoveries on previously impaired compression equipment received during the year and $1.1 million gain on sale of 18 units, or 7,200 horsepower, offset by $1.3 million of losses incurred in the disposal of various unit and non-unit assets.

Impairment of compression equipment. A majority of the $27.3 million impairment charge during the year ended December 31, 2015 resulted from 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 the inability of the equipment to meet current emission standards without retrofitting, this equipment was unlikely to be accepted by customers under current market conditions. As a result of our evaluation during the second quarter of 2015, we determined to retire and either sell or re-utilize the key components of 166 compressor units, or approximately 58,000 horsepower, that had been previously used to provide compression services in our business.

Goodwill impairment. During the fourth quarter of 2015, we recorded 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. There was no impairment of goodwill for the year ended December 31, 2014.

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Interest expense, net. The $5.1 million increase in interest expense, net was primarily attributable to the impact of an approximately $224.6 million increase in average outstanding borrowings under our revolving credit facility, in which average borrowings were $723.3 million for the year ended December 31, 2015 compared to $498.7 million for the year ended December 31, 2014. Our revolving credit facility had an interest rate of 2.26% and 2.16% at December 31, 2015 and 2014, respectively, and a weighted-average interest rate of 2.24% and 2.22% during the years ended December 31, 2015 and 2014, respectively.

Income tax expense. This line item represents the Revised Texas Franchise Tax ("Texas Margin Tax"). The increase in income tax expense for the year ended December 31, 2015 compared to December 31, 2014 was primarily associated with the establishment of a deferred tax liability reflecting the book/tax basis difference in our property and equipment.

Other Financial Data

The following table summarizes other financial data for the periods presented (dollars in thousands):

	Year Ended December 31,			Percent Change	
Other Financial Data: (1)	2016	2015	2014	2016	2015
Gross operating margin	$ 177,760	$ 189,006	$ 147,474	(6.0) %	28.2 %
Gross operating margin percentage (2)	66.8 %	69.9 %	66.6 %	(4.4) %	5.0 %
Adjusted EBITDA	$ 146,648	$ 153,572	$ 114,409	(4.5) %	34.2 %
Adjusted EBITDA percentage (2)	55.2 %	56.8 %	51.6 %	(2.8) %	10.1 %
DCF (3)	$ 118,329	$ 120,850	$ 85,927	(2.1) %	40.6 %
DCF Coverage Ratio (3)	1.00 x	1.17 x	0.99	(14.5)%	18.2 %
Cash Coverage Ratio (3)	1.26 x	2.58 x	2.58	(51.2)%	— %

(1) Gross operating margin, Adjusted EBITDA, DCF, DCF Coverage and Cash Coverage are all non-GAAP financial measures. Definitions of each measure, as well as reconciliations of each measure to its most directly comparable financial measurer(s) calculated and presented in accordance with GAAP, can be found under the caption "Non-GAAP Financial Measures" in Part II, Item 6.

(2) Gross operating margin percentage and Adjusted EBITDA percentage are calculated as a percentage of revenue.

(3) Definitions of DCF and DCF Coverage Ratio can be found under the caption "Non-GAAP Financial Measures" in Part II, Item 6. The DCF and DCF Coverage Ratios presented here are based on a weighted average of units outstanding. For the years ended December 31, 2016, 2015, and 2014 the DCF Coverage Ratio based on the actual units outstanding at the respective record dates was 0.98x, 1.15x, and 0.97x, respectively, and the Cash Coverage Ratio based on actual units outstanding at the respective record dates for these same periods was 1.23x, 2.48x, and 2.46x, respectively.

Adjusted EBITDA. The $6.9 million, or 4.5%, decrease in Adjusted EBITDA during the year ended December 31, 2016 was primarily attributable to $11.2 million lower gross operating margin offset by $4.4 million lower selling, general and administrative expenses, excluding unit-based compensation expense, severance charges and transaction expenses, during the year ended December 31, 2016.

The $39.2 million, or 34.2%, increase in Adjusted EBITDA during the year ended December 31, 2015 was primarily attributable to $41.5 million higher gross operating margin as a result of a 17.3% increase in average revenue generating horsepower during 2015 and an approximate 3.3% increase in gross operating margin percentage due primarily to certain cost savings initiatives, timing of certain preventative maintenance activities and lower fuel costs.

Distributable Cash Flow. The $2.5 million, or 2.1%, decrease in DCF during the year ended December 31, 2016 was primarily due to $11.2 million decrease in gross operating margin, $3.1 million higher cash interest expense, net and $1.1 million lower insurance recoveries received, offset by $8.4 million lower maintenance capital expenditures, $4.4 million lower selling, general and administrative expenses, excluding unit-based compensation expense, severance charges and transaction expenses during the comparable period.

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The $34.9 million, or 40.6%, increase in DCF during the year ended December 31, 2015 was primarily due to increases in the gross operating margin as a result of a 17.3% increase in average revenue generating horsepower during 2015 and an approximate 3.3% increase in gross operating margin percentage due primarily to certain cost savings initiatives, timing of certain preventative maintenance activities and lower fuel costs, partially offset by higher selling, general and administrative expense, higher maintenance capital expenditures, and higher cash interest expense, net.

Coverage Ratios. The disproportionate decrease in Cash Coverage Ratio (as compared to DCF Coverage Ratio) is due to period-to-period decreases in DRIP participation.

Liquidity and Capital Resources

Overview

We operate in a capital-intensive industry, and our primary liquidity needs are to finance the purchase of additional compression units and make other capital expenditures, service our debt, fund working capital, and pay distributions. Our principal sources of liquidity include cash generated by operating activities, borrowings under our revolving credit facility and issuances of debt and equity securities, including under the DRIP.

We believe cash generated by operating activities and, where necessary, borrowings under our revolving credit facility will be sufficient to service our debt, fund working capital, fund our estimated 2017 expansion capital expenditures and fund our maintenance capital expenditures. Because we distribute all of our available cash, which excludes prudent operating reserves, we expect to fund any future expansion capital expenditures or acquisitions primarily with capital from external financing sources, such as borrowings under our revolving credit facility and issuances of debt and equity securities, including under the DRIP.

We are not aware of any regulatory changes or environmental liabilities that we currently expect to have a material impact on our current or future operations. Please see “—Capital Expenditures” below.

Cash Flows

The following table summarizes our sources and uses of cash for the years ended December 31, 2016, 2015 and 2014 (in thousands):

	Year Ended December 31,		
	2016	2015	2014
Net cash provided by operating activities	$ 103,697	$ 117,401	$ 101,891
Net cash used in investing activities	(50,831)	(278,158)	(380,523)
Net cash provided by financing activities	(52,808)	160,758	278,631

Net cash provided by operating activities. The $13.7 million decrease in net cash provided by operating activities for the year ended December 31, 2016 was due primarily to $11.2 million lower gross operating margin, adjustments to non-cash and other items and changes in our working capital.

The $15.5 million increase in net cash provided by operating activities from the year ended December 31, 2014 to the year ended December 31, 2015 relates primarily to a $41.5 million increase in gross operating margin, offset by a $9.4 million increase in inventory purchases, a $6.0 million increase in payroll and benefits payments, a $4.6 million increase in cash interest paid, $3.9 million increase in property tax payments, and a $1.4 million increase in selling, general and administrative expenses, excluding unit-based compensation expense.

Net cash used in investing activities. For the year ended December 31, 2016, net cash used in investing activities related primarily to purchases of new compression units, reconfiguration costs and related equipment. We significantly reduced our purchases of new compression units during 2016 due to the reduced activity levels in the overall energy market.

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For the year ended December 31, 2015, net cash used in investing activities related primarily to purchases of new compression units and related equipment in response to increased demand for our services and maintenance capital expenditures made to maintain or replace existing assets and operating capacity, partially offset by $1.7 million of proceeds from the sale of equipment during 2015 and $1.2 million of proceeds from insurance recoveries on previously impaired compression units during 2015.

For the year ended December 31, 2014, net cash used in investing activities related primarily to the purchase of new compression units and related equipment in response to increased demand and maintenance capital expenditures made to maintain or replace existing assets and operating capacity, partially offset by $1.4 million of proceeds from the sale of equipment during 2014.

Net cash provided by financing activities. During 2016, we paid $43.8 million, on a net basis, on our revolving credit facility from which we borrow primarily to support our purchases of new compression units, reconfiguration costs and related equipment, as described above. During December 2016, we completed a public equity offering and utilized net proceeds of $80.9 million to reduce indebtedness outstanding under our revolving credit facility. Additionally, we paid various loan fees and incurred costs of $2.0 million related to an amendment to our revolving credit facility. During 2016, we made cash distributions to our unitholders of $87.7 million.

During 2015, we borrowed $134.3 million, on a net basis, primarily to support our purchases of new compression units and related equipment, as described above. During September 2015, we completed a public equity offering and utilized net proceeds of $75.1 million to reduce indebtedness outstanding under our revolving credit facility. Additionally, in January 2015, we paid various loan fees and incurred costs of $3.4 million related to an amendment to our revolving credit facility. During 2015, we made cash distributions to our unitholders of $45.1 million.

For the year ended December 31, 2014, we borrowed $173.9 million, on a net basis, primarily to support our purchases of new compression units and related equipment, as described above. During May 2014, we completed an equity offering and utilized the net proceeds of $138.0 million to reduce indebtedness outstanding under our revolving credit facility. Additionally during 2014, we made distributions to our unitholders of $32.3 million.

Equity Offerings

On December 8, 2016, we closed a public offering of 5,175,000 common units at a price to the public of $16.25 per common unit. We used the net proceeds of $80.9 million (net of underwriting discounts and commission and offering expenses) to reduce the indebtedness outstanding under our revolving credit facility

On September 15, 2015, we closed a public offering of 4,000,000 common units at a price to the public of $19.33 per common unit. We used the net proceeds of $74.4 million (net of underwriting discounts and commission and offering expenses) to reduce the indebtedness outstanding under our revolving credit facility.

On May 21, 2015, we issued 34,921 common units in a private placement for $0.7 million in a transaction that was exempt from registration under Section 4(a)(2) of the Securities Act of 1933, as amended (the “Securities Act”). We used the proceeds from the private placement for general partnership purposes.

In May 2014, we closed a public offering of 5,600,000 common units at a price to the public of $25.59 per common unit. We used the net proceeds of $138.0 million (net of underwriting discounts and commission and offering expenses) to reduce the indebtedness outstanding under our revolving credit facility. In connection with this offering, certain selling unitholders sold a combined total of 1,990,000 common units. We did not receive any proceeds from the common units sold by such selling unitholders.

Capital Expenditures

The compression business is capital intensive, requiring significant investment to maintain, expand and upgrade existing operations. Our capital requirements have consisted primarily of, and we anticipate that our capital requirements will continue to consist primarily of, the following:

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- maintenance capital expenditures, which 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; and

- expansion capital expenditures, which are capital expenditures made to expand the operating capacity or operating income capacity of assets, including by acquisition of compression units or through modification of existing compression units to increase their capacity, or to replace certain partially or fully depreciated assets that were not currently generating operating income.

We classify capital expenditures as maintenance or expansion on an individual asset basis. Over the long term, we expect that our maintenance capital expenditure requirements will continue to increase as the overall size and age of our fleet increases. Our aggregate maintenance capital expenditures for the years ended December 31, 2016 and 2015 were $7.7 million and $16.1 million, respectively. We currently plan to spend approximately $12 million in maintenance capital expenditures during 2017 including parts consumed from inventory and property and equipment.

We anticipate that our 2017 expansion capital expenditures will be substantially similar to our 2016 capital expenditures levels. Without giving effect to any equipment we may acquire pursuant to any future acquisitions, we currently have budgeted between $50 million and $60 million in expansion capital expenditures during 2017. Our expansion capital expenditures for the years ended December 31, 2016 and 2015 were $40.9 million and $249.7 million, respectively. Previously reported expansion capital expenditures for the year ended December 31, 2015 included the change in capital expenditures included in accounts payable and accrued liabilities as of December 31, 2015.

Revolving Credit Facility

As of December 31, 2016, we were in compliance with all of our covenants under our revolving credit facility. As of December 31, 2016, we had outstanding borrowings under our revolving credit facility of $685.4 million, $414.6 million of borrowing base availability and, subject to compliance with the applicable financial covenants, available borrowing capacity of $152.3 million. The borrowing base consists of eligible accounts receivable, inventory and compression units. Financial covenants permit a maximum leverage ratio of (A) 5.75 to 1.0 as of the end of the fiscal quarter ending December 31, 2016, (B) 5.50 to 1.0 as of the end of the respective fiscal quarters ending March 31, 2017 and June 30, 2017, (C) 5.25 to 1.0 as of the end of the respective fiscal quarters ending September 30, 2017 and December 31, 2017 and (D) 5.00 to 1.0 thereafter. As of February 9, 2017, we had outstanding borrowings of $688.6 million. We expect to remain in compliance with our covenants throughout 2017. If our current cash flow projections prove to be inaccurate, we expect to be able to remain in compliance with such financial covenants by one or more of the following actions: issue equity in conjunction with the acquisition of another business; issue equity in a public or private offering; request a modification of our covenants from our bank group; reduce distributions from our current distribution rate or obtain an equity infusion pursuant to the terms of our revolving credit facility.

For a detailed description of our revolving credit facility including the covenants and restrictions contained therein, please refer to Note 7 to our consolidated financial statements.

Distribution Reinvestment Plan

During the year ended December 31, 2016, distributions of $31.8 million were reinvested under the DRIP resulting in the issuance of 2.7 million common units. Such distributions are treated as non-cash transactions in the accompanying Consolidated Statements of Cash Flows included under Part IV, Item 15 of this report.

For a more detailed description of the DRIP, please refer to Note 8 to our consolidated financial statements.

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Continuous Offering Program

On November 12, 2014, we entered into an Equity Distribution Agreement with the sales agents party thereto, which established our continuous offering program whereby we may issue common units having an aggregate offering amount of up to $150 million (the "COP"). We did not issue any common units or receive any proceeds under the COP in the year ended December 31, 2016 or 2015.

Total Contractual Cash Obligations

The following table summarizes our total contractual cash obligations as of December 31, 2016:

	Payments Due by Period				
Contractual Obligations	Total	1 year	2 - 3 years	4 - 5 years	More than 5 years
	(in thousands)				
Long-term debt (1)	$ 685,371	$ —	$ —	$ 685,371	$ —
Interest on long-term debt obligations (2)	60,781	20,150	40,300	331	—
Equipment/capital purchases (3)	17,912	17,912	—	—	—
Operating lease obligations (4)	4,337	1,586	2,580	171	—
Total contractual cash obligations	$ 768,401	$ 39,648	$ 42,880	$ 685,873	$ —

(1) We assumed that the amount outstanding under our revolving credit facility at December 31, 2016 would be repaid in January 2020, the maturity date of the facility.
(2) Represents future interest payments under our revolving credit facility based on the interest rate as of December 31, 2016 of 2.94%.
(3) Represents commitments for new compression units that are being fabricated, and is a component of our overall projected expansion capital expenditures during 2017 of $50 million to $60 million.
(4) Represents commitments for future minimum lease payments on noncancelable leases.

Effects of Inflation. Our revenues and results of operations have not been materially impacted by inflation and changing prices in the past three fiscal years.

Off-Balance Sheet Arrangements

We have no off-balance sheet financing activities. Please refer to Note 13 of our consolidated financial statements included in this report for a description of our commitments and contingencies.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations is based upon our financial statements. These financial statements were prepared in conformity with GAAP. As such, we are required to make certain estimates, judgments and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the periods presented. We base our estimates on historical experience, available information and various other assumptions we believe to be reasonable under the circumstances. On an ongoing basis, we evaluate our estimates; however, actual results may differ from these estimates under different assumptions or conditions. The accounting policies that we believe require management's most difficult, subjective or complex judgments and are the most critical to its reporting of results of operations and financial position are as follows:

Revenue Recognition

We recognize revenue using the following criteria: (i) persuasive evidence of an arrangement; (ii) delivery has occurred or services have been rendered; (iii) the customer's price is fixed or determinable; and (iv) collectability is reasonably assured.

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Revenue from compression services is recognized ratably under our fixed-fee contracts over the term of the contract as compression services are provided to our customers. Compression services generally are billed monthly, one month in advance of the commencement of the service month, except for certain customers who are billed at the beginning of the service month. Amounts invoiced in advance are recorded as deferred revenue on the balance sheet until earned, at which time it is recognized as revenue.

Revenue and the associated expense from installation services, which includes the installation of stations for our customers, is recorded using the percentage-of-completion method measured using the efforts-expended method. In applying the percentage-of-completion method, we use the percentage of total workflows to date that have been completed relative to estimated total workflows to be completed in order to estimate the progress towards completion to determine the amount of revenue and profit to recognize for each contract.

The percentage-of-completion method of revenue recognition requires us to make estimates of contract revenues and costs to complete our projects. In making such estimates, management judgments are required to evaluate significant assumptions including the cost of materials and labor, expected labor productivity, the impact of potential variances in schedule completion, the amount of net contract revenues and the impact of any penalties, claims, change orders, or performance incentives.

Business Combinations and Goodwill

Goodwill acquired in connection with business combinations represents the excess of consideration over the fair value of net assets acquired. Certain assumptions and estimates are employed in determining the fair value of assets acquired and liabilities assumed. Goodwill is not amortized, but is reviewed for impairment annually based on the carrying values as of October 1, or more frequently if impairment indicators arise that suggest the carrying value of goodwill may not be recovered.

Goodwill—Impairment Assessments

We evaluate goodwill for impairment annually on October 1 of the fiscal year and whenever events or changes indicate that it is more likely than not that the fair value of our single business reporting unit could be less than its carrying value (including goodwill). The timing of the annual test may result in charges to our statement of operations in our fourth fiscal quarter that could not have been reasonably foreseen in prior periods.

We estimate the fair value of our reporting unit based on a number of factors, including the potential value we would receive if we sold the reporting unit, enterprise value, discount rates and projected cash flows. Estimating projected cash flows requires us to make certain assumptions as it relates to future operating performance. When considering operating performance, various factors are considered such as current and changing economic conditions and the commodity price environment, among others. Due to the imprecise nature of these projections and assumptions, actual results can and often do, differ from our estimates. If the growth assumptions embodied in the current year impairment testing prove inaccurate, we could incur an impairment charge in the future.

On October 1, 2016, we performed our annual goodwill impairment test, wherein we compared the estimated fair value of our single reporting unit to its carrying value. The estimated fair value of our reporting unit, measured based on market capitalization, as of October 1, 2016 exceeded its carrying value in excess of 20% and we concluded that our goodwill was not impaired. We recorded no goodwill impairment charges for the twelve months ended December 31, 2016. We had approximately $35.9 million of goodwill recorded on the balance sheet as of December 31, 2016.

On October 1, 2015, we performed our annual goodwill impairment test and concluded that our goodwill was not impaired. We updated our impairment test as of December 31, 2015 as certain potential impairment indicators were identified during the fourth quarter, specifically (1) the decline in the market price of our common units, (2) the sustained decline in global commodity prices, and (3) the decline in performance of the Alerian MLP Index, which indicated the reporting unit had a fair value that was less than its carrying value as of December 31, 2015. We prepared a quantitative assessment as of December 31, 2015 which indicated that the calculated fair value was less than the carrying value. We

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subsequently performed “Step 2” impairment test for our reporting unit under which we treated our business as if it had been acquired in a business combination as of December 31, 2015 and assigned the fair value of the reporting unit to all of our assets and liabilities. The carrying value of the goodwill was compared to the new implied fair value of goodwill and an impairment was recognized for the amount of the carrying value that exceeded the implied fair value. Based on that step two impairment test, we recognized a non-cash impairment charge of $172.2 million. We had approximately $35.9 of goodwill remaining on the balance sheet as of December 31, 2015 following this impairment.

As discussed above, estimates of fair value can be affected by a variety of external and internal factors. The recent crude oil price volatility has caused disruptions in global energy industries and markets. Potential events or circumstances that could reasonably be expected to negatively affect the key assumptions we used in estimating the fair value of our reporting unit include the consolidation or failure of crude oil and natural gas producers, which may result in a smaller market for services and may cause us to lose key customers, and cost-cutting efforts by crude oil and natural gas producers, which may cause us to lose current or potential customers or achieve less revenue per customer. We continue to monitor the remaining $35.9 million of goodwill and if the estimated fair value of our reporting unit declines due to any of these or other factors, we may be required to record future goodwill impairment charges.

Long-Lived Assets

Long-lived assets, which include property and equipment, and intangible assets, comprise a significant amount of our total assets. Long-lived assets to be held and used by us are reviewed to determine whether any events or changes in circumstances indicate the carrying amount of the asset may not be recoverable. For long-lived assets to be held and used, we base our evaluation on impairment indicators such as the nature of the assets, the future economic benefit of the assets, the consistency of performance characteristics of compression units in our idle fleet with the performance characteristics of our revenue generating horsepower, any historical or future profitability measurements and other external market conditions or factors that may be present. If such impairment indicators are present or other factors exist that indicate the carrying amount of the asset may not be recoverable, we determine whether an impairment has occurred through the use of an undiscounted cash flows analysis. If an impairment has occurred, we recognize a loss for the difference between the carrying amount and the estimated fair value of the asset. The fair value of the asset is measured using quoted market prices or, in the absence of quoted market prices, is based on an estimate of discounted cash flows, the expected net sale proceeds compared to other similarly configured fleet units we recently sold, a review of other units recently offered for sale by third parties, or the estimated component value of similar equipment we plan to continue to use. We recorded $5.8 million, $27.3 million and $2.3 million in impairment of compression equipment for the years ended December 31, 2016, 2015 and 2014, respectively.

Potential events or circumstances that could reasonably be expected to negatively affect the key assumptions we used in estimating whether or not the carrying value of our long-lived assets are recoverable include the consolidation or failure of crude oil and natural gas producers, which may result in a smaller market for services and may cause us to lose key customers, and cost-cutting efforts by crude oil and natural gas producers, which may cause us to lose current or potential customers or achieve less revenue per customer. If our projections of cash flows associated with our units decline, we may have to record an impairment of compression equipment in future periods.

Allowances and Reserves

We maintain an allowance for bad debts based on specific customer collection issues and historical experience. The determination of the allowance for doubtful accounts requires us to make estimates and judgments regarding our customers' ability to pay amounts due. On an ongoing basis, we conduct an evaluation of the financial strength of our customers based on payment history, the overall business climate in which our customers operate and specific identification of customer bad debt and make adjustments to the allowance as necessary. Our evaluation of our customers' financial strength is based on the aging of their respective receivables balance, customer correspondence, financial information and third-party credit ratings. Our evaluation of the business climate in which our customers operate is based on a review of various publicly-available materials regarding our customers' industries, including the solvency of various companies in the industry. The allowance for doubtful accounts was $0.7 million and $2.1 million as of December 31, 2016 and 2015, respectively. During the year ended December 31, 2016, we decreased our allowance for doubtful accounts by $1.1 million due mostly to collections on accounts that had previously been reserved, and

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additionally wrote-off $0.3 million of accounts that had been previously reserved. The allowance for doubtful accounts was increased during the twelve months ended December 31, 2015 due to our evaluation of the aforementioned factors during that year. Since the overall energy industry continues to be volatile, it is not certain that the factors leading to an increase in the allowance for doubtful accounts during 2015, or the subsequent decrease during 2016, will continue. Due to the decrease in the allowance for doubtful accounts during 2016, we recognized a reduction of bad debt expense of $1.1 million for the year ended December 31, 2016. Bad debt expense for the year ended December 31, 2015 was $1.8 million.

Recent Accounting Pronouncements

We qualify as an emerging growth company under Section 109 of the Jumpstart Our Business Startups, ("JOBS") Act. An emerging growth company can take advantage of the extended transition period provided in Section 7(a)(2)(B) of the Securities Act for complying with new or revised accounting standards. In other words, an emerging growth company can delay the adoption of certain accounting standards until those standards would otherwise apply to private companies. However, we have chosen to "opt out" of such extended transition period, and as a result, are compliant with new or revised accounting standards on the relevant dates on which adoption of such standards is required for non-emerging growth companies. Section 108 of the JOBS Act provides that our decision to opt out of the extended transition period for complying with new or revised accounting standards is irrevocable.

For more discussion on specific recent accounting pronouncements affecting us, please see Note 12 to our consolidated financial statements.

ITEM 7A.Quantitative and Qualitative Disclosures About Market Risk

Commodity Price Risk

Market risk is the risk of loss arising from adverse changes in market rates and prices. We do not take title to any natural gas or crude oil in connection with our services and, accordingly, have no direct revenue exposure to fluctuating commodity prices. However, the demand for our compression services depends upon the continued demand for, and production of, natural gas and crude oil. Lower natural gas prices or crude oil prices over the long term could result in a decline in the production of natural gas or crude oil, which could result in reduced demand for our compression services. We do not intend to hedge our indirect exposure to fluctuating commodity prices. A 1% decrease in average revenue generating horsepower of our active fleet during the year ended December 31, 2016 would have resulted in a decrease of approximately $2.5 million and $1.7 million in our revenue and gross operating margin, respectively. Gross operating margin is a non-GAAP financial measure. For a reconciliation of gross operating margin to net income (loss), its most directly comparable financial measure, calculated and presented in accordance with GAAP, please read Part II, Item 6 ("—Non-GAAP Financial Measures"). Please also read Part I, Item 1A

("Risk Factors—Risks Related to Our Business—A long-term reduction in the demand for, or production of, natural gas or crude oil in the locations where we operate 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").

Interest Rate Risk

We are exposed to market risk due to variable interest rates under our financing arrangements.

As of December 31, 2016, we had approximately $685.4 million of variable-rate outstanding indebtedness at a weighted-average interest rate of 2.55%. A 1% increase in the effective interest rate on our variable-rate outstanding debt as of December 31, 2016 would result in an annual increase in our interest expense of approximately $6.9 million.

For further information regarding our exposure to interest rate fluctuations on our debt obligations, see Note 7 to our consolidated financial statements. Although we do not currently hedge our variable rate debt, we may, in the future, hedge all or a portion of such debt.

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Credit Risk

Our credit exposure generally relates to receivables for services provided. If any significant customer of ours should have credit or financial problems resulting in a delay or failure to repay the service fees owed to us, this could have a material adverse effect on our business, financial condition, results of operations or cash flows.

ITEM 8.Financial Statements and Supplementary Data

The financial statements and supplementary information specified by this Item are presented in Part IV, Item 15.

ITEM 9.Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None.

ITEM 9A.Controls and Procedures

Disclosure Controls and Procedures

As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosures, and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective as of December 31, 2016 at the reasonable assurance level.

Management’s Annual Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting for us. Our internal control system was designed to provide reasonable assurance regarding the preparation and fair presentation of our published financial statements.

There are inherent limitations to the effectiveness of any control system, however well designed, including the possibility of human error and the possible circumvention or overriding of controls. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Management must make judgments with respect to the relative cost and expected benefits of any specific control measure. The design of a control system also is based in part upon assumptions and judgments made by management about the likelihood of future events, and there can be no assurance that a control will be effective under all potential future conditions. As a result, even an effective system of internal control over financial reporting can provide no more than reasonable assurance with respect to the fair presentation of financial statements and the processes under which they were prepared.

Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2016. In making this assessment, management used the criteria set forth by the 2013 Committee of Sponsoring Organizations of the Treadway Commission in Internal Control — Integrated Framework. Based on this assessment, our management believes that, as of December 31, 2016, our internal control over financial reporting was effective. This report does not include an attestation report of the company’s registered public accounting firm due to a transition period established by rules of the SEC for emerging growth companies.

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Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) during the last fiscal quarter that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B.Other Information

None.

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PART III

ITEM 10.Directors, Executive Officers and Corporate Governance

Board of Directors

Our general partner, USA Compression GP, LLC, manages our operations and activities. Our general partner is not elected by our unitholders and is not subject to re-election on a regular basis in the future. Our general partner has a board of directors that manages our business.

The board of directors of our general partner is currently comprised of seven members, all of whom have been designated by USA Compression Holdings and three of whom are independent as defined under the independence standards established by the NYSE. The NYSE does not require a listed limited partnership like us to have a majority of independent directors on the board of directors of our general partner or to establish a compensation committee or a nominating committee.

The non-management members of our general partner's board of directors regularly meet in executive session without the management members of our general partner's board of directors. Mr. Long, our President and Chief Executive Officer, is currently the only management member of our general partner's board of directors. Forrest E. Wylie presides at such meetings. Interested parties can communicate directly with non-management members of our general partners' board of directors by mail in care of the General Counsel and Secretary at USA Compression Partners, LP, 100 Congress Avenue, Suite 450, Austin, Texas 78701. Such communications should specify the intended recipient or recipients. Commercial solicitations or communications will not be forwarded.

Independent Directors. The board of directors of our general partner has determined that Robert F. End, John D. Chandler and Forrest E. Wylie are independent directors under the standards established by the NYSE and the Exchange Act. The board of directors of our general partner considered all relevant facts and circumstances and applied the independent guidelines of the NYSE and the Exchange Act in determining that none of these directors has any material relationship with us, our management, our general partner or its affiliates or our subsidiaries.

In addition, in October 2014, Mr. Chandler was appointed to serve on the board of directors and the audit committee of one of our customers. For the year ended December 31, 2016, subsidiaries of this customer made compression service payments to us of approximately $8.5 million. The board of directors of our general partner made a

determination that the relationship with this customer did not preclude the independence of Mr. Chandler.

Audit Committee. The board of directors of our general partner has appointed an audit committee comprised solely of directors who meet the independence and experience standards established by the NYSE and the Exchange Act. The audit committee consists of Robert F. End, John D. Chandler and Forrest E. Wylie. Mr. Chandler serves as chairman of the audit committee. The board of directors of our general partner has determined that Mr. Chandler is an "audit committee financial expert" as defined in Item 407(d)(5)(ii) of SEC Regulation S-K, and that each of Messrs. End, Chandler and Wylie is "independent" within the meaning of the applicable NYSE and Exchange Act rules regulating audit committee independence. The audit committee assists the board of directors of our general partner in its oversight of the integrity of our financial statements and our compliance with legal and regulatory requirements and corporate policies and controls. The audit committee has the sole authority to retain and terminate our independent registered public accounting firm, approve all auditing services and related fees and the terms thereof, and pre-approve any non-audit services to be rendered by our independent registered public accounting firm. The audit committee is also responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm will be given unrestricted access to the audit committee. A copy of the charter of the audit committee is available under the Investor Relations tab on our website at usacompression.com. We also will provide a copy of the charter of the audit committee to any of our unitholders without charge upon written request to Investor Relations, 100 Congress Avenue, Suite 450, Austin, TX 78701.

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Compensation Committee. The NYSE does not require a listed limited partnership like us to have a compensation committee. However, the board of directors of our general partner has established a compensation committee to, among other things, oversee the compensation plans described below in Part III, Item 11 ("Executive Compensation"). The compensation committee consists of Robert F. End, William H. Shea, Jr. and Olivia C. Wassenaar. The compensation committee establishes and reviews general policies related to our compensation and benefits. The compensation committee has the responsibility to determine and make recommendations to the board of directors of our general partner with respect to, the compensation and benefits of the board of directors and executive officers of our general partner. A copy of the charter of the compensation committee is available under the Investor Relations tab on our website at usacompression.com. We also will provide a copy of the charter of the compensation committee to any of our unitholders without charge upon written request to Investor Relations, 100 Congress Avenue, Suite 450, Austin, TX 78701.

Conflicts Committee. As set forth in the limited liability company agreement of our general partner, our general partner may, from time to time, establish a conflicts committee to which the board of directors of our general partner will appoint independent directors and which may be asked to review specific matters that the board of directors of our general partner believes may involve conflicts of interest between us, our limited partners and USA Compression Holdings. The conflicts committee will determine the resolution of the conflict of interest in any manner referred to it in good faith. The members of the conflicts committee may not be officers or employees of our general partner or directors, officers or employees of its affiliates, including USA Compression Holdings, and must meet the independence and experience standards established by the NYSE and the Exchange Act to serve on an audit committee of a board of directors of our general partner, and certain other requirements. Any matters approved by the conflicts committee in good faith will be conclusively deemed to be fair and reasonable to us, approved by all of our partners and not a breach by our general partner of any duties it may owe us or our unitholders.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires the board of directors and executive officers of our general partner, and persons who own more than 10 percent of a registered class of our equity securities, to file with the SEC and any exchange or other system on which such securities are traded or quoted initial reports of ownership and reports of changes in ownership of our common units and other equity securities. Officers, directors and greater than 10 percent unitholders are required by the SEC's regulations to furnish to us and any exchange or other system on which such securities are traded or quoted with copies of all Section 16(a) forms they filed with the SEC. To our knowledge, based solely on a review of the copies of such reports furnished to us, we believe that all reporting obligations of the officers and directors of our general partner and greater than 10 percent unitholders under Section 16(a) were satisfied during the year ended December 31, 2016.

Corporate Governance Guidelines and Code of Ethics

The board of directors of our general partner has adopted Corporate Governance Guidelines that outline important policies and practices regarding our governance and provide a framework for the function of the board of directors of our general partner and its committees. The board of directors of our general partner has also adopted a Code of Business Conduct and Ethics (the "Code") that applies to our general partner and its subsidiaries and affiliates, including us, and to all of its and their directors, employees and officers, including its principal executive officer, principal financial officer and principal accounting officer. Copies of the Corporate Governance Guidelines and the Code are available under the Investor Relations tab on our website at usacompression.com. We also will provide copies of the Corporate Governance Guidelines and the Code to any of our unitholders without charge upon written request to Investor Relations, 100 Congress Avenue, Suite 450, Austin, TX 78701.

Reimbursement of Expenses of Our General Partner

Our general partner will not receive any management fee or other compensation for its management of us. Our general partner and its affiliates will be reimbursed for all expenses incurred on our behalf, including the compensation of employees of our general partner or its affiliates that perform services on our behalf. These expenses include all expenses necessary or appropriate to the conduct of our business and that are allocable to us. Our partnership agreement

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provides that our general partner will determine in good faith the expenses that are allocable to us. There is no cap on the amount that may be paid or reimbursed to our general partner or its affiliates for compensation or expenses incurred on our behalf.

Directors and Executive Officers

The following table shows information as of February 9, 2017 regarding the current directors and executive officers of USA Compression GP, LLC.

Name	Age	Position with USA Compression GP, LLC
Eric D. Long	58	President and Chief Executive Officer and Director
William G. Manias	54	Vice President and Chief Operating Officer
Matthew C. Liuzzi	42	Vice President, Chief Financial Officer and Treasurer
Christopher W. Porter	33	Vice President, General Counsel and Secretary
David A. Smith	54	Vice President and President, Northeast Region
Sean T. Kimble	52	Vice President, Human Resources
John D. Chandler	47	Director
Jim H. Derryberry	72	Director
Robert F. End	61	Director
William H. Shea, Jr.	62	Director
Olivia C. Wassenaar	37	Director
Forrest E. Wylie	53	Director

The directors of our general partner hold office until the earlier of their death, resignation, removal or disqualification or until their successors have been elected and qualified. Officers serve at the discretion of the board of directors of our general partner. There are no family relationships among any of the directors or executive officers of our general partner.

Eric D. Long has served as our President and Chief Executive Officer since September 2002 and has served as a director of USA Compression GP, LLC since June 2011. Mr. Long co-founded USA Compression in 1998 and has over 35 years of experience in the oil and gas industry. From 1980 to 1987, Mr. Long served in a variety of technical and managerial roles for several major pipeline and oil and natural gas producing companies, including Bass Enterprises Production Co. and Texas Oil & Gas. Mr. Long then served in a variety of senior officer level operating positions with affiliates of Hanover Energy, Inc., a company primarily engaged in the business of gathering, compressing and transporting natural gas. In 1993, Mr. Long co-founded Global Compression Services, Inc., a compression services company. Mr. Long was formerly on the board of directors of the Wiser Oil Company, an NYSE listed company from May 2001 until it was sold to Forest Oil Corporation in May 2004. Mr. Long received his bachelor’s degree, with honors, in Petroleum Engineering from Texas A&M University. He is a registered Professional Engineer in the state of Texas.

As a result of his professional background, Mr. Long brings to us executive level strategic, operational and financial skills. These skills, combined with his over 35 years of experience in the oil and natural gas industry, including in particular his experience in the compression services sector, make Mr. Long a valuable member of the board of directors of our general partner.

William G. Manias has served as our Vice President and Chief Operating Officer since July 2013. He served as a director of our general partner from February 2013 to July 2013. From October 2009 until January 2013, Mr. Manias served as Senior Vice President and Chief Financial Officer of Crestwood Midstream Partners LP and its affiliates, where his general responsibilities included managing the partnership's financial and treasury activities. Before joining Crestwood in January 2009, Mr. Manias was the Chief Financial Officer of TEPPCO Partners, L.P. starting in January 2006. From September 2004 until January 2006, he served as Vice President of Business Development and Strategic Planning at Enterprise Product Partners L.P. He previously served as Vice President and Chief Financial Officer of GulfTerra Energy Partners, L.P. from February 2004 to September 2004 at which time GulfTerra Energy Partners, L.P. was merged with Enterprise Product Partners L.P. Prior to GulfTerra Energy Partners, L.P., Mr. Manias

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held several executive management positions with El Paso Corporation. Prior to El Paso, he worked as an energy investment banker for J.P. Morgan Securities Inc. and its predecessor companies from May 1992 to August 2001. Mr. Manias earned a B.S.E. in civil engineering from Princeton University in 1984, a M.S. in petroleum engineering from Louisiana State University in 1986 and an M.B.A. from Rice University in 1992.

Matthew C. Liuzzi has served as our Vice President, Chief Financial Officer and Treasurer since January 2015. Prior to such time, Mr. Liuzzi served as our Senior Vice President – Strategic Development since joining us in April 2013. Mr. Liuzzi joined us after nine years in investment banking, since 2008 at Barclays, where he was most recently a Director in the Global Natural Resources Group in Houston. At Barclays, Mr. Liuzzi worked primarily with midstream clients on a variety of investment banking assignments, including initial public offerings, public and private debt and equity offerings, as well as strategic advisory assignments. He holds a B.A. and an M.B.A., both from the University of Virginia.

Christopher W. Porter has served as our Vice President, General Counsel and Secretary since January 2017, and, prior to that, had served as our Associate General Counsel and Assistant Secretary since October 2015. From January 2010 through October 2015, Mr. Porter practiced corporate and securities law at Andrews Kurth Kenyon LLP, representing public and private companies, including master limited partnerships, in capital markets offerings and mergers and acquisitions. Mr. Porter holds a B.B.A. degree from Texas A&M University, a M.S. degree from Texas A&M University, and a J.D. degree from The George Washington University.

David A. Smith has served as our President, Northeast Region since joining us in November 1998 and was appointed corporate Vice President in June 2011. Mr. Smith has approximately 20 years of experience in the natural gas compression industry, primarily in operations and sales. From 1985 to 1989, Mr. Smith was a sales manager for McKenzie Corporation, a compression fabrication company. From 1989 to 1996, Mr. Smith held positions of General Manager and Regional Manager of Northeast Division with Compressor Systems Inc., a fabricator and supplier of compression services. Mr. Smith was the Regional Manager in the northeast for Global Compression Services, Inc., a compression services company, and served in that capacity from 1996 to 1998. Mr. Smith received an associates degree in Automotive and Diesel Technology from Rosedale Technical Institute.

Sean T. Kimble has served as our Vice President, Human Resources since June 2014. Mr. Kimble comes to us with over twenty years of human resources leadership experience. Prior to joining the company, he was most recently the Senior Vice President of Human Resources at Millard Refrigerated Services from January 2011 to May 2014 where he led all aspects of human resources. Before joining Millard, he was the Chief Administrative Officer and Executive Vice President of Human Resources at MV Transportation from March 2005 to February 2009 where he led human resources, safety, labor relations and various other operating support functions. Mr. Kimble holds a B.S. from Sacramento State University and an M.B.A. from Saint Mary’s College of California.

John D. Chandler has served as a director of USA Compression GP, LLC since October 2013. Mr. Chandler has also served on the board of directors and the audit committee of CONE Midstream GP, LLC since October 2014 and on

the board of directors and audit committee of Green Plains Holdings LLC since June 2016. From 2009 to March 2014, Mr. Chandler served as Senior Vice President and Chief Financial Officer of Magellan GP, LLC, the general partner of Magellan Midstream Partners, LP. From 2003 until 2009, he served in the same capacities for the general partner of Magellan Midstream Holdings, L.P. From 1999 to 2002, Mr. Chandler was Director of Financial Planning and Analysis and Director of Strategic Development for a subsidiary of The Williams Companies, Inc. From 1992 to 1999, Mr. Chandler held various accounting and finance positions with MAPCO Inc. Mr. Chandler received his B.S. and B.A. in accounting and finance from the University of Tulsa.

Mr. Chandler's experience in the energy industry, particularly through his position as the Chief Financial Officer of the general partner of Magellan Midstream Partners, LP, provides additional industry perspective to the board of directors of our general partner. He brings us helpful perspective regarding company growth, having been an officer at Magellan since its spin-off from the Williams Companies in 2003. In addition, his understanding of the midstream master limited partnership sector in particular and of the unique issues related to operating publicly traded limited partnerships help him make valuable contributions to us.

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Jim H. Derryberry has served as a director of USA Compression GP, LLC since January 2013. From February 2005 to October 2006, Mr. Derryberry served on the board of directors of Magellan GP, LLC, the general partner of Magellan Midstream Partners, L.P. Mr. Derryberry served as chief operating officer and chief financial officer of Riverstone Holdings, LLC until 2006 and currently serves as a special advisor. Prior to joining Riverstone, Mr. Derryberry was a managing director of J.P. Morgan, where he served as head of the Natural Resources and Power Group. Before joining J.P. Morgan, Mr. Derryberry was in the Goldman Sachs Global Energy and Power Group where he was responsible for mergers and acquisitions, capital markets financing and the management of relationships with major energy companies. He has also served as an advisor to the Russian government for energy privatization. Mr. Derryberry has served as a member of the Board of Overseers for the Hoover Institution at Stanford University and is a member of the Engineering Advisory Board at the University of Texas at Austin. He received his B.S. and M.S. degrees in engineering from the University of Texas at Austin and earned an M.B.A. from Stanford University.

Mr. Derryberry brings significant knowledge and expertise to the board of directors of our general partner from his service on other boards and his years of experience in our industry including his useful insight into investments and proven leadership skills as a managing director of Riverstone Holdings, LLC. As a result of his experience and skills, we believe Mr. Derryberry is a valuable member of the board of directors of our general partner.

Robert F. End has served as a director of USA Compression GP, LLC since November 2012. Mr. End served as a director of Hertz Global Holdings, Inc. from December 2005 until August 2011. Mr. End was a Managing Director of Transportation Resource Partners, a private equity firm from 2009 through 2011. Prior to joining TRP in 2009, Mr. End had been a Managing Director of Merrill Lynch Global Private Equity Division (“MLGPE”), the private equity arm of Merrill Lynch & Co., Inc., where he served as Co-Head of the North American Region, and a Managing Director of Merrill Lynch Global Private Equity, Inc., the Manager of ML Global Private Equity Fund, L.P., a proprietary private equity fund which he joined in 2004. Previously, Mr. End was a founding Partner and Director of Stonington Partners Inc., a private equity firm established in 1994. Prior to leaving Merrill Lynch in 1994, Mr. End was a Managing Director of Merrill Lynch Capital Partners, Merrill Lynch’s private equity group. Mr. End joined Merrill Lynch in 1986 and worked in the Investment Banking Division before joining the private equity group in 1989. Mr. End received his A.B. from Dartmouth College and his M.B.A. from the Tuck School of Business Administration at Dartmouth College.

Mr. End brings significant knowledge and expertise to the board of directors of our general partner from his service on other boards and his years of experience with private equity groups, including his useful insight into investments and business development and proven leadership skills as Managing Director of MLGPE. As a result of this experience and resulting skills set, we believe Mr. End is a valuable member of the board of directors of our general partner.

William H. Shea, Jr. has served as a director of USA Compression GP, LLC since June 2011. Mr. Shea served as the chairman of the board of directors, President and Chief Executive Officer of Niska Gas Storage Partners LLC from May 2014 to July 2016. Previously, Mr. Shea served as the President and Chief Operating Officer of Buckeye GP LLC and its predecessor entities (“Buckeye”), from July 1998 to September 2000, as President and Chief Executive Officer of Buckeye from September 2000 to July 2007, and Chairman from May 2004 to July 2007. From August 2006 to July 2007, Mr. Shea served as Chairman of MainLine Management LLC, the general partner of

Buckeye GP Holdings, L.P., and as President and Chief Executive Officer of MainLine Management LLC from May 2004 to July 2007. Mr. Shea served as a director of Penn Virginia Corp. from July 2007 to March 2010, and as President and Chief Executive Officer of the general partner of Penn Virginia GP Holdings, L.P. from March 2010 to October 2013 and as Chief Executive Officer of the general partner of PVR Partners, L.P. ("PVR"), from March 2010 to October 2013. Mr. Shea has also served as a director of Kayne Anderson Energy Total Return Fund, Inc., and Kayne Anderson MLP Investment Company since March 2008 and Niska Gas Storage Partners LLC from May 2010 to July 2016. Mr. Shea has an agreement with Riverstone, pursuant to which he has agreed to serve on the boards of certain Riverstone portfolio companies. Mr. Shea received his B.A. from Boston College and his M.B.A. from the University of Virginia.

Mr. Shea's experiences as an executive with both PVR and Buckeye, energy companies that operate across a broad spectrum of sectors, including coal, natural gas gathering and processing and refined petroleum products transportation, have given him substantial knowledge about our industry. In addition, Mr. Shea has substantial experience overseeing the strategy and operations of publicly traded partnerships. As a result of this experience and resulting skill set, we believe Mr. Shea is a valuable member of the board of directors of our general partner.

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Olivia C. Wassenaar has served as a director of USA Compression GP, LLC since June 2011. Ms. Wassenaar was an Associate with Goldman, Sachs & Co. in the Global Natural Resources investment banking group from July 2007 to August 2008, where she focused on mergers, equity and debt financings and leveraged buyouts for energy, power and renewable energy companies. Ms. Wassenaar joined Riverstone in September 2008 as Vice President, and has served as a Principal from May 2010 to February 2014 and as a Managing Director since February 2014. In this capacity, she invests in and monitors investments in the midstream and exploration & production sectors of the energy industry. Ms. Wassenaar has also served on the board of directors of Northern Blizzard Resources Inc. since June 2011 and on the board of directors of the general partner of Niska Gas Storage Partners LLC from July 2014 to July 2016, as well as various private portfolio companies sponsored by Riverstone. Ms. Wassenaar received her A.B., magna cum laude, from Harvard College and earned an M.B.A. from the Wharton School of the University of Pennsylvania.

Ms. Wassenaar's experience in evaluating financial and strategic options and the operations of companies in our industry and as an investment banker make her a valuable member of the board of directors of our general partner.

Forrest E. Wylie has served as a director of USA Compression GP, LLC since March 2013. Mr. Wylie is also a Senior Operating Partner at Stonepeak Infrastructure Partners and has served in such role since October 2013. Mr. Wylie served as the Non-Executive Chairman of the board of directors of Buckeye GP LLC, the general partner of Buckeye Partners, L.P., from February 2012 to August 2014. He served as Chairman of the Board, CEO and a director of Buckeye GP LLC from June 2007 to February 2012. Mr. Wylie also served as a director of the general partner of Buckeye GP Holdings L.P., the former parent company of Buckeye ("BGH") from June 2007 until the merger of BGH with Buckeye Partners, L.P. on November 2010. Prior to his appointment, he served as Vice Chairman of Pacific Energy Management LLC, an entity affiliated with Pacific Energy Partners, L.P., a refined product and crude oil pipeline and terminal partnership, from March 2005 until Pacific Energy Partners, L.P. merged with Plains All American, L.P. in November 2006. Mr. Wylie was President and CFO of NuCoastal Corporation, a midstream energy company, from May 2002 until February 2005. From November 2006 to June 2007, Mr. Wylie was a private investor. Mr. Wylie served on the board of directors and the audit committee of Coastal Energy Company, a publicly traded entity, until April 2011. Mr. Wylie also served on board of directors and compensation and nominating and corporate governance committees of Eagle Bulk Shipping Inc. until May 2010. Mr. Wylie also currently serves as Executive Chairman of Ajax Resources LLC and a board member of Paradigm Energy Partners.

Mr. Wylie's experience in the energy industry, through his prior position as the CEO of a publicly traded partnership and the past employment described above, has given him both an understanding of the midstream sector of the energy business and of the unique issues related to operating publicly traded limited partnerships that make him a valuable member of the board of directors of our general partner.

ITEM 11.Executive Compensation

As is commonly the case for many publicly traded limited partnerships, we have no employees. Under the terms of our partnership agreement, we are ultimately managed by our general partner. All of our employees, including our executive officers, are employees of USAC Management, a wholly owned subsidiary of our general partner.

Executive Compensation

We are an “emerging growth company” as defined under the Jumpstart Our Business Startups (JOBS) Act. As such, we are permitted to meet the disclosure requirements of Item 402 of Regulation S-K by providing the reduced disclosures required of a “smaller reporting company.”

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Executive Summary

This Executive Compensation disclosure provides an overview of the executive compensation program for our named executive officers identified below. Our general partner intends to provide our named executive officers with compensation that is significantly performance based. For the year ended December 31, 2016, our named executive officers ("NEOs") were:

- Eric D. Long, President and Chief Executive Officer;
- William G. Manias, Vice President and Chief Operating Officer; and
- Matthew C. Liuzzi, Vice President, Chief Financial Officer and Treasurer.

Summary Compensation Table

The following table sets forth certain information with respect to the compensation paid to our NEOs for the years ended December 31, 2016 and 2015.

Name and Principal Position	Year	Salary ($)	Bonus ($) (1)	Unit Awards ($) (2)	All Other Compensation ($)		Total ($)
Eric D. Long	2016	607,019	773,419	1,892,893	742,412	(3)	4,015,743
President and Chief Executive Officer	2015	588,962	885,000	1,500,000	279,917		3,253,879
William G. Manias	2016	411,538	416,353	1,069,430	380,616	(4)	2,277,937
Vice President and Chief Operating Officer	2015	399,596	450,000	725,000	95,866		1,670,462
Matthew C. Liuzzi	2016	362,885	381,399	852,693	306,589	(5)	1,903,566
Vice President, Chief Financial Officer and Treasurer	2015	312,247	325,500	586,500	85,351		1,309,598

(1) Represents the awards earned under annual cash incentive bonus program for the years ended December 31, 2016 and 2015, as applicable. For a discussion of the determination of the 2016 bonus amounts, see "—Annual Incentive Compensation for 2016" below.

(2) On February 11, 2016, each of our NEOs received an award of time-based and performance-based phantom units under our long-term incentive plan ("LTIP"). Each phantom unit is the economic equivalent of one common unit, although the performance-based awards could be settled at 200% of target levels in the event that the performance goals are satisfied at such levels. The phantom unit values reflect the grant date fair value of the awards calculated in accordance with the Financial Accounting Standards Board's ("FASB") Accounting Standard Codification ("ASC") Topic 718, disregarding the estimate of forfeitures. For a discussion of the assumptions utilized in determining the fair value of these awards, please see Note 9 to our consolidated financial statements. With respect to the performance-based awards, the value of the awards has been reflected at the probable outcome of performance conditions as of the grant date for accounting purposes. If the awards were to be reflected at maximum amounts, the year 2016 amounts reflected in the table above would be increased by the following amounts: Mr. Long, $434,412; Mr. Manias, $245,430; and Mr. Liuzzi, $195,693.

(3) Includes $692,357 of distribution equivalent rights ("DERs"), $18,000 of automobile allowance, $9,623 of club membership dues, $7,950 of employer contributions under the 401(k) plan, $3,572 of parking, $8,910 of personal administrative assistant support and $2,000 of personal tax support. Please see a description of the DERs under "—Discretionary Long-Term Equity Incentive Awards" below.

(4) Includes $370,958 of DERs, $7,255 of employer contributions under the 401(k) plan and $2,403 of parking.

(5) Includes $296,236 in DERs, $7,950 of employer contributions under the 401(k) plan and $2,403 of parking.

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Narrative Disclosure to Summary Compensation Table

Elements of the Compensation Program

Compensation for our NEOs consists primarily of the elements, and their corresponding objectives, identified in the following table.

Compensation Element	Primary Objective
Base salary	To recognize performance of job responsibilities and to attract and retain individuals with superior talent.
Annual incentive compensation	To promote near-term performance objectives and reward individual contributions to the achievement of those objectives.
Discretionary long-term equity incentive awards	To emphasize long-term performance objectives, encourage the maximization of unitholder value and retain key executives by providing an opportunity to participate in the ownership of our partnership.
Severance benefits	To encourage the continued attention and dedication of key individuals and to focus the attention of such key individuals when considering strategic alternatives.
Retirement savings (401(k)) plan	To provide an opportunity for tax-efficient savings.
Other elements of compensation and perquisites	To attract and retain talented executives in a cost-efficient manner by providing benefits with high perceived values at relatively low cost.

Base Compensation For 2016 and 2017

Base salaries for our NEOs have generally been set at a level deemed necessary to attract and retain individuals with superior talent. Base salary increases are determined based upon the job responsibilities, demonstrated proficiency and performance of the executive officers and market conditions, each as assessed by the board of directors of our general partner or the chief executive officer (for non-chief executive officer compensation) in conjunction with the compensation committee. No formulaic base salary increases are provided to the NEOs. For 2016 and 2017, in connection with determining base salaries for each of our NEOs, the board of directors of our general partner, compensation committee and chief executive officer worked with a compensation consultant to determine comparable salaries for our peer group, which we identified based on a review of companies in our industry with similar

characteristics.

Based upon the information provided by the compensation consultant with respect to a review of base salary information of companies within our peer group, the board of directors of our general partner has determined to target base salaries more directly in-line with our peer group. For 2016 and 2017, the board of directors of our general partner determined that base salary should be set at approximately the 50th percentile of the peer group. The 2016 and current 2017 base salaries for our NEOs, including for our Chief Executive Officer, are set forth in the following table:

Name and Principal Position	2016 Base Salary ($)	Current 2017 Base Salary ($)
Eric D. Long, President and Chief Executive Officer	607,700	625,931
William G. Manias, Vice President and Chief Operating Officer	412,000	424,360
Matthew C. Liuzzi, Vice President, Chief Financial Officer and Treasurer	365,000	375,950

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Annual Incentive Compensation For 2016

The board of directors of our general partner has approved the adoption of an Annual Cash Incentive Plan (the "Cash Plan"). Each of our NEOs is entitled to participate in the Cash Plan and their potential bonus is governed both by the Cash Plan and their employment agreement. The compensation committee acts as the administrator of the Cash Plan under the supervision of the full board of directors of our general partner, and has the discretion to amend, modify or terminate the Cash Plan at any time upon approval by the board of directors of our general partner. Although the Cash Plan uses both company and individual performance goals to determine bonus amounts, the Cash Plan is ultimately a discretionary annual bonus plan and awards are therefore reported in the "Bonus" column within the Summary Compensation Table above.

The board of directors of our general partner sets a target bonus amount (the "Target Bonus") for each NEO prior to or during the first quarter of the calendar year. For the year ended December 31, 2016, the Target Bonus for each NEO was $607,700 for Mr. Long, $329,600 for Mr. Manias and $273,750 for Mr. Liuzzi. The Target Bonus is generally subject to the satisfaction of both a partnership performance goal and an individual performance goal. For the year ended December 31, 2016 seventy-five percent (75%) of the Target Bonus was subject to our achievement of our budgeted distributable cash flow level ("DCF") for the year, as determined by our board of directors of our general partner. Payouts with respect to the portion of the bonus subject to DCF (the "DCF Bonus") generally do not occur unless we have satisfied the threshold set for DCF. For 2016, the board of directors of our general partner set the budget for DCF at $115.4 million. The threshold, target and maximum requirements for the DCF target for the year ended December 31, 2016, as well as the portion of the DCF Bonus that could become payable if performance was satisfied for the year, are set forth below:

Levels of DCF Bonus	DCF as a Percentage of Budgeted DCF for 2016	Percentage of DCF Bonus that would be Paid
Threshold	80%	50%
Target	100%	100%
Maximum	110%	200%

If DCF performance falls in between threshold and target, or between target and maximum, the amounts payable are adjusted ratably using straight line interpolation. If DCF is satisfied above maximum levels, the potential payment of the DCF Bonus is capped at the maximum level of 200%.

For the year ended December 31, 2016, the remaining twenty-five percent (25%) of the Target Bonus was subject to individual objectives specific to each eligible individual's role at USAC Management (the "Individual Bonus"). The individual objectives are agreed upon in advance between the NEO and his immediate supervisor (or, with respect to the chief executive officer, between the board of directors of our general partner and the chief executive officer) and such objectives address the key priorities for that NEO's position. They may include key operating objectives as well as personal development criteria. The Individual Bonus is subject to a maximum payout of 100% of the targeted Individual Bonus amount, although the board of directors of our general partner has discretion to pay out smaller amounts ranging from 0% to 100%, at their sole discretion, after analyzing the individual's personal performance for the year. In connection with the Individual Bonus for the year ended December 31, 2016, each of the NEOs met with their immediate supervisor (or, with respect to the chief executive officer, the board of directors of our general partner) to set individual objectives that reflected the responsibilities and priorities of their position.

For the year ended December 31, 2016, in the aggregate, the maximum amount payable with respect to a Target Bonus under the Plan is 175%, as the DCF Bonus is capped at 200% of target and the Individual Bonus is capped at 100% of target. Target Bonuses, if any, are paid within one week following delivery by our independent auditor of the audit of our financial statements for the year in which the Target Bonus relates, but in no case later than March 15 of the year following the year in which the Target Bonus relates. For the year ended December 31, 2016, DCF exceeded the target threshold by 2.6%, which resulted in the DCF portion of the Cash Plan (comprising seventy-five percent of the

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overall Bonus) being paid to each NEO at the rate of 126% for the DCF Bonus. With respect to the Individual Bonus portion of the overall Bonus, each NEO was determined by his immediate supervisor (which in the case of the chief executive officer is the board of directors of our general partner) to have satisfied his individual objectives and therefore was entitled to receive 100% of the Individual Bonus. The awards made pursuant to the Cash Plan with respect to the 2016 year were:

Eric D. Long	$ 773,419
William G. Manias	$ 416,353
Matthew C. Liuzzi	$ 381,399

Benefit Plans and Perquisites

We provide our executive officers, including our NEOs, with certain personal benefits and perquisites, which we do not consider to be a significant component of executive compensation but which we recognize are an important factor in attracting and retaining talented executives. Executive officers are eligible under the same plans as all other employees with respect to our medical, dental, vision, disability and life insurance plans and a defined contribution plan that is tax-qualified under Section 401(k) of the Internal Revenue Code and that we refer to as the 401(k) Plan. We also provide certain executive officers with an annual automobile allowance. We provide these supplemental benefits to our executive officers due to the relatively low cost of such benefits and the value they provide in assisting us in attracting and retaining talented executives. The value of personal benefits and perquisites we provide to each of our NEOs is set forth above in our "—Summary Compensation Table."

Discretionary Long-Term Equity Incentive Awards

The board of directors of our general partner has adopted an LTIP. The LTIP was designed to promote our interests, as well as the interests of our unitholders, by rewarding the officers, employees and directors of us, our subsidiaries and our general partner for delivering desired performance results, as well as by strengthening our and our general partner's ability to attract, retain and motivate qualified individuals to serve as officers, employees and directors. The LTIP provides for the grant, from time to time at the discretion of the board of directors of our general partner, of unit awards, restricted units, phantom units, unit options, unit appreciation rights, DERs and other unit-based awards, although in 2016, as well as in 2015, the board of directors of our general partner only granted phantom unit awards pursuant to the LTIP. The outstanding LTIP awards held by our NEOs are reflected in the table below.

During 2016 the board of directors of our general partner granted phantom unit awards to certain key employees, including our NEOs. With respect to our 2016 awards, twenty percent (20%) of the phantom unit award to each

individual is subject to a performance-based vesting formula and the remaining eighty percent (80%) of the phantom unit award is subject to time-based vesting restrictions. Phantom unit awards granted in 2015 to certain key employees, including our NEOs, were entirely subject to time-based vesting. With respect to the time-based phantom unit awards, the awards will vest in three equal annual installments, with the first installment vesting on the first anniversary of the date of grant. With respect to the performance-based phantom unit awards granted in 2016, the awards will vest based upon our level of total unitholder return ("TUR") relative to a group of peer companies over the period beginning December 31, 2015 and ending December 31, 2018. The peer group companies with respect to the 2016 performance-based phantom unit awards are the constituent companies in the Alerian Natural Gas MLP Index, as reported in the Alerian Capital Management or other relevant reporter. The performance-based phantom unit awards are granted at a "target" level, but will be eligible to vest from 0%-200% of the target level. Threshold levels (50% of target) are set at the 35th percentile of the constituent companies, target levels (100% of target) are set at the 50th percentile of the constituent companies, and maximum levels (200%) are set at the 90th percentile of the constituent companies. The awards will be adjusted ratably using straight line interpolation for TUR results between threshold and target and between target and maximum.

Each phantom unit granted to an employee, including the NEOs, is granted in tandem with a corresponding DER, which is paid quarterly on the distribution date from the grant date until the earlier of the vesting or the forfeiture of the related phantom units. With respect to the performance-based phantom units, the DERs will only be granted with respect to the target level number, and will not be adjusted up or down depending on the actual TUR results. The DERs entitle

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the recipient of the award to a payment equivalent to the amount of the per common unit distribution payable to common unitholders following the grant date of such DERs for each phantom unit granted in tandem with such rights.

Mr. Long was also granted Class B Units of USA Compression Holdings at the time we were acquired by USA Compression Holdings in 2010. Mr. Manias and Mr. Liuzzi were granted Class B Units of USA Compression Holdings at the time of their employment. The grants the NEOs received had time-based vesting requirements (which, for Mr. Long, were satisfied in full as of December 31, 2013) and are designed not only to compensate but also to motivate and retain the recipients by providing an opportunity for equity ownership by our NEOs. The grants to our NEOs also provide our NEOs with meaningful incentives to increase unitholder value over time. The Class B Units are profits interests that allow our NEOs to participate in the increase in value of USA Compression Holdings over and above an annual and cumulative preferred return hurdle. Available cash will be distributed to the USA Compression Holdings members at such times as determined by its board of managers, at which time the holders of Class B Units could receive distributions if the cash distributed reaches the required distribution hurdles. Distributions to the Class B Unit holders could also occur in connection with a sale or liquidation event of USA Compression Holdings. To date, our NEOs have not received distributions with respect to these awards.

Outstanding Equity Awards as of December 31, 2016

The following table provides information regarding the Class B Units in USA Compression Holdings held by the NEOs as of December 31, 2016. None of our NEOs held any option awards that were outstanding as of December 31, 2015 and 2016. Also reflected within the table are the outstanding phantom units that were granted to our NEOs from the LTIP during the years ended December 31, 2014, 2015 and 2016, respectively.

	Unit Awards					Equity Incentive Plan Awards	
Name	Number of Class B Units That Have Vested but Are Still Outstanding (#)(1)	Number of Class B Units That Are Unvested and Outstanding (#)(2)	Market Value of Class B Units That Have Not Vested ($)(3)	Number of Outstanding Phantom Units (Time-Based) (#)	Market Value of Outstanding Phantom Units ($) (7)	Number of Unearned Units That Have Not Vested (Performance-Based) (#) (8)	Market Value Of Unearned Units That Have Not Vested (Performance-Based) ($)(7)
Eric D. Long	481,250		—				
2014 Grant				12,631	(4) 218,516		
2015 Grant				50,352	(5) 871,090		

2016 Grant				201,726	(6) 3,489,860	100,862	1,744,913
William G. Manias	106,771	18,229	—				
2014 Grant				2,631	(4) 109,250		
2015 Grant				24,336	(5) 421,013		
2016 Grant				113,969	(6) 1,971,664	56,984	985,823
Matthew C. Liuzzi	57,292	5,208	—				
2014 Grant				3,571	(4) 61,778		
2015 Grant				19,687	(5) 340,585		
2016 Grant				90,871	(6) 1,572,068	45,436	786,043

(1) Represents the number of Class B Units in USA Compression Holdings that became vested but had not been settled as of December 31, 2016. These Class B Units vested 25% on the one-year anniversary of the date of grant and 1/36 monthly thereafter; provided that with respect to Mr. Long 50% of the then-unvested portion of Class B Units vested at the time of our initial public offering, which occurred on January 18, 2013.

(2) Represents the number of Class B Units in USA Compression Holdings that have not yet vested. The remainder of Mr. Manias' awards are scheduled to vest pro rata each month through July 15, 2017. The remainder of Mr. Liuzzi's awards are scheduled to vest pro rata each month through April 17, 2017.

(3) As described under the heading "—Discretionary Long-Term Equity Incentive Awards," the Class B Units are intended to allow recipients to receive a percentage of profits generated by USA Compression Holdings over and above certain return hurdles. The Class B Units had no recognizable value as of December 31, 2016 and the holders of the Class B Units had not received any distributions with respect to those awards during the 2016 year.

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(4) Represents the number of phantom units issued on February 20, 2014 pursuant to the LTIP that have not vested as of December 31, 2016. Each phantom unit is the economic equivalent of one common unit. The phantom units are scheduled to vest in three equal annual installments on each subsequent February 15th with the first installment vesting on February 15, 2015. In the event of cessation of the NEO's service for any reason, all phantom units that have not vested prior to or in connection with such cessation of service shall automatically be forfeited.

(5) Represents the number of phantom units issued on February 19, 2015 pursuant to the LTIP that had not vested as of December 31, 2016. Each phantom unit is the economic equivalent of one common unit. The phantom units are scheduled to vest in three equal annual installments on each subsequent February 15th with the first installment vesting on February 15, 2016. In the event of cessation of the NEO's service for any reason, all phantom units that have not vested prior to or in connection with such cessation of service shall automatically be forfeited.

(6) Represents the number of time-based phantom units issued on February 11, 2016 pursuant to the LTIP that had not vested as of December 31, 2016. Each phantom unit is the economic equivalent of one common unit. The phantom units are scheduled to vest in three equal annual installments on each subsequent February 15th with the first installment vesting on February 15, 2017. In the event of cessation of the NEO's service for any reason, all phantom units that have not vested prior to or in connection with such cessation of service shall automatically be forfeited.

(7) Market value is calculated using the value of $17.30, which was the closing price of our common units on December 30, 2016 (as December 31, 2016 was not a trading day).

(8) Represents the number of performance-based phantom units granted on February 11, 2016 pursuant to the LTIP that had not vested as of December 31, 2016. The number of performance-based phantom units was determined by calculating the level of TUR performance that would have been achieved as of December 31, 2016 with respect to our constituent companies, and reflecting the next highest level of achievement within the table above, which was the maximum level. The performance period for these awards will end on December 31, 2018 and will vest, if at all, based upon the level of TUR performance achieved at that time. Events that could result in accelerated vesting are described below under the heading "Severance and Change in Control Arrangements."

Severance and Change in Control Arrangements

Our NEOs are entitled to severance payments and benefits upon certain terminations of employment and, in certain cases, in connection with a change in control (as defined below) of USA Compression Holdings.

Each NEO currently has an employment agreement with USAC Management that provides for severance benefits upon a termination of employment. On January 1, 2013, we entered into the services agreement with USAC Management, pursuant to which USAC Management provides to us and our general partner management, administrative and operating services and personnel to manage and operate our business. Pursuant to the services agreement, we will reimburse USAC Management for the allocable expenses for the services performed, including the

salary, bonus, cash incentive compensation and other amounts paid to our NEOs. See Part III, Item 13 (“Certain Relationships and Related Transactions, and Director Independence”).

Severance Arrangements

Each NEO’s employment agreement had an initial term that has been extended on a year-to-year basis and will be extended automatically for successive twelve-month periods thereafter unless either party delivers written notice to the other within ninety days prior to the expiration of the then-current employment term. Upon termination of an NEO’s employment for any reason, all earned, unpaid annual base salary and vacation time (and, with respect to the chief executive officer, accrued, unused sick time off) shall be paid to the NEO within thirty (30) days of the date of the NEO’s termination of employment. Upon termination of an NEO’s employment either by us for convenience or due to the NEO’s resignation for good reason, subject to the timely execution of a general release of claims, the NEO is entitled to receive (i) an amount equal to one times his annual base salary (plus, in the case of Mr. Long, an amount equal to one times his target annual bonus), payable in equal semi-monthly installments over one year following termination (the “Severance Period”) (or, if such termination occurs within two years following a change in control, in a lump sum within thirty days following the termination of employment), subject to acceleration upon the NEO’s death during the Severance Period, and (ii) continued coverage for twenty-four (24) months (or, with respect to Mr. Long, thirty (30) months) under our group medical plan in which the executive and any of his dependents were participating immediately

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prior to his termination. Continued coverage under our group medical plan is subsidized for the first twelve (12) months following termination, after which time continued coverage shall be provided at the NEO's sole expense (except with respect to Mr. Long, who is entitled to reimbursement by us to the extent the cost of such coverage exceeds $1,200 per month) for the remainder of the applicable period. Additionally, upon a termination of an NEO's employment by us for convenience, by the NEO for good reason, or due to the NEO's death or disability, the NEO is entitled to receive (i) an amount equal to one times his annual bonus (up to his target annual bonus) for the immediately preceding year and (ii) a pro-rata portion of any earned annual bonus for the year in which termination occurs. During employment and for two years following termination, each NEO's employment agreement prohibits him from competing with our business.

As used in the NEOs' employment agreements, a termination for "convenience" means an involuntary termination for any reason, including a failure to renew the employment agreement at the end of an initial term or any renewal term, other than a termination for "cause." "Cause" is defined in the NEOs' employment agreements to mean (i) any material breach of the employment agreement or the Holdings Operating Agreement, by the executive, (ii) the executive's breach of any applicable duties of loyalty to us or any of our affiliates, gross negligence or misconduct, or a significant act or acts of personal dishonesty or deceit, taken by the executive, in the performance of the duties and services required of the executive that has a material adverse effect on us or any of our affiliates, (iii) conviction or indictment of the executive of, or a plea of nolo contendere by the executive to, a felony, (iv) the executive's willful and continued failure or refusal to perform substantially the executive's material obligations pursuant to the employment agreement or the Holdings Operating Agreement or follow any lawful and reasonable directive from the board of managers of USA Compression Holdings (regarding Mr. Long) or the board of directors of our general partner (regarding Mr. Manias and Mr. Liuzzi) or, as applicable, the chief executive officer, other than as a result of the executive's incapacity, or (v) a pattern of illegal conduct by the executive that is materially injurious to us or any of our affiliates or our or their reputation.

"Good reason" is defined in the NEOs' employment agreements to mean (i) a material breach by us of the employment agreement, the Holdings Operating Agreement, or any other material agreement with the executive, (ii) any failure by us to pay to the executive the amounts or benefits to which he is entitled, other than an isolated and inadvertent failure not committed in bad faith, (iii) a material reduction in the executive's duties, reporting relationships or responsibilities, (iv) a material reduction by us in the facilities or perquisites available to the executive or in the executive's base salary, other than a reduction that is generally applicable to all similarly situated employees, or (v) the relocation of the geographic location of the executive's current principal place of employment by more than fifty miles from the location of the executive's principal place of employment. With respect to Mr. Long's employment agreement, "good reason" also means the failure to appoint and maintain Mr. Long in the office of President and Chief Executive Officer.

In the event of cessation of the NEO's service for any reason, all phantom units that have not vested prior to or in connection with such cessation of service shall automatically be forfeited. With respect to the time-based awards for Mr. Manias and Mr. Liuzzi, the awards will receive accelerated vesting in the event that that the holder is terminated without cause or for good reason (as each term is defined above with respect to the employment agreements) in connection with a change in control event. With respect to the time-based awards for Mr. Long, the award will receive accelerated vesting in connection with a change in control event regardless of whether Mr. Long's service is terminated in connection with such change in control. All performance-based phantom unit awards will receive

accelerated vesting at target levels in connection with a change in control event (subject to the discretion of the compensation committee to vest a greater portion).

Each of the Class B Units held by the NEOs would be forfeited for no consideration if the NEO was terminated for cause. A termination for “Cause” under the USA Compression Holdings limited liability company agreement is defined substantially the same as the term used within the employment agreements described above. In the event that the NEO’s employment is terminated for any reason, however, USA Compression Holdings (or its nominee) shall have the right, but not the obligation, to repurchase any vested Class B Units held by the terminated NEO for then-current fair market value or other agreed value.

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Change in Control Benefits

We generally have double-trigger change in control benefits for our outstanding LTIP awards, although in 2016 we granted performance-based phantom unit awards that could become vested upon a change in control. If a change in control occurs, and our NEOs are also terminated without cause or for good reason (each term as defined in the NEO's employment agreement) in connection with that change in control event, the current time-based LTIP phantom units would become fully vested. One exception to this practice is with respect to our CEO, who would receive immediate vesting of any outstanding time-based phantom units upon the change in control event. The performance-based phantom units granted during the 2016 year will become eligible to vest at target levels in the event of a change in control. In addition, a portion (subject to the discretion of the compensation committee) of each LTIP award granted to our NEOs during the year ending December 31, 2017 will immediately vest immediately prior to the change in control event.

A "Change in Control" is generally defined within the LTIP as the occurrence of one of the following events: (i) any person or group, other than our general partner, Riverstone Holdings LLC or an affiliate of our general partner or Riverstone Holdings LLC, shall become the beneficial owner, by way of merger, consolidation, recapitalization, reorganization or otherwise, of 50% or more of the combined voting power of our equity interests or the equity interests of our general partner; (ii) our shareholders approve, in one or a series of transactions, a plan of complete liquidation; (iii) the sale or other disposition by either us or our general partner of all or substantially all of its assets in one or more transactions to any person other than to us, our general partner, Riverstone Holdings LLC or an affiliate of us, our general partner or Riverstone Holdings LLC; (iv) a transaction resulting in a person other than our general partner, Riverstone Holdings LLC or an affiliate of our general partner or Riverstone Holdings LLC being our sole general partner. However, if an LTIP award is subject to section 409A of the Internal Revenue Code, a "Change in Control" will be defined in accordance with section 409A of the Internal Revenue Code and the regulations promulgated thereunder.

Director Compensation

For the year ended December 31, 2016, Mr. Long, our only NEO who also served as a director, did not receive additional compensation for his service as a director. Mr. Long's compensation as an executive is reflected in the Summary Compensation Table above. Only the independent members of the board of directors of our general partner receive compensation for their service as directors.

The following table shows the total compensation earned by each independent director during 2016.

Name	Fees Earned or Paid in Cash ($)	Unit Awards ($) (1)	All Other Compensation ($) (2)	Total ($)
John D. Chandler	128,000	75,000	8,217	211,217
Robert F. End	140,000	75,000	8,217	223,217
Forrest E. Wylie	113,000 (3)	75,000	16,437	204,437

(1) Represents the grant date fair value of our phantom units, calculated in accordance with ASC 718. For a detailed discussion of the assumptions utilized in coming to these values, please see Note 9 to our consolidated financial statements. As of December 31, 2016, the independent members of the board of directors of our general partner held the following number of outstanding equity awards under the LTIP: Mr. Chandler, 9,090 phantom units; Mr. End, 9,090 phantom units; and Mr. Wylie, 18,181 phantom units.

(2) Amounts in this column reflect the value of DERs, received by the directors with respect to their outstanding phantom unit awards.

(3) Mr. Wylie elected to receive his annual cash retainer of $75,000 in phantom units that will vest in full on February 15, 2017.

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Officers, employees or paid consultants or advisors of us or our general partner or its affiliates who also serve as directors do not receive additional compensation for their service as directors. Our directors who are not officers, employees or paid consultants or advisors of us or our general partner or its affiliates receive cash and equity based compensation for their services as directors. Our director compensation program consists of the following and will be subject to revision by the board of directors of our general partner from time to time:

- an annual cash retainer of $75,000,
- an additional annual retainer of $15,000 for service as the chair of any standing committee,
- meeting attendance fees of $2,000 per meeting attended, and
- an annual equity based award in the form of phantom units that will be granted under the LTIP, having a value as of the grant date of $75,000. Phantom unit awards are expected to be subject to vesting conditions (which, for the 2016 phantom unit grants was a one year vesting period). DERs will be paid either on a current or deferred basis, in each case as will be determined at the time of grant of the awards; the 2016 phantom unit awards provided for deferred DERs.

Directors will also receive reimbursement for out-of-pocket expenses associated with attending such board or committee meetings and director and officer liability insurance coverage. Each director will be fully indemnified by us for actions associated with being a director to the fullest extent permitted under Delaware law.

ITEM 12.Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters

Security Ownership of Certain Beneficial Owners and Management

The following table sets forth the beneficial ownership of our units as of February 9, 2017 held by:

- each person who beneficially owns 5% or more of our outstanding units;
- all of the directors of USA Compression GP, LLC;

- each named executive officer of USA Compression GP, LLC; and

- all directors and officers of USA Compression GP, LLC as a group.

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Except as indicated by footnote, the persons named in the table below have sole voting and investment power with respect to all units shown as beneficially owned by them and their address is 100 Congress Avenue, Suite 450, Austin, Texas 78701.

Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned	
USA Compression Holdings (1)	23,929,262	39.4	%
Argonaut (2)	7,715,948	12.7	%
Oppenheimer Funds, Inc. (3)	6,161,618	10.2	%
Eric D. Long (4)	292,486	*	
William G. Manias (5)	114,344	*	
Matthew C. Liuzzi (6)	76,113	*	
John D. Chandler (7)	16,741	*	
Jim H. Derryberry	—	—	
William H. Shea, Jr.	—	—	
Robert F. End (8)	29,644	*	
Olivia C. Wassenaar	—	—	
Forrest E. Wylie (9)	45,102	*	
All directors and executive officers as a group (12 persons) (10)	657,114	1.1	%

*Less than 1%.

(1) Eric D. Long, Matthew C. Liuzzi, William G. Manias, and David A. Smith, each of whom are executive officers of our general partner, Aladdin Partners, L.P., a limited partnership affiliated with Mr. Long, and R/C IV USACP Holdings, L.P. (“R/C Holdings”), own equity interests in USA Compression Holdings. USA Compression Holdings is managed by a three person board of managers consisting of Mr. Long, Mr. Derryberry and Ms. Wassenaar. The board of managers exercises investment discretion and control over the units held by USA Compression Holdings.

R/C Holdings is the record holder of approximately 97.6% of the limited liability company interests of USA Compression Holdings and is entitled to elect a majority of the members of the board of managers of USA Compression Holdings. R/C Holdings is an investment partnership affiliated with Riverstone/Carlyle Global Energy and Power Fund IV, L.P. (“R/C IV”). Management and control of R/C Holdings is vested in its general partner, which is in turn managed and controlled by its general partner, R/C Energy GP IV, LLC. The principal business address of R/C Energy GP IV, LLC is 712 Fifth Avenue, 51st Floor, New York, New York 10019.

Mr. Long, Mr. Derryberry and Ms. Wassenaar, each of whom is a member of the board of managers of USA Compression Holdings and a member of the board of directors of our general partner, each disclaims beneficial ownership of the units owned by USA Compression Holdings.

(2) Argonaut has sole voting and dispositive power of 7,715,948 common units. The principal business address of Argonaut is 6733 South Yale Avenue, Tulsa, Oklahoma 74136.

(3) Oppenheimer Funds, Inc. has the shared power to vote or to direct the vote, and the shared power to dispose or to direct the disposition of, 6,161,618 common units, including 6,048,263 common units held by Oppenheimer SteelPath MLP Income Fund, based on Amendment No. 7 to Schedule 13G filed on February 9, 2017 with the SEC. The principal business address of Oppenheimer Funds, Inc. is Two World Financial Center, 225 Liberty Street, New York, New York 10281, and the principal business address of Oppenheimer SteelPath MLP Income Fund is 6803 South Tucson Way, Centennial, Colorado 80112.

(4) Includes 132,423 common units held directly by Mr. Long, 7,592 common units held by Aladdin Partners, L.P., a limited partnership affiliated with Mr. Long, 45,248 common units held by certain trusts of which Mr. Long is the trustee, 2,174 common units held by Mr. Long's spouse and 105,049 common units that Mr. Long has the right to acquire within 60 days upon the vesting and/or settlement of his phantom units, subject to compensation committee discretion. Mr. Long disclaims any beneficial ownership of the units held by Mr. Long's spouse, except to the extent of his pecuniary interest therein.

(5) Includes 52,789 common units that Mr. Manias has the right to acquire within 60 days upon the vesting and/or settlement of his phantom units, subject to compensation committee discretion.

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(6) Includes 43,706 common units that Mr. Liuzzi has the right to acquire within 60 days upon the vesting and/or settlement of his phantom units, subject to compensation committee discretion.

(7) Includes 9,090 common units that Mr. Chandler has the right to acquire within 60 days upon the vesting and/or settlement of his phantom units.

(8) Includes 9,090 common units that Mr. End has the right to acquire within 60 days upon the vesting and/or settlement of his phantom units.

(9) Includes 18,181 common units that Mr. Wylie has the right to acquire within 60 days upon the vesting and/or settlement of his phantom units.

(10) Includes 285,982 common units that certain of our directors and executive officers have the right to receive within 60 days upon the vesting and/or settlement of phantom units held by such directors and executive officers.

Securities Authorized for Issuance Under Equity Compensation Plans

In connection with the consummation of our initial public offering on January 18, 2013, the board of directors of our general partner adopted the LTIP. The following table provides certain information with respect to this plan as of December 31, 2016:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plan (excluding securities reflected in the first column)	
Equity compensation plans approved by security holders	—	N/A	—	
Equity compensation plans not approved by security holders	1,241,368	N/A	—	(1)

(1) As of December 31, 2016, the number of common units that may be delivered pursuant to awards under the LTIP was 1,028,094 common units before giving effect to any outstanding awards. Awards that are forfeited, cancelled, paid or otherwise terminate or expire without the actual delivery of units will be available for delivery pursuant to other awards. Currently, only phantom unit awards are outstanding under the LTIP. Pursuant to the terms the

LTIP, each phantom unit award is the economic equivalent of one common unit and may be settled in cash or common units at the discretion of the board of directors of our general partner or a committee thereof. Any phantom unit settled in cash will not result in the actual delivery of a common unit.

For more information about our LTIP, please see Note 9 to our consolidated financial statements.

ITEM 13.Certain Relationships and Related Transactions, and Director Independence

Certain Relationships And Related Party Transactions

Services Agreement

In connection with our formation and initial public offering, we and other parties have entered into the following agreements. These agreements were not the result of arm's length negotiations, and they, or any of the transactions that they provide for, may not be effected on terms as favorable to the parties to these agreements as could have been obtained from unaffiliated third parties.

We entered into a services agreement with USAC Management, effective on January 1, 2013, pursuant to which USAC Management provides to us and our general partner management, administrative and operating services and personnel to manage and operate our business. We or one of our subsidiaries pays USAC Management for the allocable expenses it incurs in its performance under the services agreement. These expenses include, among other things, salary,

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bonus, cash incentive compensation and other amounts paid to persons who perform services for us or on our behalf and other expenses allocated by USAC Management to us. USAC Management has substantial discretion to determine in good faith which expenses to incur on our behalf and what portion to allocate to us.

The services agreement has an initial term of five years, at which point it automatically renews for additional one year terms. The services agreement may be terminated at any time by (i) the board of directors of our general partner upon 120 days' written notice for any reason in its sole discretion or (ii) USAC Management upon 120 days' written notice if: (a) we or our general partner experience a change of control; (b) we or our general partner breach the terms of the services agreement in any material respect following 30 days' written notice detailing the breach (which breach remains uncured after such period); (c) a receiver is appointed for all or substantially all of our or our general partner's property or an order is made to wind up our or our general partner's business; (d) a final judgment, order or decree that materially and adversely affects the ability of us or our general partner to perform under the services agreement is obtained or entered against us or our general partner, and such judgment, order or decree is not vacated, discharged or stayed; or (e) certain events of bankruptcy, insolvency or reorganization of us or our general partner occur. USAC Management will not be liable to us for their performance of, or failure to perform, services under the services agreement unless its acts or omissions constitute gross negligence or willful misconduct.

Other Related Party Transactions

We provide compression services to entities affiliated with Riverstone/Carlyle Global Energy and Power Fund IV, L.P. ("Riverstone"), which owns a majority of the membership interests in USA Compression Holdings. As of December 31, 2016, USA Compression Holdings owned and controlled our General Partner and owned 39.4% of our limited partner interests. We recognized approximately $0.4 million in revenue from compression services from such affiliated entities for the year ended December 31, 2016. We recognized no revenue from such controlled entities during the year ended December 31, 2015. We may provide compression services to entities affiliated with Riverstone in the future, and any significant transactions will be disclosed.

Procedures for Review, Approval and Ratification of Related Person Transactions

The board of directors of our general partner adopted a code of business conduct and ethics in connection with the closing of our initial public offering that provides that the board of directors of our general partner or its authorized committee will periodically review all related person transactions that are required to be disclosed under SEC rules and, when appropriate, initially authorize or ratify all such transactions. If the board of directors of our general partner or its authorized committee considers ratification of a related person transaction and determines not to so ratify, the code of business conduct and ethics provides that our management will make all reasonable efforts to cancel or annul the transaction.

The code of business conduct and ethics provides that, in determining whether or not to recommend the initial approval or ratification of a related person transaction, the board of directors of our general partner or its authorized committee should consider all of the relevant facts and circumstances available, including (if applicable) but not limited to: (i) whether there is an appropriate business justification for the transaction; (ii) the benefits that accrue to us as a result of the transaction; (iii) the terms available to unrelated third parties entering into similar transactions; (iv) the impact of the transaction on a director's independence (in the event the related person is a director, an immediate family member of a director or an entity in which a director or an immediately family member of a director is a partner, shareholder, member or executive officer); (v) the availability of other sources for comparable products or services; (vi) whether it is a single transaction or a series of ongoing, related transactions; and (vii) whether entering into the transaction would be consistent with the code of business conduct and ethics.

The code of business conduct and ethics described above was adopted in connection with the closing of our initial public offering, and as a result the transaction described above was not reviewed under such policy. The transaction described above was not approved by an independent committee of our board of directors of our general partner and the terms were determined by negotiation among the parties.

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Conflicts of Interest

Conflicts of interest exist and may arise in the future as a result of the relationships between our general partner and its affiliates, including USA Compression Holdings, on the one hand, and our partnership and our limited partners, on the other hand. The directors and officers of our general partner have fiduciary duties to manage our general partner in a manner beneficial to its owners. At the same time, our general partner has a fiduciary duty to manage our partnership in a manner beneficial to us and our unitholders.

Whenever a conflict arises between our general partner or its affiliates, on the one hand, and us and our limited partners, on the other hand, our general partner will resolve that conflict. Our partnership agreement contains provisions that modify and limit our general partner's fiduciary duties to our unitholders. Our partnership agreement also restricts the remedies available to our unitholders for actions taken by our general partner that, without those limitations, might constitute breaches of its fiduciary duty.

Our general partner will not be in breach of its obligations under our partnership agreement or its fiduciary duties to us or our unitholders if the resolution of the conflict is:

- approved by the conflicts committee of our general partner, although our general partner is not obligated to seek such approval;

- approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner or any of its affiliates;

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

- 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.

Our general partner may, but is not required to, seek the approval of such resolution from the conflicts committee of its board of directors. In connection with a situation involving a conflict of interest, any determination by our general partner involving the resolution of the conflict of interest must be made in good faith, provided that, if our general partner does not seek approval from the conflicts committee and its board of directors determines that the resolution or course of action taken with respect to the conflict of interest satisfies either of the standards set forth in the third and fourth bullet points above, then it will conclusively be deemed that, in making its decision, the board of directors acted in good faith. Unless the resolution of a conflict is specifically provided for in our partnership agreement, our general partner or the conflicts committee may consider any factors that it determines in good faith to be appropriate when resolving a conflict. When our partnership agreement provides that someone act in good faith, it requires that person

to reasonably believe he is acting in the best interests of the partnership.

Director Independence

Please see Part III, Item 10 (“Directors, Executive Officers and Corporate Governance—Board of Directors”) for a discussion of director independence matters.

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ITEM 14.Principal Accountant Fees and Services

The following table presents fees for professional services rendered by our independent registered public accounting firm, KPMG LLP during the years ended December 31, 2016 and 2015:

	Year Ended December 31,	
	2016	2015
	(in millions)	
Audit Fees (1)	$ 0.6	$ 0.6
Audit-Related Fees	—	—
Tax Fees	—	—
All Other Fees	—	—
Total	$ 0.6	$ 0.6

(1) Expenditures classified as “Audit Fees” above were billed to USA Compression Partners, LP and include the audits of our annual financial statements, work related to the registration statements, reviews of our quarterly financial statements, and fees associated with comfort letters and consents related to equity offerings and registration statements.

Our audit committee has adopted an audit committee charter, which is available on our website and which requires the audit committee to pre-approve all audit and non-audit services to be provided by our independent registered public accounting firm. The audit committee does not delegate its pre-approval responsibilities to management or to an individual member of the audit committee.

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PART IV

ITEM 15.Exhibits and Financial Statement Schedules

(a) Documents filed as a part of this report.

1. Financial Statements. See “Index to Consolidated Financial Statements” set forth on Page F-1.

2. Financial Statement Schedule

All other schedules have been omitted because they are not required under the relevant instructions.

3. Exhibits

The following documents are filed as exhibits to this report:

Exhibit Number	Description
3.1	Certificate of Limited Partnership of USA Compression Partners, LP (incorporated by reference to Exhibit 3.1 to Amendment No. 3 of the Partnership’s registration statement on Form S-1 (Registration No. 333-174803) filed on December 21, 2011)
3.2	First Amended and Restated Agreement of Limited Partnership of USA Compression Partners, LP (incorporated by reference to Exhibit 3.1 to the Partnership’s Current Report on Form 8-K (File No. 001-35779) filed on January 18, 2013)
4.1	Registration Rights Agreement dated August 30, 2013 (incorporated by reference to Exhibit 4.1 to the Partnership’s Current Report on Form 8-K (File No. 001-35779) filed on September 5, 2013)
10.1	Fifth Amended and Restated Credit Agreement dated as of December 13, 2013, by and among USA Compression Partners, LP, USAC OpCo 2, LLC and USAC Leasing 2, LLC, as guarantors, USA Compression Partners, LLC and USAC Leasing, LLC, as borrowers, the lenders party thereto from time to time, JPMorgan Chase Bank, N.A., as agent and LC issuer, J.P. Morgan

	Securities LLC, as lead arranger and sole book runner, Wells Fargo Bank, N.A., as documentation agent, and Regions Bank, as syndication agent (incorporated by reference to Exhibit 10.1 to the Partnership's Current Report on Form 8-K (File No. 001-35779) filed on December 17, 2013)
10.2	Letter Agreement by and among USA Compression Partners, LLC, USAC Leasing, LLC, USA Compression Partners, LP, USAC Leasing 2, LLC, USAC OpCo 2, LLC, the Lenders party thereto and JPMorgan Chase Bank, N.A., in its capacity as administrative agent for the Lenders, dated as of June 30, 2014 (incorporated by reference to Exhibit 10.1 to the Partnership's Current Report on Form 8-K (File No. 001-35779) filed on July 3, 2014)
10.3	Second Amendment to the Fifth Amended and Restated Credit Agreement, dated as of January 6, 2015, by and among USA Compression Partners, LP, as guarantor, USA Compression Partners, LLC, USAC Leasing, LLC, USAC OpCo 2, LLC and USAC Leasing 2, LLC, as borrowers, the lenders party thereto and JPMorgan Chase Bank, N.A., as agent and LC issuer (incorporated by reference to Exhibit 10.1 to the Partnership's Current Report on Form 8-K (File No. 001-35779) filed on January 9, 2015)
10.4	Third Amendment to the Fifth Amended and Restated Credit Agreement, dated as of March 18, 2016, by and among USA Compression Partners, LP, as guarantor, USA Compression Partners, LLC, USAC Leasing, LLC, USAC OpCo2, LLC and USAC Leasing 2, LLC, as borrowers, the lenders party thereto and JP Morgan Chase Bank, N.A., as agent and LC issuer (incorporated by reference to Exhibit 10.1 to the Partnership's Current Report on Form 8-K (File No. 001-35779) filed on March 21, 2016)
10.5†	Long-Term Incentive Plan of USA Compression Partners, LP (incorporated by reference to Exhibit 10.1 to the Partnership's Current Report on Form 8-K (File No. 001-35779) filed on January 18, 2013)

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10.6†	Employment Agreement, dated December 23, 2010, between USA Compression Partners, LLC and Eric D. Long (incorporated by reference to Exhibit 10.5 to Amendment No. 4 of the Partnership's registration statement on Form S-1 (Registration No. 333-174803) filed on February 13, 2012)
10.7†	Employment Agreement, dated April 17, 2013, between USA Compression Management Services, LLC and Matthew C. Liuzzi (incorporated by reference to Exhibit 10.1 to the Partnership's Current Report on Form 8-K (File No. 001-35779) filed on January 15, 2015)
10.8†	Employment Agreement, dated July 15, 2013, between USA Compression Management Services, LLC and William G. Manias (incorporated by reference to Exhibit 10.7 to the Partnership's Annual Report on Form 10-K for the year ended December 31, 2015 (File No. 001-35779) filed on February 11, 2016)
10.9	Services Agreement, dated effective January 1, 2013, by and among USA Compression Partners, LP, USA Compression GP, LLC and USA Compression Management Services, LLC (incorporated by reference to Exhibit 10.11 to Amendment No. 10 of the Partnership's registration statement on Form S-1 (Registration No. 333-174803) filed on January 7, 2013)
10.10†	USA Compression Partners, LP 2013 Long-Term Incentive Plan—Form of Director Phantom Unit Agreement (incorporated by reference to Exhibit 10.8 to the Partnership's Annual Report on Form 10-K for the year ended December 31, 2012 (File No. 001-35779) filed on March 28, 2013)
10.11†	USA Compression Partners, LP 2013 Long-Term Incentive Plan—Form of Employee Phantom Unit Agreement (incorporated by reference to Exhibit 10.10 to the Partnership's Annual Report on Form 10-K for the year ended December 31, 2013 (File No. 001-35779) filed on February 20, 2014)
10.12†	USA Compression Partners, LP 2013 Long-Term Incentive Plan—Form of Director Phantom Unit Agreement (in lieu of Annual Cash Retainer) (incorporated by reference to Exhibit 10.10 to the Partnership's Annual Report on Form 10-K for the year ended December 31, 2012 (File No. 001-35779) filed on March 28, 2013)
10.13†	USAC Compression Partners, LP Annual Cash Incentive Program (incorporated by reference to Exhibit 10.12 to the Partnership's Annual Report on Form 10-K for the year ended December 31, 2013 (File No. 001-35779) filed on February 20, 2014)
10.14†	USA Compression Partners, LP 2013 Long-Term Incentive Plan—Form of Employee Phantom Unit Agreement (with updated performance metrics) (incorporated by reference to Exhibit 10.13 to the Partnership's Annual Report on Form 10-K for the year ended December 31, 2015 (File No. 001-35779) filed on February 11, 2016)
21.1*	List of subsidiaries of USA Compression Partners, LP
23.1*	Consent of KPMG LLP
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934

31.2*	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934
32.1#	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2#	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101.INS*	XBRL Instance Document
101.SCH*	XBRL Extension Schema Document
101.CAL*	XBRL Calculation Linkbase Document

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101.DEF*	XBRL Definition Linkbase Document
101.LAB*	XBRL Label Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document

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*Filed Herewith.

#Furnished herewith; not considered to be “filed” for the purposes of Section 18 of the Securities Exchange Act of 1934 or otherwise subject to the liabilities of that section.

†Management contract or compensatory plan or arrangement.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

USA COMPRESSION PARTNERS, LP

By: USA Compression GP, LLC,
its General Partner

By: /s/ Eric D. Long
Eric D. Long
President and Chief Executive Officer
(Principal Executive Officer)

Date: February 13, 2017

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on February 13, 2017.

Name	Title
/s/ Eric D. Long Eric D. Long	President and Chief Executive Officer and Director (Principal Executive Officer)
/s/ Matthew C. Liuzzi Matthew C. Liuzzi	Vice President, Chief Financial Officer and Treasurer (Principal Financial and Accounting Officer)
/s/ John D. Chandler John D. Chandler	Director
/s/ Jim H. Derryberry Jim H. Derryberry	Director
/s/ Robert F. End Robert F. End	Director
/s/ William H. Shea, Jr.	

William H. Shea, Jr.	Director
/s/ Olivia C. Wassenaar Olivia C. Wassenaar	Director
/s/ Forrest E. Wylie Forrest E. Wylie	Director

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Report of Independent Registered Public Accounting Firm

The Partners

USA Compression Partners, LP:

We have audited the accompanying consolidated balance sheets of USA Compression Partners, LP (a Delaware limited partnership) and subsidiaries as of December 31, 2016 and 2015, and the related consolidated statements of operations, changes in partners' capital, and cash flows for each of the years in the three year period ended December 31, 2016. These consolidated financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of USA Compression Partners, LP and subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the years in the three year period ended December 31, 2016, in conformity with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Dallas, Texas

February 13, 2017

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USA COMPRESSION PARTNERS, LP

Consolidated Balance Sheets

(in thousands, except for unit amounts)

	December 31, 2016	2015
Assets		
Current assets:		
Cash and cash equivalents	$ 65	$ 7
Accounts receivable, net:		
Trade, net	32,237	28,465
Other	9,028	3,023
Inventory, net	29,556	18,872
Prepaid expenses	2,083	2,600
Total current assets	72,969	52,967
Property and equipment, net	1,267,574	1,318,043
Installment receivable	14,079	17,275
Identifiable intangible assets, net	75,189	78,773
Goodwill	35,866	35,866
Other assets	6,735	6,847
Total assets	$ 1,472,412	$ 1,509,771
Liabilities and Partners' Capital		
Current liabilities:		
Accounts payable	$ 13,148	$ 23,840
Accrued liabilities	26,572	20,582
Deferred revenue	16,691	17,000
Total current liabilities	56,411	61,422
Long-term debt	685,371	729,187
Other liabilities	1,113	874
Partners' capital:		
Limited partner interest:		
Common units, 60,689,110 and 38,556,245 units issued and outstanding, respectively	721,080	557,583
Subordinated units, 0 and 14,048,588 units issued and outstanding, respectively	—	150,787
General partner interest	8,437	9,918
Total partners' capital	729,517	718,288
Total liabilities and partners' capital	$ 1,472,412	$ 1,509,771

See accompanying notes to consolidated financial statements.

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USA COMPRESSION PARTNERS, LP

Consolidated Statements of Operations

(in thousands, except per unit amounts)

	Year Ended December 31,		
	2016	2015	2014
Revenues:			
Contract operations	$ 246,950	$ 263,816	$ 217,361
Parts and service	18,971	6,729	4,148
Total revenues	265,921	270,545	221,509
Costs and expenses:			
Cost of operations, exclusive of depreciation and amortization	88,161	81,539	74,035
Selling, general and administrative	44,483	40,950	38,718
Depreciation and amortization	92,337	85,238	71,156
Loss (gain) on sale of assets	772	(1,040)	(2,233)
Impairment of compression equipment	5,760	27,274	2,266
Impairment of goodwill	—	172,189	—
Total costs and expenses	231,513	406,150	183,942
Operating income (loss)	34,408	(135,605)	37,567
Other income (expense):			
Interest expense, net	(21,087)	(17,605)	(12,529)
Other	35	22	11
Total other expense	(21,052)	(17,583)	(12,518)
Net income (loss) before income tax expense	13,356	(153,188)	25,049
Income tax expense	421	1,085	103
Net income (loss)	$ 12,935	$ (154,273)	$ 24,946
Net income (loss) allocated to:			
General partner’s interest in net income (loss)	$ 1,364	$ (1,477)	$ 760
Limited partners’ interest in net income (loss):			
Common units	$ 14,282	$ (107,513)	$ 16,811
Subordinated units	$ (2,711)	$ (45,283)	$ 7,375
Weighted average common units outstanding:			
Basic	53,043	34,110	28,087
Diluted	53,344	34,110	28,146
Basic and diluted weighted average subordinated units outstanding	1,766	14,049	14,049
Basic and diluted net income (loss) per common unit	$ 0.27	$ (3.15)	$ 0.60
Basic and diluted net income (loss) per subordinated unit	$ (1.54)	$ (3.22)	$ 0.52

Distributions declared per limited partner unit	$ 2.10	$ 2.09	$ 2.01

See accompanying notes to consolidated financial statements.

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USA COMPRESSION PARTNERS, LP

Consolidated Statements of Changes in Partners' Capital

(in thousands)

	Partners' Capital					Total
	Common Units		Subordinated Units		General Partner Interest	Partners'
	Units	Amount	Units	Amount	Amount	Capital
Partners' capital, December 31, 2013	23,562	$ 447,562	14,049	$ 245,592	$ 14,573	$ 707,727
Vesting of phantom units	76	1,707	—	—	—	1,707
General partner contribution	—	—	—	—	294	294
Distributions and DERs	—	(53,854)	—	(27,746)	(1,729)	(83,329)
Issuance of common units under the DRIP	2,069	51,707	—	—	—	51,707
Issuance of common units	5,600	137,285	—	—	—	137,285
Unit-based compensation of equity classified awards	—	353	—	—	—	353
Modification of unit-based compensation	—	(1,170)	—	—	—	(1,170)
Net income	—	16,811	—	7,375	760	24,946
Partners' capital, December 31, 2014	31,307	$ 600,401	14,049	$ 225,221	$ 13,898	$ 839,520
Vesting of phantom units	101	1,844	—	—	—	1,844
Distributions and DERs	—	(69,480)		(29,151)	(2,503)	(101,134)
Issuance of common units under the DRIP	3,113	56,895	—	—	—	56,895
Issuance of common units	4,035	75,111	—	—	—	75,111
Unit-based compensation of equity classified awards	—	325	—	—	—	325
Net loss	—	(107,513)	—	(45,283)	(1,477)	(154,273)
Partners' capital, December 31, 2015	38,556	$ 557,583	14,049	$ 150,787	$ 9,918	$ 718,288
Vesting of phantom units	201	1,619	—	—	—	1,619
Distributions and DERs	—	(106,570)	—	(7,376)	(2,845)	(116,791)
Issuance of common units under the DRIP	2,708	31,812	—	—	—	31,812
Issuance of common units	5,175	80,892	—	—	—	80,892
Unit-based compensation of equity classified awards	—	762	—	—	—	762
Net income (loss)	—	14,282	—	(2,711)	1,364	12,935
Conversion of subordinated units to common units	14,049	140,700	(14,049)	(140,700)	—	—
	60,689	$ 721,080	—	$ —	$ 8,437	$ 729,517

Partners' capital, December 31, 2016

See accompanying notes to consolidated financial statements.

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USA COMPRESSION PARTNERS, LP

Consolidated Statements of Cash Flows

(in thousands)

	Year Ended December 31,		
	2016	2015	2014
Cash flow from operating activities:			
Net income (loss)	$ 12,935	$ (154,273)	$ 24,946
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization	92,337	85,238	71,156
Amortization of debt issue costs	2,108	1,702	1,224
Unit-based compensation expense	10,373	3,863	3,034
Net loss (gain) on sale of assets	772	(1,040)	(2,233)
Impairment of compression equipment	5,760	27,274	2,266
Impairment of goodwill	—	172,189	—
Changes in assets and liabilities:			
Accounts receivable, net	(6,580)	(439)	(2,659)
Inventory, net	(16,448)	(14,340)	(4,942)
Prepaid expenses	517	(1,580)	1,380
Other noncurrent assets	16	(3)	(39)
Accounts payable	(1,981)	(3,310)	(1,431)
Accrued liabilities and deferred revenue	3,888	2,120	9,189
Net cash provided by operating activities	103,697	117,401	101,891
Cash flow from investing activities:			
Capital expenditures, net	(51,240)	(281,050)	(381,943)
Proceeds from sale of property and equipment	336	1,735	1,420
Proceeds from insurance recovery	73	1,157	—
Net cash used in investing activities	(50,831)	(278,158)	(380,523)
Cash flows from financing activities:			
Proceeds from long-term debt	300,593	480,004	538,644
Payments on long-term debt	(344,410)	(345,681)	(364,714)
Net proceeds from issuance of common units	80,892	75,111	138,047
Cash paid for taxes related to net settlement of unit-based awards	(139)	(210)	(334)
Cash Distributions	(87,731)	(45,078)	(32,345)
General partner contribution	—	—	294
Financing costs	(2,013)	(3,388)	(961)
Net cash provided by (used in) financing activities	(52,808)	160,758	278,631
Increase (decrease) in cash and cash equivalents	58	1	(1)
Cash and cash equivalents, beginning of year	7	6	7
Cash and cash equivalents, end of year	$ 65	$ 7	$ 6
Supplemental cash flow information:			

Cash paid for interest	$ 20,489	$ 17,110	$ 12,622
Cash paid for income taxes	$ 230	$ 282	$ 115
Supplemental non-cash transactions:			
Non-cash distributions to certain limited partners (DRIP)	$ 31,812	$ 56,895	$ 51,707
Transfers from inventory to property and equipment	$ 7,771	$ 4,004	$ 5,971
Transfer from long term installment receivable to short term	$ (3,196)	$ (2,966)	$ (4,580)
Change in capital expenditures included in accounts payable and accrued liabilities	$ 11,753	$ 19,256	$ (16,515)
Capital Lease Transaction:			
Installment receivable	$ —	$ —	$ (24,820)
Property and equipment write-off	—	$ —	22,134
(Gain) on transaction	$ —	$ —	$ (2,686)

See accompanying notes to consolidated financial statements.

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USA COMPRESSION PARTNERS, LP

Notes to Consolidated Financial Statements

(1) The Partnership, Nature of Business, and Recent Transactions

Unless otherwise indicated, the terms “our”, “we”, “us”, “the Partnership” and similar language refer to USA Compression Partners, LP, collectively with its operating subsidiaries. We are a Delaware limited partnership. USA Compression GP, LLC, a Delaware limited liability company, serves as our general partner and is referred to herein as the “General Partner”. Through our operating subsidiaries, we provide compression services under term contracts with customers in the natural gas and crude oil industries, using natural gas compression packages that we design, engineer, own, operate and maintain. We provide compression services in a number of shale plays throughout the United States, including the Utica, Marcellus, Permian Basin, Delaware Basin, Eagle Ford, Mississippi Lime, Granite Wash, Woodford, Barnett, Haynesville, Niobrara and Fayetteville shales. Certain of our operating subsidiaries are borrowers under a revolving credit facility and the Partnership is a guarantor of that revolving credit facility (see Note 7). The accompanying consolidated financial statements include the accounts of the Partnership and its operating subsidiaries, all of which are wholly owned by us.

Net income (loss) is allocated to our general and limited partners using the two-class income allocation method. All intercompany balances and transactions have been eliminated in consolidation. Our limited partner units trade on the New York Stock Exchange under the ticker symbol “USAC”.

USA Compression Management Services, LLC (“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, 2016, USAC Management had 433 full time employees. None of our employees are subject to collective bargaining agreements.

(2) Summary of Significant Accounting Policies

(a)Cash and Cash Equivalents

Cash and cash equivalents consist of all cash balances. We consider investments in highly liquid financial instruments purchased with an original maturity of 90 days or less to be cash equivalents.

(b)Trade Accounts Receivable

Trade accounts receivable are recorded at the invoiced amount and do not bear interest. The allowance for doubtful accounts of $0.7 million and $2.1 million as of December 31, 2016 and 2015, respectively, is our best estimate of the amount of probable credit losses in our existing accounts receivable. We determine the allowance based upon historical write-off experience and specific customer circumstances. The determination of the allowance for doubtful accounts requires us to make estimates and judgments regarding our customers' ability to pay amounts due. On an ongoing basis, we conduct an evaluation of the financial strength of our customers based on payment history, the overall business climate in which our customers operate and specific identification of customer bad debt and make adjustments to the allowance as necessary. Our evaluation of our customers' financial strength is based on the aging of their respective receivables balance, customer correspondence, financial information and third-party credit ratings. Our evaluation of the business climate in which our customers operate is based on a review of various publicly-available materials regarding our customers' industries, including the solvency of various companies in the industry. Based on the aforementioned factors we increased the allowance account during the twelve months ended December 31, 2015. During the year ended December 31, 2016, we decreased our allowance for doubtful accounts by $1.1 million due mostly to collections on accounts that had previously been reserved, and additionally wrote-off $0.3 million of accounts that had been previously reserved. Since the overall energy industry continues to be volatile, it is not certain that the factors leading to an increase in the allowance for doubtful accounts during 2015, or the subsequent decrease during 2016, will continue. Due to the decrease in the allowance for doubtful accounts during 2016, we recognized a reduction of bad debt expense of $1.1 million for the year ended December 31, 2016. Bad debt expense for the year ended December 31, 2015 was $1.8 million.

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USA COMPRESSION PARTNERS, LP

Notes to Consolidated Financial Statements

(c)Inventory

Inventory consists of serialized and non-serialized parts used primarily in the repair of compression units. Serialized parts inventory are valued at the lower-of-cost-or-market value using the specific identification method, while non-serialized parts inventory is valued using the weighted-average cost method. Purchases of these assets are considered operating activities in the consolidated statement of cash flows.

Components of inventory as of December 31, 2016 and 2015 were as follows (in thousands):

	December 31,	
	2016	2015
Serialized parts	$ 17,943	$ 18,361
Non-serialized parts	11,927	825
Total Inventory, gross	29,870	19,186
Less: obsolete and slow moving reserve	(314)	(314)
Total Inventory, net	$ 29,556	$ 18,872

(d)Property and Equipment

Property and equipment are carried at cost except for (i) certain acquired assets which are recorded at fair value on their respective acquisition dates and (ii) impaired assets which are recorded at fair value on the last impairment evaluation date for which an adjustment was required. Overhauls and major improvements that increase the value or extend the life of compression equipment are capitalized and depreciated over 3 to 5 years. Ordinary maintenance and repairs are charged to cost of operations, exclusive of depreciation and amortization. Depreciation is calculated using the straight-line method over the estimated useful lives of the assets as follows:

Compression equipment, acquired new	25 years
Compression equipment, acquired used	9 - 25 years

Furniture and fixtures	7 years
Vehicles and computer equipment	3 - 7 years
Leasehold improvements	5 years

When property and equipment are retired or sold, its carrying value and the related accumulated depreciation are removed from our accounts and any associated gains or losses are recorded on our statements of operations in the period of sale or disposition.

Depreciation expense for the years ended December 31, 2016, 2015 and 2014 was $88.8 million, $81.7 million and $67.6 million, respectively.

(e)Impairments of Long-Lived Assets

Long-lived assets with recorded values that are not expected to be recovered through future cash flows are written-down to estimated fair value. We test our assets for impairment when events or circumstances indicate that the assets' carrying value may not be recoverable or will no longer be utilized in the operating fleet. The most common circumstance requiring compression units to be tested for impairment is when idle units do not meet the performance characteristics of our active revenue generating horsepower. 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 the carrying value exceeds the sum of the undiscounted cash flows associated with the operating fleet, an impairment loss equal to the amount of the carrying value exceeding the fair value of the asset is recognized. The fair value of the asset is measured using quoted market prices or, in the absence of quoted market prices, based on an estimate of discounted cash flows, the expected net sale proceeds compared to the other similarly configured fleet units we recently sold or a review of other units recently offered for sale by third parties, or the estimated component value of the equipment we plan to use.

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USA COMPRESSION PARTNERS, LP

Notes to Consolidated Financial Statements

Refer to Note 3 for more detailed information about impairment charges during the years ended December 31, 2016, 2015 and 2014.

(f)Revenue Recognition

Revenue from contract operations is recognized ratably as compression services are provided to customers under our fixed-fee contracts over the term of the contract, which generally ranges from one month to seven years. Parts and service revenue is recorded as parts are delivered or services are performed for the customer.

Revenue and the associated expense from installation services, which includes the installation of stations for our customers, is recorded using the percentage-of-completion method measured by the efforts-expended method. Revenue from installation services is included within the Parts and service revenue caption on our Consolidated Statements of Operations.

(g)Income Taxes

We have elected to be treated under SubChapter K of the Internal Revenue Code. Under SubChapter K, a partnership return is filed annually reflecting each partner’s allocable share of our income or loss. Therefore, no provision has been made for federal income tax in our accounts. For tax purposes, our net income (loss) is allocated to the partners in proportion to their respective interest in us.

As a partnership, all income, gains, losses, expenses, deductions and tax credits generated by us generally flow through to our unitholders. However, Texas imposes an entity-level income tax on partnerships. Refer to Note 6 for more detailed information about the Revised Texas Franchise Tax for the years ended December 31, 2016, 2015 and 2014.

(h)Fair Value Measurements

Accounting standards establish a framework for fair value measurement and disclosure. The standards apply to recurring and nonrecurring financial and non-financial assets and liabilities that require or permit fair value measurements. Among the required disclosures is the fair value hierarchy of inputs we use to value an asset or a liability. The three levels of the fair value hierarchy are described as follows:

Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that we have the ability to access at the measurement date.

Level 2 inputs are those other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly.

Level 3 inputs are unobservable inputs for the asset or liability.

Phantom unit awards granted to employees under our long-term incentive plan (the “LTIP”) are accounted for as a liability, and such liability is re-measured on a quarterly basis. The liability is based on the publicly quoted price of our common units, which is considered a Level 1 input. Refer to Note 9 for more information about unit-based compensation.

As part of the impairment analysis of goodwill as of December 31, 2015, the fair value of our goodwill was re-measured using Level 3 inputs. Refer to the Goodwill section below of this Note 2 for more information about this valuation as of December 31, 2015.

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USA COMPRESSION PARTNERS, LP

Notes to Consolidated Financial Statements

Net assets (liabilities) measured at fair value on a recurring basis are summarized below (in thousands):

	December 31,	
	2016	2015
Assets (Liabilities)	Level 1	Level 1
Unit-based compensation liability	$ (7,043)	$ (1,977)

As of December 31, 2016 and 2015, our financial instruments consisted primarily of cash and cash equivalents, trade accounts receivable, trade accounts payable and long-term debt. The book values of cash and cash equivalents, trade accounts receivable, and trade accounts payable are representative of fair value due to their short-term maturities. The carrying amount of long-term debt approximates fair value due to the floating interest rates associated with the debt.

(i)Pass Through Taxes

Sales taxes incurred on behalf of, and passed through to, customers are accounted for on a net basis.

(j)Use of Estimates

The preparation of our consolidated financial statements in conformity with accounting principles generally accepted in the United States of America (“GAAP”) requires us to make estimates and assumptions that affect the amounts reported in these consolidated financial statements and the accompanying results. Although these estimates are based on management’s available knowledge of current and expected future events, actual results could differ from these estimates.

(k)Identifiable Intangible Assets

Identifiable intangible assets, net consisted of the following (in thousands):

	Customer Relationships	Trade Names	Non-compete	Total
Gross Balance at December 31, 2014	$ 78,700	$ 15,600	$ 900	$ 95,200
Accumulated amortization	(12,782)	(3,120)	(525)	(16,427)
Net Balance at December 31, 2015	$ 65,918	$ 12,480	$ 375	$ 78,773
Gross Balance at December 31, 2015	$ 78,700	$ 15,600	$ 900	$ 95,200
Accumulated amortization	(15,517)	(3,744)	(750)	(20,011)
Net Balance at December 31, 2016	$ 63,183	$ 11,856	$ 150	$ 75,189

Identifiable intangible assets are recorded at cost and amortized using the straight-line method over their estimated useful lives, which is the period over which the assets are expected to contribute directly or indirectly to our future cash flows. The estimated useful lives range from 4 to 30 years. Amortization expense for each of the years ended December 31, 2016, 2015 and 2014 was $3.6 million. The expected amortization of the identifiable intangible assets for each of the five succeeding years is as follows (in thousands):

Year Ending December 31,	Total
2017	$ 3,509
2018	3,359
2019	3,359
2020	3,359
2021	3,359

We assess identifiable intangible assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. We did not record any impairment of identifiable intangible assets in the years ended December 31, 2016, 2015 or 2014.

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USA COMPRESSION PARTNERS, LP

Notes to Consolidated Financial Statements

(l)Goodwill

Goodwill represents consideration paid in excess of the fair value of the identifiable net assets acquired in a business combination. Goodwill is not amortized, but is reviewed for impairment annually based on the carrying values as of October 1, or more frequently if impairment indicators arise that suggest the carrying value of goodwill may not be recovered.

As of October 1, 2016 and 2015, a quantitative assessment was performed to determine whether the fair value of our single reporting unit was greater than its carrying value. As of October 1, 2016 and 2015, the fair value was determined to be in excess of the carrying value.

Due to the identification of certain impairment indicators during the fourth quarter of 2015, specifically (1) the decline in the market price of our common units, (2) the sustained decline in global commodity prices, and (3) the decline in performance of the Alerian MLP Index, we prepared a quantitative assessment of our goodwill as of December 31, 2015. This assessment indicated that the calculated fair value was less than the carrying value. As such, we prepared a Step 2 impairment test which measured the amount of the impairment loss and involved a hypothetical allocation of the estimated fair value among the reporting unit’s assets and liabilities. The carrying value of goodwill exceeded the implied value of goodwill and an impairment charge was recorded for $172.2 million during the year ended December 31, 2015. The fair value of our single reporting unit was calculated using the Discounted Cash Flow Method, an income approach. This method utilizes Level 3 inputs from the fair value hierarchy. The impairment of goodwill was primarily the result of the sustained decline in the market price of our common units. The continued decline in commodity prices adversely impacted many of our customers and resulted in a significant decline in their future capital expansion plans. This in turn reduced our expected future capital expansion plans and in turn, our estimated future cash flows as of December 31, 2015.

We had approximately $35.9 million of goodwill remaining on the balance sheet as of December 31, 2016 and 2015. No impairment of goodwill was recorded in the years ended December 31, 2016 and 2014.

(m)Capitalized Interest

For the years ended December 31, 2016, 2015 and 2014, we capitalized $0.2 million, $0.3 million and $0.3 million, respectively, of interest expense for interest costs incurred during the period related to upfront payments required in acquiring certain compression units.

(n)Operating Segment

We operate in a single business segment, the compression services business.

(3) Property and Equipment

Property and equipment consisted of the following (in thousands):

	December 31,	
	2016	2015
Compression equipment	$ 1,551,157	$ 1,520,835
Furniture and fixtures	625	669
Automobiles and vehicles	18,979	19,284
Computer equipment	23,394	21,457
Leasehold improvements	1,392	1,197
Total Property and equipment, gross	1,595,547	1,563,442
Less: accumulated depreciation and amortization	(327,973)	(245,399)
Total Property and equipment, net	$ 1,267,574	$ 1,318,043

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USA COMPRESSION PARTNERS, LP

Notes to Consolidated Financial Statements

As of December 31, 2016 and 2015, there was $1.4 million and $13.1 million, respectively, of property and equipment purchases in accounts payable and accrued liabilities.

During the year ended December 31, 2016, we abandoned certain assets and incurred a $1.0 million loss. During the year ended December 31, 2015, insurance recoveries of $1.2 million were received on previously impaired compression equipment. Each of these is reported within the Loss (gain) on sale of assets caption in the Consolidated Statements of Operations.

During the years ended December 31, 2016 and 2015, we evaluated the future deployment of our idle fleet under current market conditions and determined to retire and either sell or re-utilize the key components of 29 compressor units, or approximately 15,000 horsepower, and 166 compressor units, or approximately 58,000 horsepower, respectively, that were previously used to provide services in our business. In both periods the cause of the impairment was related to certain performance characteristics of the impaired equipment, such as excessive maintenance costs and the inability of the equipment to meet current emission standards without retrofitting. We determined that this equipment was unlikely to be accepted by customers under current market conditions. This compression equipment was written down to its respective estimated salvage value, measured using quoted market prices, or the estimated component value of the equipment we plan to use. As a result of our decision to retire, sell or re-utilize these compressor units, management performed an impairment review and recorded $5.8 million, $27.3 million and $2.3 million in impairment of compression equipment for the years ended December 31, 2016, 2015 and 2014, respectively.

(4) Installment Receivable

On June 30, 2014, we entered into a FMV Bargain Purchase Option Grant Agreement (the “Capital Lease Transaction”) with a customer, pursuant to which we granted a bargain purchase option to the customer with respect to certain compressor packages leased to the customer (each a “Subject Compressor Package”). The bargain purchase option provides the customer with an option to acquire the equipment at a value significantly less than the fair market value at the end of the lease term.

On November 1, 2016, we entered into a second capital lease transaction with a customer with respect to certain assets leased to the customer.

Both capital leases were accounted for as sales type leases and, as of December 31, 2016 and 2015, resulted in a current installment receivable of $8.9 million and $3.0 million, respectively, included in other accounts receivable and a long-term installment receivable of $14.1 million and $17.3 million, respectively. Additionally, we recorded a $0.3 million gross profit margin related to the 2016 capital lease for the year ended December 31, 2016 and a $2.6 million gain on sale of assets related to the Capital Lease Transaction for the year ended December 31, 2014.

Revenue and interest income related to the both capital leases is recognized over the respective lease terms, which range from 6 months to 7 years. We recognize maintenance revenue within Contract operations revenue and interest income within Interest expense, net on the Consolidated Statements of Operations. For the years ended December 31, 2016, 2015 and 2014, maintenance revenue related to the Capital Lease Transaction was $1.3 million, $1.3 million and $0.9 million, respectively. Interest income related to both capital leases was $1.5 million, $1.6 million and $1.3 million in the years ended December 31, 2016, 2015 and 2014, respectively.

(5) Accrued Liabilities

The primary components of accrued liabilities were accrued payroll and benefits and accrued property taxes. We recognized $6.9 million and $7.1 million of accrued payroll and benefits as of December 31, 2016 and 2015, respectively. We recognized $6.6 million and $4.1 million of accrued property taxes as of December 31, 2016 and 2015, respectively.

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(6) Income Tax Expense

We are subject to the Revised Texas Franchise Tax ("Texas Margin Tax"). We do not conduct business in any other state where a similar tax is applied. This margin tax requires certain forms of legal entities, including limited partnerships, to pay a tax of 1.0% (or 0.75% for 2015 and forward) on its "margin," as defined in the law, based on 2016 results. The margin tax base to which the tax rate is applied is the least of (1) 70% of total revenues for federal income tax purposes, (2) total revenue less cost of goods sold or (3) total revenue less compensation for federal income tax purposes. For the years ended December 31, 2016, 2015 and 2014, we recorded expense related to the Texas margin tax of $0.4 million, $1.1 million and $0.1 million, respectively.

Components of our income tax expense related to the Texas Margin Tax are as follows (in thousands):

	Year Ended December 31,		
	2016	2015	2014
Current tax expense	$ 182	$ 211	$ 103
Deferred tax expense	239	874	—
Total income tax expense	$ 421	$ 1,085	$ 103

Deferred income tax balances are the direct effect of temporary differences between the financial statement carrying amounts and the tax basis of assets and liabilities at the enacted tax rates expected to be in effect when the taxes are actually paid or recovered. The tax effects of temporary differences related to property and equipment that give rise to deferred tax liabilities are as follows (in thousands):

	December 31,	
	2016	2015
Net deferred tax liabilities	$ 1,113	$ 874

The Financial Accounting Standards Board's ("FASB") ASC Topic 740-10 ("ASC 740-10") provides guidance on measurement and recognition in accounting for income tax uncertainties and provides related guidance on derecognition, classification, disclosure, interest, and penalties. As of December 31, 2016, we had no material

unrecognized tax benefits (as defined in ASC 740-10). We do not expect to incur interest charges or penalties related to our tax positions, but if such charges or penalties are incurred, our policy is to account for interest charges as Interest expense, net and penalties as Income tax expense in the Consolidated Statements of Operations.

(7) Long-Term Debt

Our first lien long-term debt consisted of the following (in thousands):

	December 31,	
	2016	2015
Revolving Credit Facility	$ 685,371	$ 729,187

On January 6, 2015, we amended our revolving credit facility, whereby, the aggregate commitment under the revolving credit facility increased from $850.0 million to $1.1 billion (subject to availability under our borrowing base), with a further potential increase of $200 million and the maturity date of the revolving credit facility was extended to January 6, 2020. In addition, this amendment provided additional flexibility under the financial covenants of the revolving credit facility.

On March 18, 2016, we further amended our revolving credit facility to, among other things, (i) modify the leverage ratio covenant to be (A) 5.75 to 1.0 as of the end of the fiscal quarter ending December 31, 2016, (B) 5.50 to 1.0 as of the end of the respective fiscal quarters ending March 31, 2017 and June 30, 2017, (C) 5.25 to 1.0 as of the end of the respective fiscal quarters ending September 30, 2017 and December 31, 2017 and (D) 5.00 to 1.0 thereafter, and (ii) amend certain other provisions of the credit agreement, all as more fully set forth in the amendment documents.

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The revolving credit facility permits us to make distributions of available cash to unitholders so long as (a) no default under the facility has occurred, is continuing or would result from the distribution, (b) immediately prior to and after giving effect to such distribution, we are in compliance with the facility's financial covenants and (c) immediately after giving effect to such distribution, we have availability under the revolving credit facility of at least $20 million. In addition, the revolving credit facility contains various covenants that may limit, among other things, our ability to (subject to exceptions):

- grant liens;
- make certain loans or investments;
- incur additional indebtedness or guarantee other indebtedness;
- enter into transactions with affiliates;
- merge or consolidate;
- sell our assets; or
- make certain acquisitions.

The revolving credit facility also contains various financial covenants, including covenants requiring us to maintain:

- a minimum EBITDA to interest coverage ratio of 2.5 to 1.0, determined as of the last day of each fiscal quarter; and
- a maximum funded debt to EBITDA ratio, determined as of the last day of each fiscal quarter, for the annualized trailing three months of (a) 5.75 to 1.0 as of the end of fiscal quarter ending December 31, 2016, (b) 5.50 to 1.0 as of the end of the respective fiscal quarters ending March 31, 2017 and June 30, 2017, (c) 5.25 to 1.0 as of the end of the respective fiscal quarters ending September 30, 2017 and December 31, 2017 and (d) 5.00 to 1.0 thereafter, in each case subject to a provision for increases to such thresholds by 0.5 in connection with certain future acquisitions for the six consecutive month period following the period in which any such acquisition occurs.

If a default exists under the revolving credit facility, the lenders will be able to accelerate the maturity on the amount then outstanding and exercise other rights and remedies.

We paid various loan fees and incurred costs in respect of the revolving credit facility in the amount of $2.0 million, $3.4 million, and $0.2 million in 2016, 2015 and 2014 respectively, which were capitalized to loan costs that will be amortized through January 2020.

As of December 31, 2016 and 2015, we were in compliance with all of our covenants under the revolving credit facility.

As of December 31, 2016, we had outstanding borrowings under our revolving credit facility of $685.4 million, $414.6 million of borrowing base availability and, subject to compliance with the applicable financial covenants, available borrowing capacity of $152.3 million. The borrowing base consists of eligible accounts receivable, inventory and compression units. The largest component, representing 94% and 91% of the borrowing base December 31, 2016 and 2015, was eligible compression units. Eligible compression units consist of compressor packages that are leased, rented or under service contracts to customers and carried in the financial statements as fixed assets. Our interest rate in effect for all borrowings under our revolving credit facility as of December 31, 2016 and 2015 was 2.94% and 2.26%, respectively, with a weighted- average interest rate of 2.55%, 2.24%, and 2.22% during 2016, 2015 and 2014, respectively. There were no letters of credit issued as of December 31, 2016 and 2015.

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The revolving credit facility matures in January 2020 and we expect to maintain this facility for the term. The facility is a “revolving credit facility” that includes a “springing” lock box arrangement, whereby remittances from customers are forwarded to a bank account controlled by us. We are not required to use such remittances to reduce borrowings under the facility, unless there is a default or excess availability under the facility is reduced below $20 million. As the remittances do not automatically reduce the debt outstanding absent the occurrence of a default or a reduction in excess availability below $20 million, the debt has been classified as long-term as of December 31, 2016 and 2015.

Maturities of long-term debt are as follows (in thousands):

Year Ending December 31,	
2017	$ —
2018	—
2019	—
2020	685,371
2021	—
Total Debt	$ 685,371

In the event that any of our operating subsidiaries guarantees any series of the debt securities as described in our registration statement filed on Form S-3 (Reg. No. 333-193724), such guarantees will be full and unconditional and made on a joint and several basis for the benefit of each holder and the Trustee. However, such guarantees will be subject to release, subject to certain limitations, as follows (i) upon the sale, exchange or transfer, whether by way of a merger or otherwise, to any Person that is not our affiliate, of all our direct or indirect limited partnership or other equity interest in such Subsidiary Guarantor; or (ii) upon our or USA Compression Finance Corp.’s (together, the “Issuers”) delivery of a written notice to the Trustee of the release or discharge of all guarantees by such Subsidiary Guarantor of any Debt of the Issuers other than obligations arising under the indenture governing such debt and any debt securities issued under such indenture, except a discharge or release by or as a result of payment under such guarantees. Capitalized terms used but not defined in this paragraph are defined in the Form of Indenture filed as exhibit 4.1 to such registration statement.

(8) Partner's Capital

As of February 9, 2017, USA Compression Holdings, LLC held 23,929,263 common units and owned and controlled our General Partner which held an approximate 1.3% general partner interest (the "General Partner's Interest") and the incentive distribution rights ("IDRs"). See the Consolidated Statement of Changes in Partners' Capital.

The limited partners holding our common units have the following rights, among others:

- Right to receive distributions of our available cash (as defined in the Partnership Agreement) within 45 days after the end of each quarter;
- Right to transfer limited partner unit ownership to substitute limited partners;
- Right to approve certain amendments of our Partnership Agreement;
- Right to electronic access of an annual report, containing audited financial statements and a report on those financial statements by our independent public accountants within 90 days after the close of the fiscal year end; and
- Right to receive information reasonably required for tax reporting purposes within 90 days after the close of the calendar year.

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Subordinated Units

All of our outstanding subordinated units, which were held by USA Compression Holdings, LLC, converted to common units on a one-for-one basis on February 16, 2016 upon payment of our quarterly distribution on February 12, 2016.

Incentive Distribution Rights

Our General Partner holds all of the IDRs. The IDRs represent the right to receive an increasing percentage of quarterly distributions of available cash from operating surplus after the minimum quarterly distribution and the target distribution levels have been achieved.

The following table illustrates the percentage allocations of Available Cash from Operating Surplus between the unitholders and our General Partner based on the specified target distribution levels. The amounts set forth under "Marginal Percentage Interest in Distributions" are the percentage interests of our General Partner and our unitholders in any Available Cash from Operating Surplus we distribute up to and including the corresponding amount in the column "Total Quarterly Distribution per Unit." The percentage interests shown for our unitholders and our General Partner for the minimum quarterly distribution are also applicable to quarterly distribution amounts that are less than the minimum quarterly distribution. The percentage interests set forth below for our General Partner include its General Partner's Interest, and assume our General Partner has contributed any additional capital necessary to maintain its General Partner's Interest, our General Partner has not transferred the IDRs and there are no arrearages on common units.

	Total Quarterly Distributions per Unit	Marginal Percentage Interest in Distributions			
		Unitholders		General Partner	
Minimum Quarterly Distribution	$0.425	98.7	%	1.3	%
First Target Distribution	up to $0.4888	98.7	%	1.3	%
Second Target Distribution	above $0.4888 up to $0.5313	85.7	%	14.3	%
Third Target Distribution	above $0.5313 up to $0.6375	75.7	%	24.3	%

Thereafter	above $0.6375	50.7	%	49.3	%

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Cash Distributions

We have declared quarterly distributions per unit to our limited partner unitholders of record, including holders of our common, subordinated and phantom units and distributions paid to our General Partner, including our General Partner's Interest and IDRs, as follows (dollars in millions, except distribution per unit):

Payment Date	Distribution per Limited Partner Unit	Amount Paid to Common Unitholders	Amount Paid to Subordinated Unitholder	Amount Paid to General Partner	Amount Paid to Phantom Unitholders	Total Distribution
February 14, 2014	$ 0.480	$ 11.3	$ 6.7	$ 0.4	$ —	$ 18.4
May 15, 2014	0.490	11.8	6.9	0.4	0.2	19.3
August 14, 2014	0.500	15.1	7.0	0.5	0.2	22.8
November 14, 2014	0.505	15.5	7.1	0.5	0.2	23.3
2014 Total Distributions	$ 1.975	$ 53.7	$ 27.7	$ 1.8	$ 0.6	$ 83.8
February 13, 2015	$ 0.510	$ 16.0	$ 7.2	$ 0.5	$ 0.1	$ 23.8
May 15, 2015	0.515	16.6	7.2	0.6	0.2	24.6
August 14, 2015	0.525	17.2	7.4	0.7	0.2	25.5
November 13, 2015	0.525	19.7	7.4	0.7	0.2	28.0
2015 Total Distributions	$ 2.075	$ 69.5	$ 29.2	$ 2.5	$ 0.7	$ 101.9
February 12, 2016	$ 0.525	$ 20.2	$ 7.4	$ 0.7	$ 0.8	$ 29.1
May 13, 2016	0.525	28.4	—	0.7	0.7	29.8
August 12, 2016	0.525	28.8	—	0.7	0.7	30.2
November 14, 2016	0.525	29.1	—	0.7	0.6	30.4
2016 Total Distributions	$ 2.100	$ 106.5	$ 7.4	$ 2.8	$ 2.8	$ 119.5

Announced Quarterly Distribution

On January 19, 2017, we announced a cash distribution of $0.525 per unit on our common units. The distribution will be paid on February 14, 2017 to unitholders of record as of the close of business on February 3, 2017. USA Compression Holdings, LLC, the owner of approximately 39% of our outstanding limited partner interests has elected

to reinvest 30% of this distribution with respect to its units pursuant to our distribution reinvestment plan (the "DRIP").

Dividend Reinvestment Program

For the years ended December 31, 2016, 2015 and 2014, distributions of $31.8 million, $56.9 million and $51.7 million, respectively, were reinvested under the DRIP resulting in the issuance of 2.7 million, 3.1 million and 2.1 million common units, respectively. Such distributions are treated as non-cash transactions in the accompanying Consolidated Statements of Cash Flows.

Equity Offerings

On December 8, 2016, we closed a public offering of 5,175,000 common units at a price to the public of $16.25 per common unit. We used the net proceeds of $80.9 million (net of underwriting discounts and commissions and offering expenses) to reduce the indebtedness outstanding under our revolving credit facility.

On September 15, 2015, we closed a public offering of 4,000,000 common units at a price to the public of $19.33 per common unit. We used the net proceeds of $74.4 million (net of underwriting discounts and commissions and offering expenses) to reduce the indebtedness outstanding under our revolving credit facility.

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On May 21, 2015, we issued 34,921 common units in a private placement for $0.7 million in a transaction that was exempt from registration under Section 4(a)(2) of the Securities Act. We used the proceeds from the private placement for general partnership purposes. There were no other unregistered sales of securities during the years ended December 31, 2016, 2015 or 2014.

On May 19, 2014, we closed a public offering of 6,600,000 common units, of which 5,600,000 common units were sold by us and 1,000,000 common units were sold by certain selling unitholders, at a price to the public of $25.59 per common unit. The selling unitholders granted the underwriters an option to purchase up to an additional 990,000 common units to cover over-allotments, which was exercised by the underwriters in full and closed on May 27, 2014. We used the net proceeds of $138.0 million (net of underwriting discounts and commissions and offering expenses) to reduce the indebtedness outstanding under the revolving credit facility.

On April 23, 2014, our registration statement on Form S-3 (Reg. No. 333-193724) (as amended, the “Shelf Registration Statement”) was declared effective by the Securities and Exchange Commission. Under the Shelf Registration Statement, we registered the offer and sale of (1) up to $1.0 billion aggregate principal amount of our securities, including common units and other classes of units representing limited partner interests us, debt securities and guarantees of debt securities and (2) up to 27,074,118 common units held by certain selling unitholders and up to 6,266,024 common units that may be issued to such selling unitholders under the DRIP.

Earnings Per Common and Subordinated Unit

The computations of earnings per common unit and subordinated unit are based on the weighted average number of common units and subordinated units, respectively, outstanding during the applicable period. The subordinated units and our General Partner’s Interest (including its IDRs) meet the definition of participating securities as defined by the FASB’s Accounting Standard Codification (“ASC”) Topic 260 Earnings Per Share; therefore, we apply the two-class method of income allocation in computing earnings per unit. Basic earnings per common and subordinated unit are determined by dividing net income (loss) allocated to the common and subordinated units, respectively, after deducting the net income (loss) amount allocated to our General Partner (including distributions to our General Partner on our General Partner’s Interest and its IDRs), by the weighted average number of outstanding common and subordinated units, respectively, during the period. Net income (loss) is allocated to the common units, subordinated units and our General Partner’s Interest (including its IDRs) based on their respective shares of the distributed and undistributed earnings for the period. To the extent cash distributions exceed net income (loss) for the period, the excess distributions are allocated to all participating interests outstanding based on their respective ownership percentages. Diluted earnings per unit are computed using the treasury stock method, which considers the potential issuance of limited partner units associated with the LTIP. Unvested phantom units are not included in basic earnings

per unit, as they are liability classified and as such are not considered to be participating securities, but are included in the calculation of diluted earnings per unit. Incremental unvested phantom units outstanding represent the only difference between our basic and diluted weighted average common units outstanding during the years ended December 31, 2016, 2015 and 2014. For the year ended December 31, 2015, approximately 121,000 incremental phantom units were excluded from the calculation of diluted units because the impact was anti-dilutive.

(9) Unit-Based Compensation

Class B Units

During 2011 and 2013, USA Compression Holdings LLC issued to certain employees and members of its management, who provide services to us, Class B non-voting units. These Class B units are liability-classified profits interest awards which have a service condition.

The holders of Class B units in USA Compression Holdings LLC are entitled to a cash payment of 10% of net proceeds primarily from a monetization event, as defined under the provisions of the Amended and Restated Limited Liability Company Agreement of USA Compression Holdings LLC, or the Holdings Operating Agreement, related to these Class B unit awards, in excess of USA Compression Holdings LLC's Class A unitholder's capital contributions and a return on each Class A unitholder's capital account, compounded annually (both of which are due upon a

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monetization event), to the extent of vested units over total units of the respective class. Each holder of Class B units is then allocated their pro-rata share of the respective class of unit's entitlement based on the number of units held over the total number of units in that class of units. The Class B units vest 25% on the first anniversary date of the grant date and then monthly for the next three years (at the rate of 1/36 per month) subject to certain continued employment. The units have no expiry date provided the employee remains employed with USA Compression Holdings, LLC or one of its subsidiaries.

The Class B units vesting schedule consisted of the following as of December 31 (in thousands, except unit amounts):

	Class B Interest Units	
	Vested	Unvested
Balance of awards as of December 31, 2013	1,039,063	210,937
Vesting (1)	85,937	(85,937)
Balance of awards as of December 31, 2014	1,125,000	125,000
Vesting (1)	54,687	(54,687)
Forfeitures	(125,000)	—
Balance of awards as of December 31, 2015	1,054,687	70,313
Vesting	46,875	(46,875)
Balance of awards as of December 31, 2016	1,101,562	23,438

(1) Includes correcting adjustments to historical amounts.

Fair value of the Class B units is based on enterprise value calculated by a predetermined formula. We recognized no unit-based compensation expense related to these Class B units during any of the periods presented above.

Our initial public offering constituted a qualified public offering for purposes of certain vesting provisions of the employee holder's Class B Units, which resulted in 50% of certain employee's unvested Class B Units vesting. Any remaining unvested Class B Units generally (i) vest 25% percent on the first anniversary date of the grant date and (ii) with respect to the remaining Class B Units, will vest monthly for the next three years (at the rate of 1/36 per month) subject to the employee's continued employment on each applicable vesting date. If any employee holder's employment is terminated by our General Partner without cause or the employee resigns for good reason, the remaining unvested Class B Units will vest in full. As used in the Holdings Operating Agreement, "good reason" and "cause" have the meanings set forth in each employee's employment agreement.

Long-Term Incentive Plan

In connection with our initial public offering, the board of directors of our General Partner (the "Board") adopted the LTIP for employees, consultants and directors of our General Partner and any of its affiliates who perform services for us. The LTIP consists of unit options, unit appreciation rights, restricted units, phantom units, distribution equivalent rights ("DERs"), unit awards, profits interest units and other unit-based awards. The LTIP initially limits the number of common units that may be delivered pursuant to awards under the plan to 1,410,000 common units. Awards that are forfeited, cancelled, paid or otherwise terminate or expire without the actual delivery of units will be available for delivery pursuant to other awards. The LTIP is administered by the Board or a committee thereof.

In February 2014, the Board approved a modification to all of the phantom unit awards that were granted to employees pursuant to the LTIP during the 2013 fiscal year. The modification provided all employees with phantom unit awards granted during 2013 with an option of settling a portion of their award in cash and a portion in units. The amount that can be settled in cash is in excess of the employee's minimum statutory tax-withholding rate. ASC Topic 718, Compensation-Stock Compensation, requires the entire amount of an award with such features to be accounted for as a liability. Under the liability method of accounting for unit-based compensation, we re-measure the fair value of the award at each financial statement date until the award vests or is cancelled. The fair value is re-measured at the end of

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each reporting period using the market price of the common units. During the requisite service period (the vesting period of the awards), compensation cost is recognized using the proportionate amount of the award's fair value that has been earned through service to date. The total incremental compensation cost recorded in February 2014 as a result of the modification was $1.2 million.

During the years ended December 31, 2016 and 2015, an aggregate of 1,084,003 and 320,636, respectively, phantom units (including the corresponding DERs) were granted under the LTIP to our General Partner's executive officers and employees and independent directors. The phantom units granted in 2016 and 2015 provide the employees with an option of settling a portion of their award in cash and a portion in units. The phantom units (including the corresponding DERs) awarded are subject to restrictions on transferability, customary forfeiture provisions and time vesting provisions generally. The phantom units granted to employees during 2015 vest over a three year service period, whereby one-third of each award vests on the first, second, and third anniversaries of the date of grant.

The phantom units granted to employees during 2016 are subject to time-based and market-based criteria. We refer to the component of the grants subject to the time-based criteria as "Standard Units" and we refer to the component of the grants subject to the market-based criteria as "Performance Units". Standard Units vest over a three year service period, consistent with historical phantom units granted. Performance Units vest at the end of a three year service period, subject to a market condition. The market condition metric is our total shareholder return over the three year service period, relative to the total shareholder returns of a defined peer group of companies over the same three year period. Our ranking determines the rate at which the Performance Units convert into our common shares, which can range from zero to 200 percent of the Performance Unit grant.

The phantom units will generally vest in full in the event of a change in control and a termination of employment. Grants of phantom units to the independent directors of our General Partner generally vest in full on the one year anniversary of the grant date. Award recipients do not have all the rights of a unitholder in the partnership with respect to the phantom units until the units have vested.

Phantom units granted to employees during the years ended December 31, 2016 and 2015 are accounted for as a liability and are re-measured to fair value at the end of each reporting period using the market price of the common units for Standard Units. Fair value for the Performance Units was determined using a Monte Carlo simulation model, which incorporated a number of factors in its valuation including the vesting periods of our awards, the expected volatility of our units, expected dividends and the risk free interest rate. As of December 31, 2016 and 2015, our total unit-based compensation liability was $7.0 million and $2.0 million, respectively. Phantom units granted to independent directors do not have a cash settlement option and as such we account for these awards as equity. During the requisite service period, compensation cost is recognized using the proportionate amount of the award's fair value

that has been earned through service to date.

Our General Partner's executive officers, employees and independent directors were granted these awards to incentivize them to help drive our future success and to share in the economic benefits of that success. The compensation costs associated with these awards were recorded in selling, general and administrative expense. During the years ended December 31, 2016, 2015 and 2014, we recognized $10.4 million, $3.9 million and $3.0 million, respectively, of compensation expense associated with these awards. During the years ended December 31, 2016, 2015 and 2014, amounts we paid for income tax withholdings related to the vesting of awards under the LTIP were $0.1 million, $0.2 million and $0.2 million, respectively, and the value of phantom units that vested and were redeemed by us for cash was immaterial for all periods presented in this report. The total fair value and intrinsic value of the phantom units vested under the LTIP was $1.9 million, $2.2 million, and $2.4 million during the years ended December 31, 2016, 2015 and 2014, respectively.

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The following table summarizes information regarding phantom unit awards for the periods presented:

	Number of Units	Weighted-Average Grant Date Fair Value per Unit(1)
Phantom units outstanding at December 31, 2013	229,991	$ 20.02
Granted	187,856	26.29
Vested	88,707	17.20
Forfeited	60,038	18.81
Phantom units outstanding at December 31, 2014	269,102	$ 23.65
Granted	320,636	19.04
Vested	111,991	22.96
Forfeited	20,666	21.77
Phantom units outstanding at December 31, 2015	457,081	$ 22.10
Granted	1,084,003	7.27
Vested	212,896	21.25
Forfeited	158,275	9.83
Phantom units outstanding at December 31, 2016	1,169,913	$ 9.81

(1) Determined by dividing the aggregate grant date fair value of awards by the number of awards issued.

The unrecognized compensation cost associated with phantom unit awards was an aggregate $13.3 million as of December 31, 2016. We expect to recognize the unrecognized compensation cost for these awards on a weighted-average basis over a period of 1.9 years.

Each phantom unit granted to an independent director is granted in tandem with a corresponding DER, which remains outstanding and unpaid from the grant date until the earlier of the payment or forfeiture of the related phantom units. Each vested DER shall entitle the participant to receive payments in the amount equal to any distributions we make following the grant date in respect of the common unit underlying the phantom unit to which such DER relates. Accumulated but unpaid DERs are never paid if the underlying phantom unit award is forfeited by the independent director.

Each phantom unit granted to an executive officer or an employee is granted in tandem with a corresponding DER, which is paid quarterly on the distribution date from the grant date until the earlier of the settlement or the forfeiture of the related phantom units. For the Performance Units granted during 2016, DERs are paid on 100% of the granted units regardless of whether the ultimate number of units that vest fall within the range from zero to 200%.

(10) Employee Benefit Plans

A 401(k) plan is available to all of our employees. The plan permits employees to make contributions up to 20% of their salary, up to statutory limits, which was $18,000 in 2016. The plan provides for discretionary matching contributions by the Partnership on an annual basis. Aggregate matching contributions we made were $0.8 million, $0.8 million and $0.7 million for the years ended December 31, 2016, 2015 and 2014, respectively.

(11) Transactions with Related Parties

William Shea, Jr., who has served as a director of our General Partner since June 2011, served as Chief Executive Officer of the general partner of a customer from March 2010 to March 2014. For the year ended December 31, 2014, subsidiaries of this customer made compression service payments to us of approximately $0.6 million.

John Chandler, who has served as a director of our General Partner since October 2013, has served as a director of a customer since October 2014. During the years ended December 31, 2016, 2015 and the period of Mr. Chandler’s appointment for the year ended December 31, 2014, we recognized approximately $8.5 million, $ 8.8 million and $1.7

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million, respectively, in revenue on compression services and $1.1 million and $1.3 million, respectively, in accounts receivable from this customer on the Consolidated Balance Sheets as of December 31, 2016 and 2015.

We provide compression services to entities affiliated with Riverstone/Carlyle Global Energy and Power Fund IV, L.P. (“Riverstone”), which owns a majority of the membership interests in USA Compression Holdings, LLC. As of December 31, 2016, USA Compression Holdings, LLC owned and controlled our General Partner and owned 39% of our limited partner interests. We recognized approximately $0.4 million in revenue from compression services from such affiliated entities for the year ended December 31, 2016. We recognized no revenue from such controlled entities during the year ended December 31, 2015. We may provide compression services to additional entities affiliated with Riverstone in the future, and any significant transactions will be disclosed.

(12) Recent Accounting Pronouncements

In July 2015, the FASB agreed to defer by one year the mandatory effective date of its revenue recognition standard to annual and interim periods in fiscal years beginning after December 15, 2017, but has also provided entities the option to adopt it as of the original effective date. We are currently evaluating the impact, if any, of this ASU on our consolidated financial statements. We expect to elect the modified retrospective transition method for adoption to annual and interim periods in fiscal years beginning after December 15, 2017. We expect to identify similar performance obligations under the new accounting standard as compared with deliverables and separate units of account previously identified. As a result we expect the timing of our revenue recognition will not be materially impacted under this new accounting standard. Further, we expect the revenue amounts we historically reported will not materially change as we apply the modified retrospective provisions of this new standard. We do not expect significant changes to our current accounting policies and are in process of developing pro-forma quantitative and qualitative disclosures to reflect the nature, timing and uncertainly of cash flows, changes in contract balances, and significant judgments related to our performance obligations.

Also in July 2015, the FASB issued an ASU that changes the measurement principle for inventory from the lower of cost or market to the lower of cost and net realizable value. This ASU requires prospective adoption for inventory measurements for annual and interim periods in fiscal years beginning after December 15, 2016. Early adoption is permitted. We concluded that our adoption of this ASU will not have a material impact on our consolidated financial statements.

In February 2016, the FASB issued a new leasing standard that increases transparency and comparability among organizations by, among other things, requiring lessees to recognize lease assets and lease liabilities on the balance sheet and requiring both lessees and lessors to disclose expanded qualitative and quantitative information about leasing arrangements. Lessor accounting will remain substantially similar to current U.S. GAAP but with some changes to conform and align guidance with the new lessee guidance and other areas within U.S. GAAP, such as Accounting Standards Codification Topic 606, Revenue from Contracts with Customers. The new leasing standard requires modified retrospective adoption, with elective reliefs, and becomes effective for public business entities for annual and interim periods in fiscal years beginning after December 15, 2018. We expect to adopt this new standard on January 1, 2019. We are still in the process of evaluating the financial impact from adopting this standard on our consolidated financial statements.

In March 2016, the FASB issued an ASU that clarifies the implementation guidance on principal versus agent considerations. The amendments are intended to improve the operability and understandability of the implementation guidance on principal versus agent considerations within the revenue recognition update. The effective date and transition requirements for the amendments in this update are the same as the effective date and transition requirements of the revenue recognition update. We are currently evaluating the impact, if any, of this ASU along with the revenue recognition ASU, on our consolidated financial statements.

In March 2016, the FASB issued an ASU that simplifies several aspects of accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. For public business entities, the amendments within this ASU are effective for annual and interim periods in fiscal years beginning after December 15, 2016. We concluded that our adoption of this ASU will not have a material impact on our consolidated financial statements.

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In June 2016, the FASB issued new guidance for the accounting for credit losses on certain financial instruments. This guidance will become effective for interim and annual periods beginning after December 15, 2019, with early adoption permitted by one year. This ASU requires immediate recognition of estimated credit losses expected to occur over the remaining life of many financial assets. We plan to adopt this new standard on January 1, 2020. We expect that our adoption of this standard will not have a material impact on our consolidated financial statements.

(13) Commitments and Contingencies

(a) Operating Leases

Rent expense for office space, warehouse facilities and certain corporate equipment for the years ended December 31, 2016, 2015 and 2014 was $3.0 million, $2.9 million and $2.3 million, respectively. Commitments for future minimum lease payments for non-cancelable leases are as follows (in thousands):

2017	$ 1,586
2018	1,443
2019	1,137
2020	99
2021	72
Thereafter	—
Total	$ 4,337

(b) Major Customers

We had revenue from one customer representing 11.6% of total revenue for the year ended December 31, 2014. No other customer represented greater than 10% of revenue for the year ended December 31, 2014.

(c) Litigation

From time to time, we and our subsidiaries may be involved in various claims and litigation arising in the ordinary course of business. In management's opinion, the resolution of such matters is not expected to have a material adverse effect on our consolidated financial position, results of operations or cash flows.

(d) Equipment Purchase Commitments

Our future capital commitments are comprised of binding commitments under purchase orders for new compression units ordered but not received. The commitments as of December 31, 2016 were $17.9 million, all of which are expected to be settled within the next twelve months.

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(e) Sales Tax Contingency

Our compliance with state and local sales tax regulations is subject to audit by various taxing authorities. Certain taxing authorities have claimed that specific operational processes, which we and others in our industry regularly conduct, result in transactions that are subject to state sales taxes. We, and other entities in our industry, have disputed these claims based on existing tax statutes which provide for manufacturing exemptions on the transactions in question. The state taxing authority has indicated that additional documentation to support the manufacturing exemption will be required before it will consider releasing its claim; however, it had not, until very recently, indicated what documentation would be acceptable to them. In response to these recent events, we are in the process of gathering the documentation available to us to support the position we have taken with regard to the disputed transactions. We have recognized a liability of $0.1 million related to this issue; however, we believe it is reasonably possible that we could incur additional losses for this matter depending on whether the taxing authority accepts our documentation as sufficient to support our position that the disputed transactions are not taxable and the impact of any potential resulting litigation. Management estimates that the range of losses we could incur related to this matter is from $0.1 million to approximately $3.0 million. The upper end of this range assumes that we will be unable to apply the manufacturing exemption to any of the transactions in question, which management believes is extremely remote.

(14) Subsequent Events

Phantom Units

On February 10, 2017, an aggregate of 16,293 phantom units (including the corresponding DERs) were granted under the LTIP to the independent directors of our General Partner. The phantom units (including the corresponding DERs) awarded are subject to restrictions on transferability, customary forfeiture provisions and will vest in full on February 15, 2018.

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Supplemental Selected Quarterly Financial Data

(Unaudited)

In the opinion of our management, the summarized quarterly financial data below (in thousands, except per unit amounts) contains all appropriate adjustments, all of which are normally recurring adjustments, considered necessary to present fairly our financial position and the results of operations for the respective periods.

	March 31, 2016	June 30, 2016	September 30, 2016	December 31, 2016
Revenue	$ 66,367	$ 63,511	$ 61,130	$ 74,913
Gross profit (1)	$ 45,538	$ 44,857	$ 42,245	$ 45,120
Net income (loss)	$ 8,538	$ 3,274	$ (2,146)	$ 3,269
Net income (loss) per common unit - basic and diluted	$ 0.24	$ 0.05	$ (0.04)	$ 0.05
Net loss per subordinated unit - basic and diluted	$ (0.38)	$ —	$ —	$ —

	March 31, 2015	June 30, 2015	September 30, 2015	December 31, 2015
Revenue	$ 65,000	$ 66,390	$ 70,540	$ 68,615
Gross profit (1)	$ 45,789	$ 47,311	$ 48,621	$ 47,285
Net income	$ 11,456	$ (15,904)	$ 9,805	$ (159,630)
Net income (loss) per common unit - basic and diluted	$ 0.24	$ (0.34)	$ 0.21	$ (3.02)
Net income (loss) per subordinated unit - basic and diluted	$ 0.24	$ (0.35)	$ 0.16	$ (3.03)

(1) Gross profit is defined as revenue less cost of operations, exclusive of depreciation and amortization expense.

The quarter ended June 30, 2015 included a charge for impairment of compressor equipment of $26.8 million. The quarter ended December 31, 2015 included a charge for impairment of goodwill of $172.2 million.