USA Compression Partners, LP
Form 10-K
February 19, 2019
Table of Contents

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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, 2018

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

100 Congress Avenue, Suite 450 Austin, TX	78701
(Address of Principal Executive Offices)	(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 every Interactive Data File required to be submitted 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 such files). Yes No

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

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

Large accelerated filer	Accelerated filer
Non-accelerated filer	Smaller reporting company

Emerging growth company

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes No

The aggregate market value of common units held by non-affiliates of the registrant as of June 29, 2018, the last business day of the registrant's most recently completed second fiscal quarter was $831,898,973. This calculation does not reflect a determination that such persons are affiliates for any other purpose.

As of February 14, 2019, there were 90,000,504 common units and 6,397,965 Class B Units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE: NONE

Table of Contents

Table of Contents

Table of Contents

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 "if," "outlook," "will," "could," "should," or similar words or the negatives 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 industries specifically;

· competitive conditions in our industry;

· changes in the long-term supply of and demand for crude oil and natural gas;

· our ability to realize the anticipated benefits of acquisitions and to integrate the acquired assets with our existing fleet, including the CDM Acquisition (as defined below);

· actions taken by our customers, competitors and third-party operators;

· the deterioration of the financial condition of our customers;

· changes in the availability and cost of capital;

· operating hazards, natural disasters, weather-related delays, casualty losses and other matters beyond our control;

- the effects of existing and future laws and governmental regulations; 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.

ITEM 1.Business

Following the transactions described in further detail below, CDM Resource Management LLC and CDM Environmental & Technical Services LLC, which together represent the CDM Compression Business (the "USA Compression Predecessor"), has been determined to be the historical predecessor of USA Compression Partners, LP (the "Partnership") for financial reporting purposes. The USA Compression Predecessor is considered the predecessor of the Partnership because Energy Transfer Equity, L.P. ("ETE"), through its wholly owned subsidiary Energy Transfer Partners, L.L.C., controlled the USA Compression Predecessor prior to the transactions described below and obtained control of the Partnership through its acquisition of USA Compression GP, LLC, the general partner of the Partnership (the "General Partner").

Table of Contents

The closing of the Transactions occurred on April 2, 2018 (the "Transactions Date") and has been reflected in the consolidated financial statements of the Partnership.

In October 2018, ETE and Energy Transfer Partners, L.P. ("ETP") completed the merger of ETP with a wholly owned subsidiary of ETE in a unit-for-unit exchange (the "ETE Merger"). Following the closing of the ETE Merger, ETE changed its name to "Energy Transfer LP" and ETP changed its name to "Energy Transfer Operating, L.P." ("ETO"). Upon the closing of the ETE Merger, ETE contributed to ETP 100% of the limited liability company interests in the General Partner. References herein to "ETP" refer to Energy Transfer Partners, L.P. for periods prior to the ETE Merger and ETO following the ETE Merger, and references to "ETE" refer to Energy Transfer Equity, L.P. for periods prior to the ETE Merger and Energy Transfer LP following the ETE Merger.

All references in this report to the USA Compression Predecessor, as well as the terms "our," "we," "us" and "its" refer to the USA Compression Predecessor when used in a historical context or in reference to the periods prior to the Transactions Date, unless the context otherwise requires or where otherwise indicated. All references in this section to the Partnership, as well as the terms "our," "we," "us" and "its" refer to USA Compression Partners, LP, together with its consolidated subsidiaries, including the USA Compression Predecessor, when used in the present or future tense and for periods subsequent to the Transactions Date, unless the context otherwise requires or where otherwise indicated.

Overview

We are a growth-oriented Delaware limited partnership, and we believe that we are one of the largest independent providers of compression services in the United States ("U.S.") in terms of total compression fleet horsepower. USA Compression Partners, LP has been providing compression services since 1998 and completed its initial public offering in January 2013. The USA Compression Predecessor has been providing compression services since 1997 and was a wholly owned indirect subsidiary of ETP prior to the Transactions Date. As of December 31, 2018, we had 3,597,097 horsepower in our fleet and 131,750 horsepower on order for expected delivery during 2019. We provide compression services to our customers primarily in connection with infrastructure applications, including both allowing for the processing and transportation of natural gas through the domestic pipeline system and enhancing crude oil production through artificial lift processes. As such, our compression services play a critical role in the production, processing and transportation of both natural gas and crude oil.

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

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

Table of Contents

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 and maintain high overall utilization rates for our fleet.

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

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

We provide compression services to major oil companies and independent producers, processors, gatherers and transporters of natural gas and crude oil. Regardless of the application for which our services are provided, our customers rely upon the availability of the equipment used to provide compression services and our expertise to maximize the throughput of product, reduce fuel costs and minimize emissions. While we significantly expanded our geographic footprint with our acquisition of the USA Compression Predecessor from ETP (the "CDM Acquisition"), our customers may have compression demands in areas of the U.S. in conjunction with their field development projects where we are not currently operating. We continually consider further expansion of our geographic 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.

We also own and operate a fleet of equipment used to provide natural gas treating services, such as carbon dioxide and hydrogen sulfide removal, natural gas cooling and dehydration, to natural gas producers and midstream companies.

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

Recent Developments

Senior Notes Issuance

On March 23, 2018, USA Compression Partners, LP and its wholly-owned subsidiary, USA Compression Finance Corp., a Delaware corporation ("Finance Corp." and, together with USA Compression Partners, LP, the "Issuers") co-issued $725 million in aggregate principal amount of 6.875% senior notes due 2026 (the "Senior Notes") and entered into an Indenture (the "Indenture"), among the Issuers, the Guarantors (as defined below) and Wells Fargo Bank, National Association, as trustee. The Senior Notes are guaranteed (the "Guarantees"), jointly and severally, on a senior unsecured basis by all of the Partnership's existing subsidiaries (other than Finance Corp.) and will be guaranteed by each of its future restricted subsidiaries that either borrows under, or guarantees, the Credit Agreement (as defined below) or guarantees certain of the Partnership's other indebtedness (collectively, the "Guarantors"). The Senior Notes accrue interest at the rate of 6.875% per year, and interest on the Senior Notes is payable semi-annually in arrears on April 1 and October 1, with the first such payment having occurred on October 1, 2018.

Table of Contents

On January 14, 2019, the Partnership completed an exchange offer whereby holders of the Senior Notes exchanged all of the Senior Notes for an equivalent amount of senior notes registered under the Securities Act of 1933 (the “Exchange Notes”). The Exchange Notes are substantially identical to the Senior Notes, except that the Exchange Notes have been registered with the Securities and Exchange Commission (“SEC”) and do not contain the transfer restrictions, restrictive legends, registration rights or additional interest provisions of the Senior Notes.

The Indenture contains customary terms, events of default and covenants relating to, among other things, the incurrence of debt, the payment of distributions or similar restricted payments, undertaking transactions with affiliates and limitations on asset sales.

CDM Acquisition and Issuance of Class B Units

On the Transactions Date, we completed the CDM Acquisition for aggregate consideration to ETP of approximately $1.7 billion, consisting of (i) 19,191,351 common units, (ii) 6,397,965 Class B units representing limited partner interests in us (the “Class B Units”) and (iii) $1.2 billion in cash (including customary closing adjustments). The Class B Units are a class of partnership interests in the Partnership that have substantially all of the rights and obligations of our common units, except that the Class B Units do not receive any quarterly distributions paid on our common units until the Class B Units automatically convert into common units following the record date attributable to the quarter ending June 30, 2019.

General Partner Purchase Agreement

On the Transactions Date and in connection with the closing of the CDM Acquisition, pursuant to that certain Purchase Agreement, dated as of January 15, 2018, by and among ETE, Energy Transfer Partners, L.L.C. (together with ETE, the “GP Purchasers”), USA Compression Holdings, LLC (“USAC Holdings”) and, solely for certain purposes therein, R/C IV USACP Holdings, L.P. and ETP, the GP Purchasers acquired from USAC Holdings (i) all of the outstanding limited liability company interests in the General Partner and (ii) 12,466,912 common units of the Partnership for cash consideration equal to $250 million. Upon the closing of the ETE Merger, ETE contributed all of the outstanding limited liability company interests in the General Partner and the 12,466,912 common units to ETP.

Equity Restructuring Agreement

On the Transactions Date and in connection with the closing of the CDM Acquisition, we consummated the transactions contemplated by the Equity Restructuring Agreement dated January 15, 2018, by and among us, the General Partner and ETE, including, among other things, the cancellation of the Incentive Distribution Rights (as defined in the Second Amended and Restated Agreement of Limited Partnership of the Partnership (the “Partnership Agreement”)) in the Partnership and conversion of the General Partner’s General Partner Interest (as defined in the Partnership Agreement) into a non-economic general partner interest, in exchange for our issuance of 8,000,000 common units to the General Partner. In addition, at any time after one year following the Transactions Date, ETE has the right to contribute (or cause any of its subsidiaries to contribute) to us all of the outstanding equity interests in any of its subsidiaries that owns the general partner interest in us in exchange for $10 million (the “GP Contribution”); provided that the GP Contribution will occur automatically if at any time following the Transactions Date (i) ETE or one of its subsidiaries (including ETP) owns, directly or indirectly, the general partner interest in us and (ii) ETE and its subsidiaries (including ETP) collectively own less than 12,500,000 of our common units.

Series A Preferred Unit and Warrant Private Placement

On the Transactions Date, we also consummated the transactions contemplated by the Series A Preferred Unit and Warrant Purchase Agreement (the “Purchase Agreement”), dated January 15, 2018, between the Partnership and certain investment funds managed or sub-advised by EIG Global Energy Partners (“EIG”) and FS Energy and Power Fund (collectively, the “Purchasers”), whereby the Partnership issued and sold in a private placement $500 million in the aggregate of (i) newly authorized and established Series A Preferred Units representing limited partner interests in us (the “Preferred Units”) and (ii) two tranches of warrants to purchase our common units (collectively, the “Warrants”). Pursuant to the terms of the Purchase Agreement, on the Transactions Date, we issued (i) 500,000 Preferred Units to the

Table of Contents

Purchasers at a price of $1,000 per Preferred Unit, (ii) Warrants to purchase 5,000,000 common units with a strike price of $17.03 per unit and (iii) Warrants to purchase 10,000,000 common units with a strike price of $19.59 per unit. The Warrants may be exercised by the holders thereof at any time beginning on the one year anniversary of the Transactions Date and before the tenth anniversary of the Transactions Date. Upon exercise of the Warrants, we may, at our option, elect to settle the Warrants in common units on a net basis.

Credit Agreement Amendment and Restatement

On the Transactions Date, we entered into the Sixth Amended and Restated Credit Agreement (the "Credit Agreement") by and among the Partnership, as borrower, USAC OpCo 2, LLC, USAC Leasing 2, LLC, USA Compression Partners, LLC, USAC Leasing, LLC, CDM Resource Management LLC, CDM Environmental & Technical Services LLC and Finance Corp., the lenders party thereto from time to time, JPMorgan Chase Bank, N.A., as agent and an LC issuer, JPMorgan Chase Bank, N.A., Barclays Bank PLC, Regions Capital Markets, a division of Regions Bank, RBC Capital Markets and Wells Fargo Bank, N.A., as joint lead arrangers and joint book runners, Barclays Bank PLC, Regions Bank, RBC Capital Markets and Wells Fargo Bank, N.A., as syndication agents, and MUFG Union Bank, N.A., SunTrust Bank and The Bank of Nova Scotia, as senior managing agents. The Credit Agreement amended and restated that certain Fifth Amended and Restated Credit Agreement, dated as of December 13, 2013, as amended (the "Fifth A&R Credit Agreement").

The Credit Agreement amended the Fifth A&R Credit Agreement to, among other things, (i) increase the borrowing capacity under the Credit Agreement from $1.1 billion to $1.6 billion (subject to availability under a borrowing base), (ii) extend the termination date (and the maturity date of the obligations thereunder) from January 6, 2020 to April 2, 2023, (iii) subject to the terms of the Credit Agreement, permit up to $400 million of future increases in borrowing capacity, (iv) modify the leverage ratio covenant to be 5.75 to 1.0 through the end of the fiscal quarter ending March 31, 2019, 5.5 to 1.0 through the end of the fiscal quarter ending December 31, 2019, and 5.0 to 1.0 thereafter and (v) increase the applicable margin for eurodollar borrowings to range from 2.00% to 2.75%, depending on our leverage ratio, all as more fully set forth in the Credit Agreement. Amounts borrowed and repaid under the Credit Agreement may be re-borrowed. 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.")

Business Strategies

Our principal business objective is to maintain or increase the quarterly cash distributions that we pay to our common 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:

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

· Continue to execute on attractive organic growth opportunities. Prior to the CDM Acquisition, the Partnership grew the horsepower in its fleet of compression units and its compression revenues each at a compound annual growth rate of 15%, which the Partnership executed primarily through organic growth. We believe organic growth opportunities will be a source of near-term growth, which we seek to achieve by (i) increasing our business with existing customers, (ii) obtaining new customers in our existing areas of operations and (iii) expanding our operations into new geographic areas.

· Partner with customers who have significant compression needs. We actively seek to identify customers with meaningful acreage positions or significant infrastructure development in active and growing areas. We work

Table of Contents

with these customers to jointly develop long-term and adaptable solutions designed to optimize their lifecycle compression costs. We believe this is important in determining the overall economics of producing, gathering and transporting natural gas and crude oil. Our proactive and collaborative approach positions us to serve as our customers' compression service provider of choice.

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

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

· Maintain financial flexibility. We intend to maintain financial flexibility to enable us to take advantage of growth opportunities. Historically, we have utilized our cash flow from operations, borrowings under the Credit Agreement 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 debt levels that 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 and 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 compressor frames and cylinders manufactured by Ariel Corporation. Our units can be rapidly and cost effectively modified for specific customer applications. As of December 31, 2018, 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 5,000 horsepower per unit. These larger horsepower units, which we define as 400 horsepower per unit or greater, represented 85.8% of our total fleet horsepower (including compression units on order) as of December 31, 2018. In addition, a portion of our fleet consists of smaller horsepower units ranging from 40 horsepower to 399 horsepower that are primarily used in gas lift applications. We believe the young age and

Table of Contents

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, 2018:

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	528,084	3,101	900	4	528,984	3,105	14.2	%	56.0	%
Large horsepower >400 and <1,000	429,203	735	—	—	429,203	735	11.5	%	13.3	%
>1,000	2,639,810	1,650	130,850	55	2,770,660	1,705	74.3	%	30.7	%
Total	3,597,097	5,486	131,750	59	3,728,847	5,545	100.0	%	100.0	%

(1) As of December 31, 2018, we had 131,750 horsepower on order for delivery during 2019.

The following table sets forth certain information regarding our compression fleet as of the dates and for the periods indicated and excludes certain gas treating assets for which horsepower is not a relevant metric:

	Year Ended December 31,						Percent Change			
Operating Data:	2018		2017 (8)		2016 (8)		2018		2017	
Fleet horsepower (at period end) (1)	3,597,097		1,730,820		1,600,842		107.8	%	8.1	%
Total available horsepower (at period end) (2)	3,675,447		1,780,893		1,606,424		106.4	%	10.9	%
Revenue generating horsepower (at period end) (3)	3,262,470		1,395,328		1,227,899		133.8	%	13.6	%
Average revenue generating horsepower (4)	2,760,029		1,293,864		1,203,487		113.3	%	7.5	%
Revenue generating compression units (at period end)	4,753		2,076		1,789		128.9	%	16.0	%
Average horsepower per revenue generating compression unit (5)	674		681		668		(1.0)	%	1.9	%
Horsepower utilization (6):										
At period end	94.0	%	87.5	%	77.7	%	7.4	%	12.6	%

Average for the period (7)	91.9	%	82.4	%	77.0	%	11.5	%	7.0	%

(1) Fleet horsepower is horsepower for compression units that have been delivered to us (and excludes units on order). As of December 31, 2018, we had 131,750 horsepower on order for delivery during 2019.
(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.
(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 was 90.7%, 80.6% and 76.7% at December 31, 2018, 2017 and 2016, 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 88.0%, 76.9% and 75.9% for the years ended December 31, 2018, 2017 and 2016, respectively.

Table of Contents

(8) Certain historical metrics attributable to the USA Compression Predecessor have been conformed to the Partnership's calculation methodology.

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 2019 where beneficial from an operational 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 that avoids excessive annual maintenance capital expenditures and minimizes the revenue impact of down-time.

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

General Compression Service Contract Terms

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

Term and termination. Our contracts typically have an initial term of between six months and five years, depending on the application and location of the compression unit. After the expiration of the initial 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, 2018, approximately 47% of our compression services on a revenue basis were provided on a month-to-month basis to customers who continue to utilize our services following expiration of the primary term of their contracts with us.

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

Table of Contents

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 impact to 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, applications engineers and field technicians qualify, analyze and scope new compression applications as well as regularly visit our customers to ensure customer satisfaction, determine a customer's needs related to existing services being provided and 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 400 companies in the energy industry, including major integrated oil companies, public and private independent exploration and production companies and midstream companies. Our ten largest customers accounted for approximately 33% and 43% of our revenue for the year ended December 31, 2018 and 2017, 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 Alfa Laval (US) 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 Corp. and Genis Holdings LLC, to package and assemble our compression units. Although we rely primarily on these suppliers, we believe alternative sources for natural gas compression equipment are generally available if needed. However, relying on alternative sources may increase our costs and change the standardized nature of our fleet. We have not experienced any material supply problems to date. Although lead-times for new Caterpillar engines and new Ariel compressor frames have in the past been in excess of one year due to increased demand and supply allocations imposed on equipment packagers and end-users, currently lead-times for such engines and frames are approximately one year or shorter. Please read Part I, Item 1A ("Risk Factors—Risks Related to Our Business—We depend on a limited number of suppliers and are vulnerable to product shortages and price increases, which could have a negative impact on our results of operations").

Competition

The compression services business is highly competitive. Some of our competitors have a broader geographic scope and 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 been materially affected by seasonality, and we do not currently have reason to believe that 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 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, we cannot predict whether our cost of compliance will materially increase in the future. Any changes in, or more stringent enforcement of, existing environmental laws and regulations, or passage of additional

Table of Contents

environmental 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 various state or federal regulatory agencies. Our standard natural gas compression contract provides that the customer is responsible for obtaining air emissions permits and assuming the environmental risks related to site operations. In some instances, our customers may be required to aggregate emissions from a number of different sources on the theory that the different sources should be considered a single source. Any such determinations could have the effect of making projects more costly than our customers expected and could require the installation of more costly emissions controls, which may lead some of our customers not to pursue certain projects.

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

In recent years, the EPA has lowered the National Ambient Air Quality Standards ("NAAQS") for several air pollutants. For example, in 2015, the EPA finalized a rule strengthening the primary and secondary standards for ground level ozone, both of which are 8-hour concentration standards of 70 parts per billion. 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 emissions 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 emissions standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The rules established specific new requirements regarding emissions from compressors and controllers at natural gas processing plants, dehydrators, storage tanks and other production equipment as well as the first federal air standards for natural gas wells that are hydraulically fractured. In June 2016, the EPA took steps to expand on these regulations when it published New Source Performance Standards, known as Subpart OOOOa, that require certain new, modified or reconstructed facilities in the oil and natural gas sector to reduce methane gas and VOC emissions. These Subpart OOOOa standards would expand the 2012 New Source Performance Standards by using certain equipment-specific emissions control practices, requiring additional controls for pneumatic controllers and pumps as well as compressors, and imposing leak detection and repair requirements for natural gas compressor and booster stations. However, the EPA announced in April 2017 that it intended to reconsider certain aspects of the 2016 New Source Performance Standards, and in May 2017, the EPA issued an administrative stay of key provisions of the rule, but was promptly ordered by the D.C. Circuit to implement the rule. The EPA also proposed 60-day and two-year stays of certain provisions in June 2017 and published a Notice of Data Availability in November 2017 seeking comment and providing clarification regarding the agency's legal authority to stay the rule. In March 2018, EPA finalized narrow amendments to the rule, and in October 2018, EPA proposed further reconsideration amendments to the rule. Among other things, these amendments would alter fugitive emissions requirements, monitoring frequencies, and well site pneumatic pump standards.

Depending upon whether EPA finalizes these further amendments, Subpart OOOOa and any additional regulation of air emissions from the oil and gas sector could result in increased expenditures for pollution control equipment, which could impact our customers' operations and negatively impact our business.

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

There can be no assurance that future requirements compelling the installation of more sophisticated emissions 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 ("GHGs"). In recent years, the U.S. Congress has considered legislation to reduce GHG emissions. It presently appears unlikely that comprehensive climate legislation will be passed in the near future, although energy legislation and other initiatives are expected to be proposed that may be relevant to GHG emissions issues. For example, such initiatives could include a carbon tax or cap and trade program. Further, although Congress has not passed such legislation, almost half of the states have begun to address GHG emissions, primarily through the planned development of emissions inventories or regional GHG cap and trade programs. Depending on the particular program, we could be required to control GHG emissions or to purchase and surrender allowances for GHG emissions resulting from our operations.

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

In 2015, the EPA published standards of performance for GHG 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 emissions reduction that the EPA has determined has been adequately demonstrated for each type of unit. The rule also sets limits for stationary natural gas combustion turbines based on the use of natural gas combined cycle technology.

The EPA also promulgated the Clean Power Plan rule (“CPP”), 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 CPP, which will remain in effect throughout the pendency of the appeals process, including at the U.S. Court of Appeals for 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 the courts will ultimately rule on the legality of the CPP. Additionally, in October 2017, the EPA proposed to repeal the CPP, and in August 2018, the EPA proposed the Affordable Clean Energy rule (“ACE”) to

Table of Contents

replace the CPP. If the effort to replace the CPP with the ACE rule is unsuccessful and rules similar to the CPP are upheld to control GHG emissions from electric utility generating units, demand for the oil and natural gas our customers produce may decrease. In addition, the costs of electricity for our operations may also increase, thereby adversely impacting our business.

In addition to the EPA, the Bureau of Land Management ("BLM") has also promulgated rules to regulate hydraulic fracturing. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into the rock formation to stimulate gas production. In 2015, the BLM promulgated new requirements relating to well construction, water management, and chemical disclosure for companies drilling on federal and tribal land, but subsequently finalized a rule in December 2017 rescinding the 2015 rule. This rescission has been challenged and that litigation is ongoing. If this rescission is not upheld, it could increase the costs of operation for our customers who operate on BLM land, and negatively impact our business. Additionally, 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 "Venting Rule"). The Venting Rule requires operators to use certain technologies and equipment to reduce flaring and to periodically inspect their operations for leaks. The Venting Rule also specifies when operators owe the government royalties for flared gas. In December 2017, BLM finalized a decision to delay implementation of key requirements in the Venting Rule for one year. The agency subsequently finalized a rule in September 2018 to revise the 2016 Venting rule (the "Revised Venting Rule") by rescinding certain requirements, such as the requirement to use certain technologies and equipment, as well as the leak detection and repair requirement. The Revised Venting Rule also specifies that BLM will defer to the appropriate State or tribal authorities in determining whether royalties are owed for flared gas. Challenges to the Venting Rule and the Revised Venting Rule are pending in court. If the Revised Venting Rule is not upheld, and the Venting Rule is fully implemented, it could increase the costs of operations for our customers who operate on BLM land, and negatively impact our business.

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

Although it is not currently possible to predict with specificity how any proposed or future GHG legislation, regulation, agreements or initiatives will impact our business, any legislation or regulation of GHG emissions that may be imposed in areas in which we conduct business or on the assets we operate could result in increased compliance or operating 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. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that oil and gas will continue to represent a major share of global energy use through 2040, and other private sector studies project continued growth in demand for the next two decades. However, recent activism directed at shifting funding away from companies with energy-related assets could result in limitations or restrictions on certain sources of funding for the energy sector.

Finally, it should be noted that some scientists have concluded that increasing concentrations of GHG in Earth's atmosphere may produce climate changes that have significant weather-related effects, such as increased frequency and severity of storms, droughts, 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 United States. In any event, our customers assume responsibility under the majority of our standard natural gas compression contracts for obtaining any permits that may be required under the CWA, whether for discharges or developing property by filling wetlands. Considerable legal uncertainty exists surrounding the standard for what constitutes jurisdictional waters and wetlands subject to the protections and requirements of the CWA. A 2015 rulemaking by the EPA that would significantly expand the scope of jurisdictional waters has been enjoined in a significant number of states by various district courts. As a result, while the 2015 rule is currently implemented in some states, in other states, the EPA continues to implement the pre-2015 definition of waters of the United States as determined by the preexisting regulatory definition, the Supreme Court's holding in Rapanos v. United States, and the agency's post-Rapanos guidance. In 2018, the Supreme Court held that challenges to the rule must be heard in district courts before appeals to the circuit courts can be made; litigation is ongoing regarding substantive challenges to the rule. EPA has also proposed two separate rulemakings to repeal and replace the 2015 Rule, both of which are likely to be challenged if finalized. Should the 2015 rule take effect nationwide, or should a different rule expand the jurisdictional reach of the CWA, our customers could face increased costs and delays due to additional permitting and regulatory requirements and possible challenges to permitting decisions.

Safe Drinking Water Act. A significant portion of our customers' natural gas production is developed from unconventional sources that require hydraulic fracturing as part of the completion process. Legislation to amend the Safe Drinking Water Act ("SDWA") to repeal the exemption for hydraulic fracturing from the definition of "underground injection" and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, have been proposed and the U.S. Congress continues to consider legislation to amend the SDWA. Scrutiny of hydraulic fracturing activities continues in other ways, with the EPA having commenced a multi-year study of the potential environmental impacts of hydraulic fracturing. In December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources "under some circumstances," noting that the following hydraulic fracturing water cycle activities and local- or regional-scale factors are more likely than others to result in more frequent or more severe impacts: water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits. The EPA has also announced that it believes hydraulic fracturing using fluids containing diesel fuel can be regulated under the SDWA notwithstanding the SDWA's general exemption for hydraulic fracturing. Several states have also proposed or adopted legislative or regulatory restrictions on hydraulic fracturing, including prohibitions on the practice. We cannot predict the future of such legislation and what additional, if any, provisions would be included. If additional levels of regulation, restrictions and permits were required through the adoption of new laws and regulations at the federal or state level or if the agencies that issue the permits develop new interpretations of those requirements, that could lead to delays, increased operating costs and process prohibitions that could reduce demand for our compression services, which could 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 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 Services, LLC (“USAC Management”), a wholly owned subsidiary of the 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, 2018, USAC Management had 864 full time employees. None of our employees are subject to collective bargaining agreements. We consider our employee relations to be good.

Available Information

Our website address is usacompression.com. We make available, free of charge at the “Investor Relations” section 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 SEC maintains a website that contains these reports at sec.gov.

Table of Contents

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 materialize, 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 increase the level of such distributions in the future, 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 the General Partner, to enable us to make cash distributions on our common units at the current level.

In order to make cash distributions at our current distribution rate of $0.525 per common unit per quarter, or $2.10 per common unit per year, we will require available cash of $47.2 million per quarter, or $189.0 million per year, based on the number of common units outstanding as of February 14, 2019. In addition, each Class B Unit will automatically convert to one common unit of the Partnership following the record date attributable to the quarter ending June 30, 2019. Distributions on the newly converted Class B Units will require additional available cash of $3.4 million per quarter, or $13.4 million per year at our current distribution rate.

Furthermore, the Partnership Agreement prohibits us from paying distributions on our common units unless we have first paid the quarterly distribution on the Preferred Units, including any previously accrued but unpaid distributions on the Preferred Units. The Preferred Unit distributions require $12.2 million quarterly, or $48.8 million annually, based on the number of Preferred Units outstanding and the distribution rate of $24.375 per Preferred Unit per quarter, or $97.50 per Preferred Unit per year.

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 regions 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 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 the Credit Agreement or the Indenture governing the Senior Notes;
- the cost of acquisitions;
- fluctuations in interest rates;
- the financial condition of our customers;
- our ability to borrow funds and access the capital markets; and
- the amount of cash reserves established by the General Partner.

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

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

In particular, lower natural gas or crude oil prices over the long term could result in a decline in the production of natural gas or crude oil, respectively, resulting in reduced demand for our compression services. For example, the North American rig count, as measured by Baker Hughes, hit a 2014 peak of 1,931 rigs on September 12, 2014, and at that time, Henry Hub natural gas spot prices were $3.82 per MMBtu and West Texas Intermediate ("WTI") crude oil spot prices were $92.18 per barrel. By contrast, the North American rig count hit a modern low of 404 rigs on May 20, 2016, and at that time, Henry Hub natural gas spot prices were $1.81 per MMBtu and WTI crude oil spot prices were $47.67 per barrel. This slowdown in new drilling activity caused some pressure on service rates for new and existing services and contributed to a decline in our utilization during 2015 and into 2016. By the end of December 2018, the North American rig count was 1,083 rigs, the price of WTI crude oil was $45.15 per barrel and Henry Hub natural gas spot prices were $3.25 per MMBtu. Although commodity prices and our utilization generally increased during 2016, 2017 and 2018, the increased activity resulting from such increased commodity prices may not continue. In addition, a small portion of our fleet is used in gas lift applications in connection with crude oil production using horizontal drilling techniques. During the period of low crude oil prices, we experienced pressure on service rates from our customers in gas lift applications; if commodity prices decline from current levels, we may again experience pressure on service rates.

Additionally, an increasing percentage of natural gas and crude oil production comes from unconventional sources, such as shales, tight sands and coalbeds. Such sources can be less economically feasible to produce in low commodity price environments, in part due to costs related to compression requirements, and a reduction in demand for natural gas or gas lift for crude oil may cause such sources of natural gas or crude oil to become 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 the 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

Table of Contents

ten largest customers accounted for approximately 33% and 43% of our revenue for the years ended December 31, 2018 and 2017, 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 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 their 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.

We are exposed to counterparty credit risk. Nonpayment and nonperformance by our customers, suppliers or vendors could reduce our revenues, increase our expenses and otherwise have a negative impact on our ability to conduct our business, operating results, cash flows and ability to make distributions to our unitholders.

Weak economic conditions and widespread financial distress could reduce the liquidity of our customers, suppliers or vendors, making it more difficult for them to meet their obligations to us. We are therefore subject to risks of loss resulting from nonpayment or nonperformance by our customers. Severe financial problems encountered by our customers could limit our ability to collect amounts owed to us, or to enforce the performance of obligations owed to us under contractual arrangements. In the event that any of our customers was to enter into bankruptcy, we could lose all or a portion of the amounts owed to us by such customer, and we may be forced to cancel all or a portion of our service contracts with such customer at significant expense to us.

In addition, nonperformance by suppliers or vendors who have committed to provide us with critical products or services could raise our costs or interfere with our ability to successfully conduct our business.

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

The natural gas compression business is highly competitive. Some of our competitors have a broader geographic scope and 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, which 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 cash available for distribution.

Our customers may choose to vertically integrate their operations by purchasing and operating their own compression fleet, increasing the number 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

Table of Contents

decreased demand for our compression services, which may have a material adverse effect on our business, results of operations, financial condition and reduce our cash available for distribution.

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

Our contracts typically have an initial term of between six months and five years, depending on the application and location of the compression unit. After the expiration of the initial 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, 2018, approximately 47% of our compression services on a revenue basis were provided on a month-to-month basis to customers who continue to utilize our services following expiration of the primary term of their contracts. 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.

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 the level of distributions to our common unitholders.

A principal focus of our strategy is to increase our per common unit distribution 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 the level of distributions on our common units, in which event the market price of our common units will likely decline.

We may be unable to grow successfully through acquisitions, which may negatively impact our operations and limit our ability to maintain or increase the level of distributions on our common units.

From time to time, we may choose to make business acquisitions, such as the CDM Acquisition, to pursue market opportunities, increase our existing capabilities and expand into new geographic 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.

Any acquisitions we do complete may require us to issue a substantial amount of equity or incur a substantial amount of indebtedness. If we consummate any future material acquisitions, our capitalization may change significantly,

Table of Contents

and unitholders will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in connection with any future acquisition. Furthermore, competition for acquisition opportunities may escalate, increasing our costs of pursuing acquisitions or causing us to refrain from making acquisitions.

Also, our reviews of proposed business or asset acquisitions are inherently imperfect because it is generally not feasible to perform an in-depth review of each such proposal given time constraints imposed by sellers. Even if performed, a detailed review of assets and businesses may not reveal existing or potential problems, and may not provide sufficient familiarity with such business or assets to fully assess their deficiencies and potential. Inspections may not be performed on every asset, and environmental problems, such as groundwater contamination, may not be observable even when an inspection is undertaken.

Integration of assets acquired in past acquisitions or future acquisitions with our existing business can be a complex, time-consuming and costly process, particularly in the case of material acquisitions such as the CDM Acquisition, which significantly increased our size and expanded the geographic areas in which we operate. A failure to successfully integrate the acquired assets with our existing business in a timely manner may have a material adverse effect on our business, financial condition, results of operations or cash available for distribution to our unitholders.

The difficulties of integrating past and future acquisitions with our business include, among other things:

· operating a larger combined organization in new geographic areas and new lines of business;

· hiring, training or retaining qualified personnel to manage and operate our growing business and assets;

· integrating management teams and employees into existing operations and establishing effective communication and information exchange with such management teams and employees;

· diversion of management’s attention from our existing business;

· assimilation of acquired assets and operations, including additional regulatory programs;

· loss of customers;

· loss of key employees;

· maintaining an effective system of internal controls in compliance with the Sarbanes-Oxley Act of 2002 as well as other regulatory compliance and corporate governance matters; and

· integrating new technology systems for financial reporting.

If any of these risks or other unanticipated liabilities or costs were to materialize, we may not realize the desired benefits from past and future acquisitions, resulting in a negative impact on our results of operations. For example, subsequent to the CDM Acquisition the attrition rate of specialized field technicians exceeded our projections and, as a result, we incurred unanticipated costs to utilize third-party contractors to service our compression units at a greater cost than we would have incurred to compensate employees to perform the same work.

We may not be successful in integrating acquisitions, including the CDM Acquisition, into our existing operations within our anticipated timeframe, which may result in unforeseen operational difficulties or diminished financial performance or require a disproportionate amount of our management's attention. In addition, acquired assets may perform at levels below the forecasts used to evaluate their acquisition, due to factors beyond our control. If the acquired assets perform at levels below the forecasts, then our future results of operations could be negatively impacted.

Table of Contents

Our ability to fund purchases of additional compression units and complete acquisitions in the future is dependent on our ability to access external expansion capital.

The Partnership Agreement requires us to distribute all of our available cash to our unitholders (excluding prudent operating reserves). We expect that we will rely primarily upon cash generated by operating activities and, where necessary, borrowings under the Credit Agreement 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 through external sources, our ability to maintain or increase the level of distributions on our common units could be significantly impaired. In addition, because we distribute all of our available cash, excluding prudent operating reserves, we may not grow as quickly as businesses that are able to reinvest their available cash to expand ongoing operations.

There are no limitations in the Partnership Agreement on our ability to issue additional equity securities, including securities ranking senior to the common units, subject to certain restrictions in the Partnership Agreement limiting our ability to issue units senior to or pari passu with the Preferred Units. To the extent we issue additional equity securities, including common units and preferred units, the payment of distributions on those additional securities may increase the risk that we will be unable to maintain or increase our per common unit distribution level. Similarly, our incurrence of borrowings or other debt to finance our growth strategy would increase our interest expense, which in turn would decrease our cash available for distribution.

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

The Credit Agreement is a $1.6 billion revolving credit facility that matures in April 2023. In addition, we have the option to increase the amount of total commitments under the Credit Agreement by up to $400.0 million, subject to receipt of lender commitments and satisfaction of other conditions. As of December 31, 2018, we had outstanding borrowings under the Credit Agreement of $1.1 billion and a leverage ratio of 4.33x, borrowing base availability (based on our borrowing base) of $550.5 million and, subject to compliance with the applicable financial covenants, available borrowing capacity under the Credit Agreement of $550.5 million. Financial covenants in the Credit Agreement permit a maximum leverage ratio of (A) 5.75 to 1.0 through the end of the fiscal quarter ending March 31, 2019, (B) 5.50 to 1.0 through the end of the fiscal quarter ending December 31, 2019 and (C) 5.00 to 1.0 thereafter. As of February 14, 2019, we had outstanding borrowings under the Credit Agreement of $1.1 billion.

Our ability to incur additional debt is also subject to limitations in the Credit Agreement, including certain financial covenants. Our level of debt could have important consequences to us, including the following:

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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.

Additionally, in March 2018, the Issuers co-issued $725.0 million of Senior Notes. The Senior Notes mature in 2026 and accrue interest at the rate of 6.875% per year. Interest on the Senior Notes is payable semiannually in arrears on April 1 and October 1.

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 Credit Agreement could be impacted by market interest rates, as all of our outstanding borrowings under the Credit Agreement are subject to variable interest rates that fluctuate with changes in market interest rates. A substantial increase in the interest rates

Table of Contents

applicable to our outstanding borrowings could have a material negative 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 the level of distributions on our common units, curtailing 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.

The terms of the Credit Agreement and the Indenture restrict our current and future operations, particularly our ability to respond to changes or to take certain actions, may limit our ability to pay distributions and may limit our ability to capitalize on acquisitions and other business opportunities.

The Credit Agreement and the Indenture governing the Senior Notes contain a number of restrictive covenants that impose significant operating and financial restrictions on us and may limit our ability to engage in acts that may be in our long-term best interest, including restrictions on our ability to:

· incur additional indebtedness;

· pay dividends or make other distributions or repurchase or redeem equity interests;

· prepay, redeem or repurchase certain debt;

· issue certain preferred units or similar equity securities;

· make investments;

· sell assets;

· incur liens;

· enter into transactions with affiliates;

· alter the businesses we conduct;

· enter into agreements restricting our subsidiaries’ ability to pay dividends; and

- consolidate, merge or sell all or substantially all of our assets.

In addition, the Credit Agreement contains certain operating and financial covenants and requires us to maintain specified financial ratios and satisfy other financial condition tests. Our ability to comply with those covenants and meet those financial ratios and tests can be affected by events beyond our control, including prevailing economic, financial and industry conditions. If market or other conditions deteriorate, our ability to comply with these covenants may be impaired.

A breach of the covenants or restrictions under the Credit Agreement or the Indenture could result in an event of default, in which case a significant portion of our indebtedness may become immediately due and payable and any other debt to which a cross-acceleration or cross-default provision applies may also be accelerated, 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. If we were unable to repay amounts due and payable under the Credit Agreement, those lenders could proceed against the collateral securing that indebtedness. We may not be able to replace the Credit Agreement, or if we are, any subsequent replacement of the Credit Agreement or any new indebtedness could be equally or more restrictive.

These restrictions may negatively affect our ability to grow in accordance with our strategy. In addition, our financial results, substantial indebtedness and credit ratings could adversely affect the availability and terms of our

Table of Contents

financing. Please read Part II, Item 7 (“Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Revolving Credit Facility and— Senior Notes”).

The Preferred Units have rights, preferences and privileges that are not held by, and are preferential to the rights of, holders of our common units.

The Preferred Units rank senior to all of our other classes or series of equity securities with respect to distribution rights and rights upon liquidation. These preferences could adversely affect the market price for our common units, or could make it more difficult for us to sell our common units in the future.

In addition, distributions on the Preferred Units accrue and are cumulative, at the rate of 9.75% per annum on the original issue price, which amounts to a quarterly distribution of $24.375 per Preferred Unit. If we do not pay the required distributions on the Preferred Units, we will be unable to pay distributions on our common units. Additionally, because distributions on the Preferred Units are cumulative, we will have to pay all unpaid accumulated distributions on the Preferred Units before we can pay any distributions on our common units. Also, because distributions on our common units are not cumulative, if we do not pay distributions on our common units with respect to any quarter, our common unitholders will not be entitled to receive distributions covering any prior periods if we later recommence paying distributions on our common units.

The Preferred Units are convertible into common units by the holders of the Preferred Units or by us in certain circumstances. Our obligation to pay distributions on the Preferred Units, or on the common units issued following the conversion of the Preferred Units, could impact our liquidity and reduce the amount of cash flow available for working capital, capital expenditures, growth opportunities, acquisitions, and other general Partnership purposes. Our obligations to the holders of the Preferred Units could also limit our ability to obtain additional financing or increase our borrowing costs, which could have an adverse effect on our financial condition. See Note 11 to our consolidated financial statements.

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

The operating and financial restrictions and covenants in the Partnership Agreement related to the Preferred Units could restrict our ability to finance future operations or capital needs or to expand or pursue our business activities. The Partnership Agreement restricts or limits our ability (subject to certain exceptions) to:

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pay distributions on any junior securities, including our common units, prior to paying the quarterly distribution payable to the holders of the Preferred Units, including any previously accrued and unpaid distributions;

· issue any securities that rank senior to or pari passu with the Preferred Units; however, we will be able to issue an unlimited number of securities ranking junior to the Preferred Units, including junior preferred units and additional common units; and

· incur Indebtedness (as defined in the Credit Agreement) if, after giving pro forma effect to such incurrence, the Leverage Ratio (as defined in the Credit Agreement) determined as of the last day of the most recently ended fiscal quarter would exceed 6.5x, subject to certain exceptions.

A prolonged downturn in the economic environment could cause an impairment of goodwill or other intangible assets and reduce our earnings.

We have recorded $619.4 million of goodwill and $392.6 million of other intangible assets as of December 31, 2018. 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. For example, for the year ended December 31, 2017, the USA Compression Predecessor recognized a $223.0 million impairment of goodwill (see Note 7 to our consolidated financial statements).

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

We have a significant number of long-lived assets on our consolidated balance sheet. Under GAAP, we are required to review our long-lived assets for impairment when events or circumstances indicate that the carrying value of such assets may not be recoverable or such assets 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 a reduction in our expected long-term profitability. For example, during the fiscal year ended December 31, 2018, we evaluated the future deployment of our idle fleet under then-current market conditions and determined to retire and re-utilize key components of 103 compressor units, or approximately 33,000 horsepower, that were previously used to provide services in our business. As a result, we recognized impairments of $8.7 million during the year ended December 31, 2018. The USA Compression Predecessor did not recognize any impairment of long-lived assets during the years ended December 31, 2017 or 2016.

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

We depend on the continuing efforts of our executive officers and 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 favorable, the competition for experienced operational and field technicians increases as other energy and manufacturing companies’ needs for the same personnel increases. Our ability to grow or even to continue our current level of service to our current customers could be adversely impacted if we are unable to successfully hire, train and retain these important personnel.

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

The substantial majority of the components for our natural gas compression equipment are supplied by Caterpillar Inc., Cummins Inc. and Arrow Engine Company for engines, Air-X-Changers and Alfa Laval (US) for coolers, and Ariel Corporation, GE Oil & Gas Gemini products and Arrow Engine Company for compressor frames and cylinders. Our reliance on these suppliers involves several risks, including price increases and a potential inability to obtain an adequate supply of required components in a timely manner. We also rely primarily on four vendors, A G Equipment Company, Alegacy Equipment, LLC, Standard Equipment Corp. and Genis Holdings LLC, 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 compression units to us.

Table of Contents

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, emissions controls and other environmental protection and occupational health and safety concerns, as discussed in detail in Item 1 ("Business—Our Operations—Environmental and Safety Regulations"). Environmental laws and regulations may, in certain circumstances, impose strict liability for environmental contamination, which may render us liable for remediation costs, natural resource damages and other damages as a result of our conduct that was lawful at the time it occurred or the conduct of, or conditions caused by, prior owners or operators or other third parties. In addition, where contamination may be present, it is not uncommon for neighboring land owners and other third parties to file claims for personal injury, property damage and recovery of 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 emissions limits. Given the wide variety of locations in which we operate, and the numerous environmental permits and other authorizations that are applicable to our operations, we may occasionally identify or be notified of technical violations of certain requirements existing under various permits or other authorizations. We could be subject to penalties for any noncompliance in the future.

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

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

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

New regulations or proposed modifications to existing regulations under the Clean Air Act ("CAA"), as discussed in detail in Item 1 ("Business—Our Operations—Environmental and Safety Regulations"), may lead to adverse impacts on our business, financial condition, results of operations, and cash available for distribution. For example, in 2015, the EPA finalized a rule strengthening the primary and secondary National Ambient Air Quality Standards ("NAAQS") for ground level ozone, both of which are 8-hour concentration standards of 70 parts per billion. 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 negatively impact our customers' operations, increase the cost of additions to property, plant, and equipment, and negatively impact our business.

Table of Contents

In 2012, the EPA finalized rules that establish new air emissions 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 emissions standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The rules established specific new requirements regarding emissions from compressors and controllers at natural gas processing plants, dehydrators, storage tanks and other production equipment as well as the first federal air standards for natural gas wells that are hydraulically fractured. In June 2016, the EPA took steps to expand on these regulations when it published New Source Performance Standards, known as Subpart OOOOa, that require certain new, modified or reconstructed facilities in the oil and natural gas sector to reduce methane gas and VOC emissions. These Subpart OOOOa standards would expand the 2012 New Source Performance Standards by using certain equipment-specific emissions control practices, requiring additional controls for pneumatic controllers and pumps as well as compressors, and imposing leak detection and repair requirements for natural gas compressor and booster stations. However, the EPA announced in April 2017 that it intended to reconsider certain aspects of the 2016 New Source Performance Standards, and in May 2017, the EPA issued an administrative stay of key provisions of the rule, but was promptly ordered by the D.C. Circuit to implement the rule. The EPA also proposed 60-day and two-year stays of certain provisions in June 2017 and published a Notice of Data Availability in November 2017 seeking comment and providing clarification regarding the agency's legal authority to stay the rule. In March 2018, the EPA finalized narrow amendments to the rule, and in October 2018, the EPA proposed further reconsideration amendments to the rule. Among other things, these amendments would alter fugitive emissions requirements, monitoring frequencies and well site pneumatic pump standards.

Depending on whether the EPA finalizes these further amendments, Subpart OOOOa and any additional regulation of air emissions from the oil and gas sector could result in increased expenditures for pollution control equipment, which could impact our customers' operations and negatively impact our business.

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

Climate change continues to attract considerable public and scientific attention. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of natural gas, are examples of greenhouse gases ("GHGs"). In recent years, the U.S. Congress has considered legislation to reduce GHG emissions. It presently appears unlikely that comprehensive climate legislation will be passed in the near future, although energy legislation and other initiatives are expected to be proposed that may be relevant to GHG emissions issues. For example, such initiatives could include a carbon tax or cap and trade program. Further, although Congress has not passed such legislation, almost half of the states have begun to address GHG emissions, primarily through the planned development of emissions inventories or regional GHG cap and trade programs. Depending on the particular program, we could be required to control GHG emissions or to purchase and surrender allowances for GHG emissions resulting from our operations.

Independent of Congress, and as discussed in detail in Item 1 ("Business—Our Operations—Environmental and Safety Regulations"), the EPA undertook to adopt regulations controlling GHG emissions under its existing CAA authority. For example, in 2015, the EPA published standards of performance for GHG 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 emissions reduction that the EPA has determined has been adequately demonstrated for each type of unit. The rule also sets limits for stationary natural gas combustion turbines based on the use of natural gas combined cycle technology. The EPA also promulgated the Clean Power Plan rule (“CPP”), 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 CPP, which will remain in effect throughout the pendency of the appeals process, including at the United States Court of Appeals for 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 the courts will ultimately rule on the legality of the CPP. Additionally, in October 2017, the EPA proposed to repeal the CPP, and in August 2018, the EPA proposed the Affordable Clean Energy rule (“ACE”) to replace the CPP. If the effort to replace the CPP with the ACE is unsuccessful and rules similar to the CPP are upheld to control GHG emissions from electric utility generating units, demand for the oil and natural gas our customers produce may decrease.

Table of Contents

Although it is not currently possible to predict with specificity how any proposed or future GHG legislation, regulation, agreements or initiatives will impact our business, any legislation or regulation of GHG emissions that may be imposed in areas in which we conduct business or on the assets we operate could result in increased compliance or operating 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 Earth's atmosphere may produce climate changes that have significant weather-related effects, such as increased frequency and severity of storms, droughts, floods and other climatic events. If any of those effects were to occur, they could have an adverse effect on our assets and operations. Also, recent activism directed at shifting funding away from companies with energy-related assets could result in a reduction of funding for the energy sector overall, which could have an adverse effect on our ability to obtain external financing.

Increased regulation of hydraulic fracturing could result in reductions of, 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 rock formation to stimulate gas production. Legislation to amend the Safe Drinking Water Act ("SDWA") to repeal the exemption for hydraulic fracturing from the definition of "underground injection" and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, have been proposed and the U.S. Congress continues to consider legislation to amend the SDWA. Scrutiny of hydraulic fracturing activities continues in other ways, with the EPA having commenced a multi-year study of the potential environmental impacts of hydraulic fracturing. In December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources "under some circumstances," noting that the following hydraulic fracturing water cycle activities and local- or regional-scale factors are more likely than others to result in more frequent or more severe impacts: water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits.

In addition to the EPA, the Bureau of Land Management ("BLM") has also promulgated rules to regulate hydraulic fracturing. In 2015, the BLM promulgated new requirements relating to well construction, water management, and chemical disclosure for companies drilling on federal and tribal land, but subsequently finalized a rule in December 2017 rescinding the 2015 rule. This rescission has been challenged, and that litigation is ongoing. If this rescission is not upheld, it could increase the costs of operation for our customers who operate on BLM land, and negatively impact our business. Additionally, 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 Venting Rule requires operators to use certain technologies and equipment to reduce flaring and to periodically inspect their operations for leaks. The Venting Rule also specifies when operators owe the government royalties for flared gas. In December 2017, BLM finalized a decision to delay implementation of key requirements in the Venting Rule for one year. The agency subsequently finalized a rule in September 2018 to revise the 2016 Venting rule by rescinding certain requirements, such as the requirement to use certain technologies and equipment, as well as the leak detection and repair requirement. The Revised Venting Rule also specifies that the BLM will defer to the appropriate State or tribal authorities in determining whether royalties are owed for flared gas. Challenges to the Venting Rule and the Revised Venting Rule are pending in court. If the Revised Venting Rule is not upheld, and the Venting Rule is fully implemented, it could increase the costs of operations for our customers who operate on BLM land, and in turn negatively impact our business.

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

We cannot predict the future of any such legislation or tort liability. If additional levels of regulation, restrictions and permits were required through the adoption of new laws and regulations at the federal or state level or the development of new interpretations of those requirements by the agencies that issue the required permits, that could lead to operational 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.

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

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

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, malfunctions 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.

Cybersecurity breaches and other disruptions of our information systems could compromise our information and operations and expose us to liability, which would cause our business and reputation to suffer.

We rely on our information technology infrastructure to process, transmit and store electronic information critical to our business activities. In recent years, there has been a rise in the number of cyberattacks on other companies' network and information systems by both state-sponsored and criminal organizations, and as a result, the risks associated with such an event continue to increase. A significant failure, compromise, breach or interruption of our information systems could result in a disruption of our operations, customer dissatisfaction, damage to our reputation, a loss of customers or revenues and potential regulatory fines. If any such failure, interruption or similar event results in improper disclosure of information maintained in our information systems and networks or those of our customers, suppliers or vendors, including personnel, customer, pricing and other sensitive information, we could also be subject to liability under relevant contractual obligations and laws and regulations protecting personal data and privacy. Our financial results could also be adversely affected if our information systems are breached or an employee causes our information systems to fail, either as a result of inadvertent error or by deliberately tampering with or manipulating such systems.

Table of Contents

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 insurance against such attacks 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 resulting from terrorism or war could also negatively 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 common units.

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and to operate successfully as a publicly traded partnership. Although we continuously 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 to, among other things, review and report annually on the effectiveness of our internal control over financial reporting. In addition, our independent registered public accountants are now required to assess the effectiveness of our internal control over financial reporting since we ceased to be an emerging growth company under the Jumpstart Our Business Startups Act (the “JOBS Act”) on December 31, 2018, which means that we will no longer benefit from the reduced reporting requirements afforded to emerging growth companies under the JOBS Act.

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 may result in 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 common units.

Risks Inherent in an Investment in Us

Holders of our common units have limited voting rights and are not entitled to elect the General Partner or its directors.

Unlike the holders of common stock in a corporation, our common unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Common unitholders have no right to elect the General Partner or the board of directors of the General Partner (the "Board"). ETO is the sole member of the General Partner and has the right to appoint the majority of the members of the Board, including all but one of its independent directors. Also, pursuant to that certain Board Representation Agreement entered into by us, the General Partner, ETE and EIG Veteran Equity Aggregator, L.P. (along with its affiliated funds, "EIG") in connection with our private placement of Preferred Units and Warrants to EIG, EIG Management Company, LLC has the right to designate one of the members of the Board for so long as the holders of the Preferred Units hold more than 5% of the Partnership's outstanding common units in the aggregate (taking into account the common units that would be issuable upon conversion of the Preferred Units and exercise of the Warrants).

If our common unitholders are dissatisfied with the General Partner's performance, they have little ability to remove the General Partner. As a result of these limitations, the price of our common units may decline because of the absence or reduction of a takeover premium in the trading price. Furthermore, the Partnership Agreement contains provisions

Table of Contents

limiting the ability of common unitholders to call meetings or to obtain information about our operations, as well as other provisions limiting our common unitholders' ability to influence the manner or direction of management.

ETO owns and controls the General Partner, and the General Partner has sole responsibility for conducting our business and managing our operations. The General Partner and its affiliates, including ETO, 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.

ETO owns and controls the General Partner and appointed all of the officers and a majority of the directors of the General Partner, some of whom are also officers and directors of ETO. Although the 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 the General Partner also have a fiduciary duty to manage the General Partner in a manner that is beneficial to its owner. Conflicts of interest will arise between the General Partner and its owner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, the General Partner may favor its own interests and the interests of its owner over our interests and the interests of our unitholders. These conflicts include the following situations, among others:

- neither the Partnership Agreement nor any other agreement requires ETO to pursue a business strategy that favors us;

- ETO and its affiliates are not prohibited from engaging in businesses or activities that are in direct competition with us or from offering business opportunities or selling assets to our competitors;

- the General Partner is allowed to take into account the interests of parties other than us, such as its owner, in resolving conflicts of interest;

- the Partnership Agreement limits the liability of and reduces the fiduciary duties owed by the 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, the General Partner has the power and authority to conduct our business without unitholder approval;

- the 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;

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the 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;

- the General Partner determines which costs it incurs are reimbursable by us;

- the General Partner may cause us to borrow funds in order to permit the payment of cash distributions;

- the 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;

- the Partnership Agreement does not restrict the 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;

Table of Contents

- the General Partner currently limits, and intends to continue limiting, its liability for our contractual and other obligations;
- the General Partner may exercise its right to call and purchase all of our common units not owned by it and its affiliates if together those entities at any time own more than 80% of our common units;
- the General Partner controls the enforcement of the obligations that it and its affiliates owe to us; and
- the General Partner decides whether to retain separate counsel, accountants or others to perform services for us.

The General Partner's liability for our obligations is limited.

The 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 the General Partner or its assets. The General Partner may therefore cause us to incur indebtedness or other obligations that are nonrecourse to it. The Partnership Agreement provides that any action taken by the General Partner to limit its liability is not a breach of the General Partner's fiduciary duties, even if we could have obtained more favorable terms without such limitation on liability. In addition, we are obligated to reimburse or indemnify the General Partner to the extent that it incurs obligations on our behalf. Any such reimbursement or indemnification payments would reduce our amount of cash otherwise available for distribution.

The Partnership Agreement limits the General Partner's fiduciary duties to our unitholders.

The Partnership Agreement contains provisions that modify and reduce the fiduciary standards to which the General Partner would otherwise be held by state fiduciary duty law. For example, the Partnership Agreement permits the General Partner to make a number of decisions in its individual capacity, as opposed to its capacity as the General Partner, or otherwise free of fiduciary duties to us and our unitholders. This entitles the 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 the 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 common units it owns; 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 of the Partnership Agreement, including the provisions discussed above.

Even if holders of our common units are dissatisfied, they currently cannot remove the General Partner without ETO's consent.

Common unitholders are currently unable to remove the General Partner because the General Partner and its affiliates own sufficient number of our common units to prevent its removal. The vote of the holders of at least 662/3% of all outstanding common units is required to remove the General Partner, and ETO currently owns over 331/3% of our outstanding common units.

Table of Contents

The Partnership Agreement restricts the remedies available to holders of our common units for actions taken by the General Partner that might otherwise constitute breaches of fiduciary duty.

The Partnership Agreement contains provisions that restrict the remedies available to common unitholders for actions taken by the General Partner that might otherwise constitute breaches of fiduciary duty under state fiduciary duty law. For example, the Partnership Agreement:

· provides that whenever the General Partner makes a determination or takes, or declines to take, any other action in its capacity as the General Partner, the 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 the Partnership Agreement, Delaware law, or any other law, rule or regulation, or at equity;

· provides that the General Partner will not have any liability to us or our unitholders for decisions made in its capacity as 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 the Partnership;

· provides that the 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 the 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 the 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, although the General Partner is not obligated to seek such approval;

(b) approved by the vote of a majority of our outstanding common units, excluding any common units owned by the 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 a situation involving a transaction with an affiliate or a conflict of interest, any determination by the 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 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) or (d) above, then it will conclusively be deemed that, in making its decision, the Board acted in good faith.

The Partnership Agreement restricts the voting rights of unitholders owning 20% or more of our common units.

Common unitholders' voting rights are further restricted by a provision of the Partnership Agreement providing that any units held by a person or group that owns 20% or more of such class of units then outstanding, other than, with respect to our common units, the General Partner, its affiliates, their direct transferees and their indirect transferees approved by the General Partner (which approval may be granted in its sole discretion) and persons who acquired such common units with the prior approval of the General Partner, cannot vote on any matter.

Table of Contents

The general partner interest or the control of the General Partner may be transferred to a third party without unitholder consent.

The 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 common unitholders. Furthermore, the Partnership Agreement does not restrict the ability of ETO to transfer all or a portion of its ownership interest in the General Partner to a third party. The new owner of the General Partner would then be in a position to replace the majority of the Board, and all of the officers, of the General Partner with its own designees and thereby exert significant control over the decisions made by the Board and the officers of the General Partner.

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

The market price of master limited partnership units, like other yield-oriented securities, may be affected by, among other factors, implied distribution yield. The distribution yield is often used by investors to compare and rank yield-oriented securities for investment decision-making purposes. Therefore, increases or decreases in interest rates may affect whether or not certain investors decide to invest in master limited partnership units, including ours, and a rising interest rate environment could have an adverse impact on our common unit price and impair our ability to issue additional equity or incur debt to fund growth or for other purposes, including distributions.

We may issue additional limited partner interests without the approval of the common unitholders, which would dilute the common unitholders' existing ownership interests and may increase the risk that we will not have sufficient available cash to maintain or increase our per common unit distribution level.

The Partnership Agreement does not limit the number or timing of additional limited partner interests that we may issue, including limited partner interests that are convertible into our common units, without the approval of our common unitholders. Also, for the first four full calendar quarters following the Transactions Date, we are permitted to pay a portion of the quarterly distribution on the Preferred Units with additional Preferred Units, and the Preferred Units are convertible into common units in the future at the option of the holders of the Preferred Units, or under certain circumstances, at our option.

If a substantial portion of the Preferred Units are converted into common units, common unitholders could experience significant dilution. Furthermore, if holders of such converted Preferred Units were to dispose of a substantial portion of these common units in the public market, whether in a single transaction or series of transactions, it could adversely affect the market price of our common units. In addition, these sales, or the possibility that these sales may occur, could make it more difficult for us to sell our common units in the future.

Our issuance of additional common units, including pursuant to our Distribution Reinvestment Plan (“DRIP”), or other equity securities of equal or senior rank, such as additional preferred units, will have the following effects:

- our existing common unitholders’ proportionate ownership interest in us will decrease;
- our amount of cash available for distribution to common unitholders may decrease;
- our ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding common unit may be diminished; and
- the market price of our common units may decline.

Table of Contents

ETO and the holders of the Preferred Units may sell our common units in the public or private markets, and such sales could have an adverse impact on the trading price of our common units.

As of December 31, 2018, ETO holds an aggregate of 46,056,228 common units in us (after giving effect to the conversion of 6,397,965 Class B Units to common units). We have granted certain registration rights to ETO and its affiliates with respect to any common units they own, and have filed a registration statement with the SEC for the benefit of the holders of the Preferred Units with respect to any common units they may own upon conversion of the Preferred Units or exercise of the Warrants. The sale of these common units in the public or private markets could have an adverse impact on the price of our common units or on any trading market that may develop.

The 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 the General Partner and its affiliates own more than 80% of our outstanding common units, the General Partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of our 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 the 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 common units. ETO currently owns an aggregate of approximately 44% of our outstanding common units (before giving effect to the conversion of the Class B Units into 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 the general partner. The Partnership is organized under Delaware law and conducts business in a number of other states, and in some of those states, the limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established. You could be liable for any and all of our obligations as if you were a general partner if a court or governmental 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 the General Partner, to approve some amendments to the Partnership Agreement or to take other actions under the Partnership Agreement constitute “control” of our business.

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

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17-607 of the Delaware Revised Uniform Limited Partnership Act (the “Delaware Act”), we may not make a distribution if the distribution would cause our liabilities to exceed the fair value of our assets. The Delaware Act 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. Liabilities to partners on account of their interest in the Partnership and liabilities that are nonrecourse to the Partnership are not counted for purposes of determining whether a distribution is permissible.

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 the Board 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”).

Table of Contents

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 our common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested a ruling from the IRS on this or any other tax matter affecting us.

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

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

The 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 level of distributions on our common units may be adjusted to reflect the impact of that law or interpretation 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 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 interpretations at any time. From time to time, members of the U.S. Congress have proposed and considered substantive changes to the existing federal income tax laws that would affect publicly traded partnerships, including a prior legislative proposal that would have eliminated the qualifying income exception to the treatment of all publicly traded partnerships as corporations upon which we rely for our treatment as a partnership for U.S. federal income tax purposes. In addition, the Treasury Department has issued, and in the future may issue, regulations interpreting those laws that affect publicly traded partnerships. Although there are no such current legislative or administrative proposals, there can be no assurance that there will not be further changes to U.S. federal income tax laws or the Treasury Department's interpretation of the qualifying income rules in a manner that could impact our ability to qualify as a publicly traded partnership in the future.

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

Table of Contents

income tax purposes. We are unable to predict whether any changes or other proposals will ultimately be enacted. Any future legislative changes could negatively impact the value of an investment in our common units. You are urged to consult with your own tax advisor with respect to the status of regulatory or administrative developments and proposals and their potential effect on your investment in our common units.

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

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

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

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

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

It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS, and the outcome of any IRS contest, may have a materially adverse impact on the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and the General Partner because the costs will reduce our cash available for distribution.

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

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

Table of Contents

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

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

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

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

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

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

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

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

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

Non-U.S. unitholders are generally taxed and subject to income tax filing requirements by the United States on income effectively connected with a U.S. trade or business (“effectively connected income”). Income allocated to our unitholders and any gain from the sale of our units will generally be considered to be “effectively connected” with a U.S.

Table of Contents

trade or business. As a result, distributions to a non-U.S. unitholder will be subject to withholding at the highest applicable effective tax rate and a non-U.S. unitholder who sells or otherwise disposes of a unit will also be subject to U.S. federal income tax on the gain realized from the sale or disposition of that unit.

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

We treat each purchaser of our 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 our common units.

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

We generally 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 generally 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 (i) certain deductions for depreciation of capital additions, (ii) gain or loss realized on a sale or other disposition of our assets, and (iii) in the discretion of the general partner, any other extraordinary item of income, gain, loss or deduction based upon ownership on the Allocation Date. Treasury Regulations allow a similar monthly simplifying convention, but such regulations do not specifically authorize all aspects of our proration method. If the IRS were to challenge our proration method, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

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

Because there are no specific rules governing the federal income tax consequences of loaning a partnership interest, a unitholder whose common units are the subject of a securities loan may be considered to have disposed of the loaned common units. In that case, the unitholder 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 determine whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.

Table of Contents

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

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

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

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

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

We currently conduct business and control assets 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 and pay any taxes due in these jurisdictions. Unitholders should consult with their own tax advisors regarding the filing of such tax returns, the payment of such taxes, and the deductibility of any taxes paid.

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, 2018, our headquarters consisted of 12,342 square feet of leased space located at 100 Congress Avenue, Austin, Texas 78701.

ITEM 3.Legal Proceedings

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.

ITEM 4.Mine Safety Disclosures

None.

Table of Contents

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 14, 2019, we had 90,000,504 common units outstanding. ETO owns 100% of the membership interests in the General Partner. As of February 14, 2019, ETO owned approximately 44% of our outstanding common units (before giving effect to the conversion of the Class B Units into common units).

As of February 14, 2019, we had outstanding 6,397,965 Class B Units which represent limited partner interests in the Partnership, all of which were held by ETO. Each Class B Unit will automatically be converted into one common unit following the record date attributable to the quarter ending June 30, 2019. Each Class B Unit has all of the rights and obligations of a common unit except the right to participate in distributions made prior to conversion into common units.

As of February 14, 2019, we had outstanding 500,000 Preferred Units representing limited partner interests in the Partnership, all of which were held by certain investment funds managed or advised by EIG Global Energy Partners and FS Energy and Power Fund (collectively, the "Preferred Unitholders"). The Preferred Units rank senior to the common units with respect to distributions and rights upon liquidation. The Preferred Unitholders are entitled to receive cumulative quarterly distributions equal to $24.375 per Preferred Unit, which may be paid in cash or, subject to certain limits, a combination of cash and additional Preferred Units as determined by the General Partner with respect to any quarter ending on or prior to June 30, 2019.

The Preferred Units are convertible, at the option of the Preferred Unitholders, into common units as follows: one third on or after April 2, 2021, two thirds on or after April 2, 2022, and the remainder on or after April 2, 2023. On or after April 2, 2023, we have the option to redeem all or any portion of the Preferred Units then outstanding. On or after April 2, 2028, the Preferred Unitholders have the right to require us to redeem all or a portion of the Preferred Units then outstanding, the purchase price for which we may elect to pay up to 50% in common units, subject to certain additional limits.

Our common units, which represent limited partner interests in us, are listed on the New York Stock Exchange ("NYSE") under the symbol "USAC."

Holders

At the close of business on February 14, 2019, based on information received from the transfer agent of the common units, we had 58 holders of record of our common units. The number of record holders does not include holders of common units held in “street name” or persons, partnerships, associations, corporations or other entities identified in security position listings maintained by depositories. There is no established public trading market for the Preferred Units, all of which are owned by the Preferred Unitholders. Please read Part II, Item 8 (“Financial Statements and Supplementary Data—Note 11—Preferred Units and Warrants and –Note 12—Partners’ Capital”).

Selected Information from the Partnership Agreement

Set forth below is a summary of the significant provisions of the Partnership Agreement that relate to available cash.

Available Cash

The 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, first to the holders of the Preferred Units and then to the common unitholders. The 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 the General Partner to provide for the proper conduct of our business, comply with applicable law, the Credit Agreement 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.

Issuer Purchases of Equity Securities

None.

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

None.

Equity Compensation Plan

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

ITEM 6.Selected Financial Data

SELECTED HISTORICAL FINANCIAL DATA

In the table below we have presented certain selected financial data for USA Compression Partners, LP and the USA Compression Predecessor for each of the years in the five-year period ended December 31, 2018, which has been derived from our audited consolidated financial statements for the years ended December 31, 2018, 2017, 2016 and 2015. The financial data for the year ended December 31, 2014 is unaudited. For periods prior to the Transactions Date, the table presents selected financial data for the USA Compression Predecessor and periods after the Transactions Date refer to the Partnership. 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 – Basis of Presentation and Significant Accounting Policies and Note 17 – 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 measures 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.

Table of Contents

	Year Ended December 31,				
	2018	2017	2016	2015	2014
	(in thousands, except per unit amounts)				
Revenues:					
Contract operations	$ 546,896	$ 249,346	$ 239,143	$ 281,589	$ 243,371
Parts and service	20,402	10,085	7,921	27,686	56,108
Related party	17,054	17,240	16,873	15,200	20,688
Total revenues	584,352	276,671	263,937	324,475	320,167
Costs of operations:					
Costs of operations, exclusive of depreciation and amortization	214,724	125,204	112,898	139,301	154,448
Gross operating margin (1)	369,628	151,467	151,039	185,174	165,719
Other operating and administrative costs and expenses:					
Selling, general and administrative	68,995	24,944	22,739	33,961	23,339
Depreciation and amortization	213,692	166,558	155,134	148,930	134,477
Loss (gain) on disposition of assets	12,964	(367)	120	(603)	986
Impairment of compression equipment	8,666	—	—	—	—
Impairment of goodwill	—	223,000	—	—	—
Total other operating and administrative costs and expenses	304,317	414,135	177,993	182,288	158,802
Operating income (loss)	65,311	(262,668)	(26,954)	2,886	6,917
Other income (expense):					
Interest expense, net	(78,377)	—	—	—	—
Other	41	(223)	(153)	(140)	(114)
Total other expense	(78,336)	(223)	(153)	(140)	(114)
Net income (loss) before income tax expense (benefit)	(13,025)	(262,891)	(27,107)	2,746	6,803
Income tax expense (benefit)	(2,474)	1,843	(163)	(1,445)	1,678
Net income (loss)	$ (10,551)	$ (264,734)	$ (26,944)	$ 4,191	$ 5,125
Adjusted EBITDA (1)	$ 320,475	$ 130,348	$ 131,686	$ 155,045	$ 145,168
DCF (1)	$ 177,757	$ 109,326	$ 123,442	$ 147,192	$ 136,774
Basic and diluted net loss per common unit (2)	$ (0.43)				
Basic and diluted net loss per Class B Unit (2)	$ (2.33)				
Cash distributions declared per common unit (2)	$ 1.575				
Other Financial Data:					
Capital expenditures	$ 241,179	$ 175,508	$ 59,234	$ 249,788	$ 318,099
Cash flows provided by (used in):					
Operating activities	$ 226,340	$ 135,956	$ 130,063	$ 164,324	$ 141,292
Investing activities	$ (779,663)	$ (142,458)	$ (36,767)	$ (249,805)	$ (346,869)
Financing activities	$ 549,409	$ (3,666)	$ (90,367)	$ 96,733	$ 205,577

Balance Sheet Data (at period end):					
Working capital (3)	$ 68,141	$ 27,091	$ 62,424	$ 55,519	$ 9,550
Total assets	$ 3,774,649	$ 1,718,953	$ 1,960,416	$ 2,102,933	$ 2,037,977
Long-term debt	$ 1,759,058	$ —	$ —	$ —	$ —
Partners' capital and predecessor parent company net investment	$ 1,378,856	$ 1,664,870	$ 1,929,223	$ 2,042,996	$ 1,930,817

(1) Please refer to "—Non-GAAP Financial Measures" below.
(2) Earnings per unit is not applicable to the USA Compression Predecessor as the USA Compression Predecessor had no outstanding common units prior to the Transactions.
(3) Working capital is defined as current assets minus current liabilities.

42

Table of Contents

Non-GAAP Financial Measures

Gross Operating Margin

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

Adjusted EBITDA

We define EBITDA as net income (loss) before net interest expense, depreciation and amortization expense, and income tax expense (benefit). We define Adjusted EBITDA as EBITDA plus impairment of compression equipment, impairment of goodwill, interest income on capital lease, unit-based compensation expense, severance charges, certain transaction fees, loss (gain) on disposition of assets and other. We view Adjusted EBITDA as one of management’s primary tools for evaluating our results of operations, 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 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 may provide a more complete understanding of our performance than GAAP results alone. We also believe that external users of our financial statements benefit from having access to the same financial measures that management uses in evaluating the results of our business.

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

Because we use capital assets, depreciation, impairment of compression equipment and the interest cost of acquiring compression equipment are also necessary elements of our costs. Unit-based compensation expense related to 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 Adjusted EBITDA, to evaluate

Table of Contents

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 most closely comparable GAAP measures, understanding the differences between the measures and incorporating this knowledge into their 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,				
	2018	2017	2016	2015	2014
Net income (loss)	$ (10,551)	$ (264,734)	$ (26,944)	$ 4,191	$ 5,125
Interest expense, net	78,377	—	—	—	—
Depreciation and amortization	213,692	166,558	155,134	148,930	134,477
Income tax expense (benefit)	(2,474)	1,843	(163)	(1,445)	1,678
EBITDA	$ 279,044	$ (96,333)	$ 128,027	$ 151,676	$ 141,280
Impairment of compression equipment (1)	8,666	—	—	—	—
Impairment of goodwill (2)	—	223,000	—	—	—
Interest income on capital lease	709	—	—	—	—
Unit-based compensation expense (3)	11,740	4,048	3,539	3,972	2,902
Transaction expenses for acquisitions (4)	4,181	—	—	—	—
Severance charges	3,171	—	—	—	—
Loss (gain) on disposition of assets	12,964	(367)	120	(603)	986
Adjusted EBITDA	$ 320,475	$ 130,348	$ 131,686	$ 155,045	$ 145,168
Interest expense, net	(78,377)	—	—	—	—
Income tax expense (benefit)	2,474	(1,843)	163	1,445	(1,678)
Interest income on capital lease	(709)	—	—	—	—
Non-cash interest expense	5,080	—	—	—	—
Transaction expenses for acquisitions	(4,181)	—	—	—	—
Severance charges	(3,171)	—	—	—	—
Other	(2,030)	24	(748)	3,380	2,433
Changes in operating assets and liabilities	(13,221)	7,427	(1,038)	4,454	(4,631)
Net cash provided by operating activities	$ 226,340	$ 135,956	$ 130,063	$ 164,324	$ 141,292

(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 the USA Compression Predecessor recognized for the year ended December 31, 2017, 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 year ended December 31, 2018, unit-based compensation expense included $1.3 million of cash payments related to quarterly payments of distribution equivalent rights on outstanding phantom unit awards and $3.7 million related to the cash portion of any settlement of phantom unit awards upon vesting. The remainder of the unit-based compensation expense is related to non-cash adjustments to the unit-based compensation liability.

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

Distributable Cash Flow

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

Table of Contents

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

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

Because we use capital assets, depreciation and impairment of compression equipment, (gain) loss on disposition of assets, and maintenance capital expenditures are necessary elements of our costs. Unit-based compensation expense related to 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 their decision making processes.

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,				
	2018	2017	2016	2015	2014
Net income (loss)	$ (10,551)	$ (264,734)	$ (26,944)	$ 4,191	$ 5,125
Non-cash interest expense	5,080	—	—	—	—
Non-cash income tax expense (benefit)	(2,663)	1,801	(155)	(1,461)	1,683
Depreciation and amortization	213,692	166,558	155,134	148,930	134,477
Unit-based compensation expense (1)	11,740	4,048	3,539	3,972	2,902
Impairment of compression equipment (2)	8,666	—	—	—	—
Impairment of goodwill (3)	—	223,000	—	—	—
Transaction expenses for acquisitions (4)	4,181	—	—	—	—
Severance charges	3,171	—	—	—	—
Proceeds from insurance recovery	409	—	—	—	—
Loss (gain) on disposition of assets	12,964	(367)	120	(603)	986
Distributions on Preferred Units	(36,430)	—	—	—	—

Maintenance capital expenditures (5)	(32,502)	(20,980)	(8,252)	(7,837)	(8,399)
DCF	$ 177,757	$ 109,326	$ 123,442	$ 147,192	$ 136,774
Maintenance capital expenditures	32,502	20,980	8,252	7,837	8,399
Changes in operating assets and liabilities	(13,221)	7,427	(1,038)	4,454	(4,631)
Transaction expenses for acquisitions	(4,181)	—	—	—	—
Severance charges	(3,171)	—	—	—	—
Distributions on Preferred Units	36,430	—	—	—	—
Other	224	(1,777)	(593)	4,841	750
Net cash provided by operating activities	$ 226,340	$ 135,956	$ 130,063	$ 164,324	$ 141,292

(1) For the year ended December 31, 2018, unit-based compensation expense includes $1.3 million of cash payments related to quarterly payments of distribution equivalent rights on outstanding phantom unit awards and $3.7 million related to the cash portion of any settlement of phantom unit awards upon vesting. The remainder of the unit-based compensation expense is related to non-cash adjustments to the unit-based compensation liability.

Table of Contents

(2) 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.
(3) For further discussion of the goodwill impairment the USA Compression Predecessor recognized for the year ended December 31, 2017, 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”).
(4) Represents certain transaction expenses related to potential and completed acquisitions and other items. We believe it is useful to investors to exclude these fees.
(5) Reflects actual 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, 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 divided by distributions declared to common unitholders in respect of such period. Cash Coverage Ratio is defined as DCF divided by cash distributions expected to be paid to common unitholders in respect of such period, after taking into account the non-cash impact of the DRIP. We believe DCF Coverage Ratio and Cash Coverage Ratio are important measures of operating performance because they allow management, investors and others to gauge our ability to pay cash distributions to common 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.

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

	Year Ended December 31,				
	2018 (4)	2017 (5)	2016 (5)	2015 (5)	2014 (5)
DCF	$ 177,757	$ 109,326	$ 123,442	$ 147,192	$ 136,774
Distributions for DCF coverage ratio (1)	$ 141,699				
Distributions reinvested in the DRIP (2)	688				
Distributions for Cash Coverage Ratio (3)	$ 141,011				
DCF Coverage Ratio	1.25				
Cash Coverage Ratio	1.26				

(1) Represents distributions to the holders of our common units as of the record date.
(2) Represents estimated distributions to holders enrolled in the DRIP as of the record date.
(3) Represents cash distributions declared on our common units not participating in the DRIP.

(4) Distributions for the year ended December 31, 2018 reflect only three quarters of distributions as the USA Compression Predecessor did not pay distributions prior to the Transactions Date. DCF, however, reflects a full year of DCF. On a pro forma basis, both the DCF Coverage Ratio and Cash Coverage Ratio for the year ended December 31, 2018 was 1.10x when using comparable three quarters of DCF and three quarters of distributions.

(5) DCF Coverage Ratio and Cash Coverage Ratio are not applicable to the USA Compression Predecessor as the USA Compression Predecessor had no outstanding common units for each period.

Table of Contents

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

Following the transactions described in further detail below, CDM Resource Management LLC and CDM Environmental & Technical Services LLC, which together represent the CDM Compression Business (the “USA Compression Predecessor”), has been determined to be the historical predecessor of USA Compression Partners, LP (the “Partnership”) for financial reporting purposes. The USA Compression Predecessor is considered the predecessor of the Partnership because Energy Transfer Equity, L.P. (“ETE”), through its wholly owned subsidiary Energy Transfer Partners, L.L.C., controlled the USA Compression Predecessor prior to the transactions described below and obtained control of the Partnership through its acquisition of USA Compression GP, LLC, the general partner of the Partnership (the “General Partner”).

The closing of the Transactions occurred on April 2, 2018 (the “Transactions Date”) and has been reflected in the consolidated financial statements of the Partnership.

In October 2018, ETE and Energy Transfer Partners, L.P. (“ETP”) completed the merger of ETP with a wholly owned subsidiary of ETE in a unit-for-unit exchange (the “ETE Merger”). Following the closing of the ETE Merger, ETE changed its name to “Energy Transfer LP” and ETP changed its name to “Energy Transfer Operating, L.P.” (“ETO”). Upon the closing of the ETE Merger, ETE contributed to ETP 100% of the limited liability company interests in the General Partner. References herein to “ETP” refer to Energy Transfer Partners, L.P. for periods prior to the ETE Merger and ETO following the ETE Merger, and references to “ETE” refer to Energy Transfer Equity, L.P. for periods prior to the ETE Merger and Energy Transfer LP following the ETE Merger.

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”). All references in this section to the USA Compression Predecessor, as well as the terms “our,” “we,” “us” and “its” refer to the USA Compression Predecessor when used in a historical context or in reference to the periods prior to the Transactions Date, unless the context otherwise requires or where otherwise indicated. All references in this section to the Partnership, as well as the terms “our,” “we,” “us” and “its” refer to USA Compression Partners, LP, together with its consolidated subsidiaries, including the USA Compression Predecessor, when used in the present or future tense and for periods subsequent to the Transactions Date, unless the context otherwise requires or where otherwise indicated.

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. Demand for our services is driven by the domestic production of natural gas and crude oil; as such, we have focused our activities in areas of attractive natural gas and crude oil production growth, which are generally found in these shale and unconventional resource plays. According to studies promulgated by the Energy Information Agency ("EIA"), the production and transportation volumes in these shale plays are expected to increase over the long term due to the comparatively attractive economic returns versus returns achieved in many conventional basins. Furthermore, the changes in production volumes and pressures of shale plays over time require a wider range of compression services than in conventional basins. We believe we are well-positioned to meet these changing operating conditions due to the flexibility of our compression units. While our business focuses largely on compression services serving infrastructure applications, including centralized natural gas gathering systems and processing facilities, which utilize large horsepower compression units, typically in shale plays, we also provide compression services in more mature conventional basins, including gas lift applications on crude oil wells targeted by horizontal drilling techniques. Gas lift, a process by which natural gas is injected into the production tubing of an existing producing well, in order to reduce the hydrostatic pressure and allow 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.

Table of Contents

CDM Acquisition and Issuance of Class B Units

On the Transactions Date, we consummated the transactions contemplated by the Contribution Agreement dated January 15, 2018, pursuant to which, among other things, we acquired all of the issued and outstanding membership interests of the USA Compression Predecessor from ETP (the "CDM Acquisition") in exchange for aggregate consideration of approximately $1.7 billion, consisting of (i) 19,191,351 common units representing limited partner interests in us (ii) 6,397,965 Class B units representing limited partner interests in us ("Class B Units") and (iii) $1.2 billion in cash (including customary closing adjustments).

General Partner Purchase Agreement

On the Transactions Date and in connection with the closing of the CDM Acquisition, we consummated the transactions contemplated by the Purchase Agreement dated January 15, 2018, by and among ETE, ETP LLC, USA Compression Holdings, LLC ("USA Compression Holdings") and, solely for certain purposes therein, R/C IV USACP Holdings, L.P. and ETP, pursuant to which, among other things, ETE acquired from USA Compression Holdings (i) all of the outstanding limited liability company interests in the General Partner and (ii) 12,466,912 common units for cash consideration paid by ETE to USA Compression Holdings equal to $250.0 million (the "GP Purchase"). Upon the closing of the ETE Merger, ETE contributed all of the interests in the General Partner and the 12,466,912 common units to ETP.

Equity Restructuring Agreement

On the Transactions Date and in connection with the closing of the CDM Acquisition, we consummated the transactions contemplated by the Equity Restructuring Agreement dated January 15, 2018, pursuant to which, among other things, the Partnership, the General Partner and ETE agreed to cancel the Partnership's Incentive Distribution Rights ("IDRs") and convert the General Partner Interest (as defined in the Equity Restructuring Agreement) into a non-economic general partner interest, in exchange for the Partnership's issuance of 8,000,000 common units to the General Partner (the "Equity Restructuring").

The CDM Acquisition, GP Purchase and Equity Restructuring are collectively referred to as the "Transactions."

Series A Preferred Unit and Warrant Private Placement

On the Transactions Date, we completed a private placement of $500 million in the aggregate of (i) newly authorized and established Preferred Units and (ii) warrants to purchase common units (the "Warrants") pursuant to a Series A Preferred Unit and Warrant Purchase Agreement dated January 15, 2018, between the Partnership and certain investment funds managed or advised by EIG Global Energy Partners and FS Energy and Power Fund (collectively, the "Preferred Unitholders"). We issued 500,000 Preferred Units with a face value of $1,000 per Preferred Unit and issued two tranches of Warrants to the Preferred Unitholders, which included Warrants to purchase 5,000,000 common units with a strike price of $17.03 per unit and 10,000,000 common units with a strike price of $19.59 per unit. The Warrants may be exercised by the holders thereof at any time beginning April 2, 2019 and before April 2, 2028.

Table of Contents

Senior Notes Issuance

On March 23, 2018, the Partnership and its wholly-owned subsidiary, USA Compression Finance Corp. (“Finance Corp”), co-issued $725.0 million in aggregate principal amount of the Senior Notes that mature on April 1, 2026. The Senior Notes accrue interest at the rate of 6.875% per year. Interest on the Senior Notes is payable semi-annually in arrears on April 1 and October 1, with the first such payment having occurred on October 1, 2018.

On January 14, 2019, the Partnership completed an exchange offer whereby holders of the Senior Notes exchanged all of the Senior Notes for an equivalent amount of senior notes registered under the Securities Act of 1933 (the “Exchange Notes”). The Exchange Notes are substantially identical to the Senior Notes, except that the Exchange Notes have been registered with the SEC and do not contain the transfer restrictions, restrictive legends, registration rights or additional interest provisions of the Senior Notes.

Credit Agreement Amendment and Restatement

On the Transactions Date, we entered into the Sixth Amended and Restated Credit Agreement (the “Credit Agreement”) by and among the Partnership, as borrower, USAC OpCo 2, LLC, USAC Leasing 2, LLC, USA Compression Partners, LLC, USAC Leasing, LLC, CDM Resource, CDM E&T and Finance Corp, the lenders party thereto from time to time, JPMorgan Chase Bank, N.A., as agent and a letter of credit (“LC”) issuer, JPMorgan Chase Bank, N.A., Barclays Bank PLC, Regions Capital Markets, a division of Regions Bank, RBC Capital Markets and Wells Fargo Bank, N.A., as joint lead arrangers and joint book runners, Barclays Bank PLC, Regions Bank, RBC Capital Markets and Wells Fargo Bank, N.A., as syndication agents, and MUFG Union Bank, N.A., SunTrust Bank and The Bank of Nova Scotia, as senior managing agents. The Credit Agreement amended and restated that certain Fifth Amended and Restated Credit Agreement, dated as of December 13, 2013, as amended (the “Fifth A&R Credit Agreement”).

The Credit Agreement amended the Fifth A&R Credit Agreement to, among other things, (i) increase the borrowing capacity under the Credit Agreement from $1.1 billion to $1.6 billion (subject to availability under a borrowing base), (ii) extend the termination date (and the maturity date of the obligations thereunder) from January 6, 2020 to April 2, 2023, (iii) subject to the terms of the Credit Agreement, permit up to $400.0 million of future increases in borrowing capacity, (iv) modify the leverage ratio covenant to be 5.75 to 1.0 through the end of the fiscal quarter ending March 31, 2019, 5.5 to 1.0 through the end of the fiscal quarter ending December 31, 2019, and 5.0 to 1.0 thereafter and (v) increase the applicable margin for eurodollar borrowings to range from 2.00% to 2.75%, depending on our leverage ratio, all as more fully set forth in the Credit Agreement.

General Trends and Outlook

Natural gas compression is a critical part of the natural gas value chain, facilitating the movement of natural gas throughout the domestic pipeline system. Our business is driven in part by the increasing volumes of natural gas being produced in this country and the areas and conditions in which it is produced. Without compression, natural gas will generally not move through a pipeline.

A significant amount of our assets are utilized in natural gas infrastructure applications, primarily in centralized natural gas gathering systems and processing facilities. Rather than being more closely tied to the wellhead impact of commodity price variability, these applications generally tend to be characterized by a long-term investment horizon on the part of our customers; as such, we have generally experienced stability in rates and higher sustained utilization rates relative to other businesses more tied to drilling activity and wellhead economics. In addition to assets utilized in infrastructure applications, a small portion of our fleet is used for gas lift applications in connection with crude oil production using horizontal drilling techniques.

Increasing levels of domestic natural gas production as a general rule require more installed compression in order to move the gas through the pipeline system and to the ultimate end user, whether that user be commercial, industrial or residential in nature. The U.S. Energy Information Administration January 2019 Short-Term Energy Outlook ("EIA Outlook") expects dry natural gas production to increase to 90.2 billion cubic feet per day ("Bcf/d") in 2019 (an increase

Table of Contents

of 8% over the record high production of 83.3 Bcf/d in 2018) and to 92.2 Bcf/d in 2020. The expected growth in natural gas production is largely in response to improved drilling efficiency and cost reductions, higher associated gas production from oil-directed rigs, and increased takeaway pipeline capacity from the highly productive Appalachia and Permian production regions, which are regions in which we provide compression services. Forecasted natural gas production growth is supported by planned expansions in liquefied natural gas (“LNG”) capacity and increased pipeline exports to Mexico. The EIA Outlook projects LNG gross exports will increase from 3.0 Bcf/d in 2018 to 5.1 Bcf/d in 2019 and to 6.8 Bcf/d in 2020, as three new liquefaction projects come online. Also from the EIA Outlook, natural gas pipeline exports to Mexico have increased as more infrastructure has been built to transport natural gas both to and within Mexico. U.S. pipeline exports to Mexico through October averaged 4.6 Bcf/d, increasing by 10% in 2018 compared with the same period in 2017. Exports to Mexico should continue to increase as more natural gas-fired power plants come online in Mexico and more pipeline infrastructure within Mexico is built.

We believe this increasing demand for natural gas will also create increasing demand for compression services, for both existing natural gas fields as they age and for the development of new natural gas fields. As such, we expect demand for our compression services to continue to increase throughout 2019 although we cannot predict any possible changes in such demand with reasonable certainty.

Particularly in the Permian and Delaware Basins, natural gas tends to be produced alongside crude oil, and is thus known as “associated” gas. Due to many factors, the Permian and Delaware Basins have experienced significant activity levels in recent years, and along with the production of crude oil, the EIA has reported an 81% increase in associated natural gas produced in those areas since December 2015. Because customers must handle the gas that is produced simultaneously with the oil, compression has been a critical part of the equation for our customers to be able to produce the desired crude oil and move it to market. As crude oil production grows in these areas, there will be demand for additional compression to handle the natural gas.

The EIA Outlook forecasts total U.S. crude oil production to average 12.1 million barrels per day (“b/d”) in 2019, up 10% from 2018 average production of 10.9 million b/d, which was the highest annual average on record, surpassing the previous record of 9.6 million b/d set in 1970. Average production in 2020 is expected to increase to 12.9 million b/d. Increased crude oil production from tight rock formations within the Permian region in Texas and New Mexico accounts for 0.6 million b/d of the U.S. total growth expected in 2019 and 0.5 million b/d in 2020. The EIA Outlook expects the Permian region to produce 4.8 million b/d of crude oil by the end of 2020, which is about 1.0 million b/d more than estimated December 2018 levels and would represent about 36% of total U.S. crude oil production at the end of 2020. Favorable geology and technological and operational improvements have allowed the Permian to become one of the most economic regions for oil production. The forecasted annual growth rate in 2019 of 0.6 million b/d is 0.4 million b/d slower than in 2018. The flattening of the growth rate reflects increasing pipeline capacity constraints in the Permian region, which is expected to temporarily lower wellhead prices for the region’s oil producers and to have a dampening effect on the Permian’s full production potential in the short term. Pipeline capacity constraints in the Permian are expected to be alleviated in the second half of 2019, with growth expected to accelerate on a monthly basis into 2020. WTI crude oil spot prices are forecast within the EIA Outlook to average $54 per barrel in 2019 and $60 per barrel in 2020, compared with $65 per barrel in 2018. Daily and monthly average crude oil prices could vary significantly from annual average forecasts due to global economic developments and geopolitical events in the coming months that could have the potential to push oil prices higher or lower than forecast. Uncertainty remains regarding the duration of, and members’ adherence to, the current Organization of the Petroleum Exporting

Countries (“OPEC”) production cuts, which could influence prices in either direction.

We believe the increase and relative stabilization of crude oil prices allowed for the continued build-out of related large-scale natural gas infrastructure projects, particularly in areas with favorable economics. These projects increased demand for our compression services throughout 2018 as we saw horsepower utilization increase from 87.5% at December 31, 2017 for the USA Compression Predecessor, to 94.0% at December 31, 2018 for our combined business.

We intend to prudently deploy capital for new compressor units in 2019. We have already entered into commitments to purchase all of our large horsepower compressor units in 2019, as the lead time to build these units is approximately one year or shorter. Most of our 2019 purchases of large horsepower compressor units are already committed to customers or under contract with customers due to the high demand and limited supply of these units.

Table of Contents

Factors Affecting the Comparability of our Operating Results

As described above, the USA Compression Predecessor has been deemed to be the accounting acquirer of the Partnership in accordance with applicable business combination accounting guidance, and, as a result, the historical financial statements reflect the balance sheet and results of operations of the USA Compression Predecessor for periods prior to the Transactions Date. Therefore, the Partnership’s future results of operations may not be comparable to the USA Compression Predecessor’s historical results of operations for the reasons described below.

The revenues generated by the Partnership will consist of the revenues from compression services as well as related ancillary revenues, including those generated by the USA Compression Predecessor, subsequent to the Transactions Date. The historical revenues included within the Partnership’s financial statements relating to periods prior to the Transactions Date will only be comprised of those of the USA Compression Predecessor.

Additionally, selling, general and administrative expenses will not be comparable to the selling, general and administrative expenses previously allocated to the USA Compression Predecessor by ETP. The Partnership’s selling, general and administrative expenses will also not be comparable to the historical USA Compression Predecessor’s selling, general and administrative expenses because the Partnership’s selling, general and administrative expenses will include the expenses associated with being a publicly traded master limited partnership whereas the USA Compression Predecessor was operated as a component of a larger company.

In connection with the Transactions, the Partnership and Finance Corp co-issued the Senior Notes and the Partnership entered into the Credit Agreement. The USA Compression Predecessor held no long-term debt and had no outstanding publicly traded equity securities. As a result, the Partnership’s long-term debt and related charges will not be comparable to the USA Compression Predecessor’s historical long-term debt and related charges. We expect ongoing sources of liquidity to include cash generated from operating activities, borrowings under the Credit Agreement, and additional issuances of debt and equity securities.

During the year ended December 31, 2018, we recorded $4.2 million in transaction expenses, $3.2 million in severance expenses and $6.8 million in unit-based compensation expense, all of which related to the CDM Acquisition.

Operating Highlights

The following table summarizes certain horsepower and horsepower utilization percentages for the periods presented and excludes certain gas treating assets for which horsepower is not a relevant metric.

	Year Ended December 31,			Percent Change	
Operating Data:	2018	2017 (9)	2016 (9)	2018	2017
Fleet horsepower (at period end) (1)	3,597,097	1,730,820	1,600,842	107.8 %	8.1 %
Total available horsepower (at period end) (2)	3,675,447	1,780,893	1,606,424	106.4 %	10.9 %
Revenue generating horsepower (at period end) (3)	3,262,470	1,395,328	1,227,899	133.8 %	13.6 %
Average revenue generating horsepower (4)	2,760,029	1,293,864	1,203,487	113.3 %	7.5 %
Average revenue per revenue generating horsepower per month (5)	$ 16.09	$ 15.84	$ 16.58	1.6 %	(4.5) %
Revenue generating compression units (at period end)	4,753	2,076	1,789	128.9 %	16.0 %
Average horsepower per revenue generating compression unit (6)	674	681	668	(1.0) %	1.9 %
Horsepower utilization (7):					
At period end	94.0 %	87.5 %	77.7 %	7.4 %	12.6 %
Average for the period (8)	91.9 %	82.4 %	77.0 %	11.5 %	7.0 %

(1) Fleet horsepower is horsepower for compression units that have been delivered to us (and excludes units on order). As of December 31, 2018, we had 131,750 horsepower on order for delivery during 2019.

Table of Contents

(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 an executed compression services contract.
(3) Revenue generating horsepower is horsepower under contract for which we are billing a customer.
(4) Calculated as the average of the month-end revenue generating horsepower for each of the months in the period.
(5) Calculated as the average of the result of dividing the contractual monthly rate for all units at the end of each month in the period by the sum of the revenue generating horsepower at the end of each month in the period.
(6) Calculated as the average of the month-end revenue generating horsepower per revenue generating compression unit for each of the months in the period.
(7) Horsepower utilization is calculated as (i) the sum of (a) revenue generating horsepower, (b) horsepower in our fleet that is under contract, but is not yet generating revenue and (c) horsepower not yet in our fleet that is under contract, not yet generating revenue and that is subject to a purchase order, divided by (ii) total available horsepower less idle horsepower that is under repair. Horsepower utilization based on revenue generating horsepower and fleet horsepower was 90.7%, 80.6% and 76.7% at December 31, 2018, 2017 and 2016, respectively.
(8) Calculated as the average utilization for the months in the period based on utilization at the end of each month in the period. Average horsepower utilization based on revenue generating horsepower and fleet horsepower was 88.0%, 76.9% and 75.9% for the years ended December 31, 2018, 2017 and 2016, respectively.
(9) Certain historical metrics attributable to the USA Compression Predecessor have been conformed to the Partnership's calculation methodology.

The 107.8% increase in fleet horsepower as of December 31, 2018 over the fleet horsepower as of December 31, 2017 was attributable to the horsepower acquired from the Partnership's historical assets as well as compression units added to our fleet to meet incremental demand for our compression services by new and existing customers. The 133.8% increase in revenue generating horsepower as of December 31, 2018 over December 31, 2017 was primarily due to the addition of the Partnership's historical assets in addition to organic growth in our large horsepower fleet. The 1.6% increase in average revenue per revenue generating horsepower per month for the year ended December 31, 2018 over December 31, 2017 was primarily due to contracts on new compression units as well as selective price increases on the existing fleet.

The 8.1% increase in fleet horsepower as of December 31, 2017 compared to the fleet horsepower as of December 31, 2016 was attributable to new compression units added to the USA Compression Predecessor's fleet to meet the then-expected demand by new and existing customers for compression services. The 13.6% increase in revenue generating horsepower as of December 31, 2017 compared to December 31, 2016 was primarily due to increased customer demand in the Permian, Niobrara and Mid-continent Regions. The 1.9% increase in average horsepower per revenue generating compression unit as of December 31, 2017 compared to December 31, 2016 was primarily due to the redeployment of smaller horsepower units that were previously idle. The 4.5% decrease in average revenue per revenue generating horsepower per month for the year ended December 31, 2017 compared to December 31, 2016 was primarily due to an increase in the average horsepower per revenue generating compression unit in the current period, resulting from an increase in the number of large horsepower compression units which typically generate lower average revenue per revenue generating horsepower than do small horsepower compression units.

The 9.5% increase in average horsepower utilization during the year ended December 31, 2018 compared to the year ended December 31, 2017 was primarily attributable to the higher utilization of the Partnership's historical fleet that was added to the USA Compression Predecessor's fleet during the year ended December 31, 2018, and resulted in a decrease in total idle horsepower as a percentage of total available horsepower during the year ended December 31, 2018.

The 5.4% increase in average horsepower utilization during the year ended December 31, 2017 compared to the year ended December 31, 2016 was primarily attributable to increased customer demand due to increased operating activity in the oil and gas industry. The fluctuation in utilization components also describes the changes in period end horsepower utilization as of December 31, 2017 compared to December 31, 2016.

The 11.1% increase in average horsepower utilization based on revenue generating horsepower and fleet horsepower during the year ended December 31, 2018 compared to December 31, 2017 was primarily attributable to the higher

Table of Contents

utilization of the Partnership's fleet that was added to the USA Compression Predecessor's fleet during the year ended December 31, 2018, and resulted in an increase in total active horsepower as a percentage of total fleet horsepower during the year ended December 31, 2018.

The 1.0% increase in average horsepower utilization based on revenue generating horsepower and fleet horsepower during the year ended December 31, 2017 compared to December 31, 2016 was primarily attributable to increased customer demand in the Permian, Niobrara and Mid-continent Regions. The overall decrease in idle horsepower is the result of increased customer demand as a result of increased operating activity in the oil and gas industry. These factors also describe the variances in period end horsepower utilization based on revenue generating horsepower and fleet horsepower between the year ended December 31, 2017 and the year ended December 31, 2016.

Financial Results of Operations

Year ended December 31, 2018 compared to the year ended December 31, 2017

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

	Year Ended December 31, 2018	2017	Percent Change	
Revenues:				
Contract operations	$ 546,896	$ 249,346	119.3	%
Parts and service	20,402	10,085	102.3	%
Related party	17,054	17,240	(1.1)	%
Total revenues	584,352	276,671	111.2	%
Costs and expenses:				
Cost of operations, exclusive of depreciation and amortization	214,724	125,204	71.5	%
Gross operating margin	369,628	151,467	144.0	%
Other operating and administrative costs and expenses:				
Selling, general and administrative	68,995	24,944	176.6	%
Depreciation and amortization	213,692	166,558	28.3	%
Loss (gain) on disposition of assets	12,964	(367)	3,632.4	%
Impairment of compression equipment	8,666	—	*	%
Impairment of goodwill	—	223,000	(100.0)	%
Total other operating and administrative costs and expenses	304,317	414,135	(26.5)	%
Operating income (loss)	65,311	(262,668)	(124.9)	%
Other income (expense):				
Interest expense, net	(78,377)	—	*	%
Other	41	(223)	(118.4)	%

Total other expense	(78,336)	(223)	*	%
Net loss before income tax expense (benefit)	(13,025)	(262,891)	(95.0)	%
Income tax expense (benefit)	(2,474)	1,843	(234.2)	%
Net loss	$ (10,551)	$ (264,734)	(96.0)	%

* Not meaningful.

Contract operations revenue. During the year ended December 31, 2018, we increased our operational capability and expanded our geographic footprint as a result of the addition of the Partnership's historical assets and experienced a year-to-year increase in demand for our compression services driven by increased operating activity in the oil and gas industry, resulting in a $297.6 million increase in our contract operations revenue. The Partnership's historical assets accounted for $252.1 million of contract operations revenue for the year ended December 31, 2018. Average revenue generating horsepower increased 113.3% during the year ended December 31, 2018 over the year ended December 31, 2017 and average revenue per revenue generating horsepower per month increased 1.6% from $15.84 for the year ended December 31, 2017 to $16.09 for the year ended December 31, 2018.

Parts and service revenue. The $10.3 million increase in parts and service revenue was primarily attributable to an increase in maintenance work performed on units at our customers' locations that are outside the scope of our core maintenance activities and offered as a courtesy to our customers, and freight and crane charges that are directly reimbursable by customers. Demand for retail parts and services fluctuates from period to period based on the varying needs of our customers.

Related party revenue. Related party revenue was materially consistent between periods. The related parties of the USA Compression Predecessor remain related parties of the Partnership because the USA Compression Predecessor's ultimate parent company obtained control of the Partnership through its control of the General Partner.

Cost of operations, exclusive of depreciation and amortization. The $89.5 million increase in cost of operations was driven by (1) a $38.2 million increase in direct expenses, such as parts, fluids and freight expenses, (2) an $18.2 million increase in direct labor expenses, (3) a $9.5 million increase in retail parts and service expenses, which have a corresponding increase in parts and service revenue, (4) a $9.4 million increase in property and other taxes, (5) a $5.5 million increase in outside maintenance expenses and (6) a $5.2 million increase in vehicle expenses. The increase in direct parts, fluids, labor, property taxes and vehicle expenses is primarily driven by the increase in average revenue generating horsepower during the current period as a result of the addition of the Partnership's historical assets. The increase in outside maintenance expenses was due to greater use of third-party labor during 2018. We do not expect to incur significant amounts of outside maintenance expense in future periods.

Gross operating margin. The $218.2 million increase in gross operating margin was primarily due to an increase in revenues, partially offset by an increase in cost of operations, exclusive of depreciation and amortization, during the year ended December 31, 2018 due to the addition of the Partnership's historical assets.

Selling, general and administrative expense. The $44.1 million increase in selling, general and administrative expense for the year ended December 31, 2018 was primarily attributable to (1) a $19.7 million increase in payroll and benefits expenses, (2) a $7.7 million increase in unit-based compensation expense, (3) a $5.6 million increase in professional fees expenses, (4) $4.2 million of non-recurring advisory, legal and accounting fees, all related to the Transactions, (5) $3.0 million of severance charges, all related to the Transactions, and (6) a $2.4 million increase in bad debt expense, primarily due to a $1.8 million recovery of bad debt expense during the year ended December 31, 2017. Payroll and benefits expenses and professional fees increased due to the addition of the Partnership's historical assets to the USA Compression Predecessor's operations. Unit-based compensation expense increased primarily due to the accelerated vesting of certain outstanding phantom units as a result of the change in control associated with the Transactions along with the difference in the number of outstanding unvested phantom units of the USA Compression Predecessor as of December 31, 2017 compared to the Partnership as of December 31, 2018.

Depreciation and amortization expense. The $47.1 million increase in depreciation and amortization expense was primarily a result of $66.2 million in depreciation and amortization expense attributable to the addition of the Partnership's historical assets, which were adjusted to fair value in connection with the Transactions, offset by a $33.8

million decrease in depreciation expense to conform the useful lives used by the USA Compression Predecessor to those used by the Partnership. The remaining change in depreciation and amortization expense was primarily related to an increase in the USA Compression Predecessor’s gross property and equipment balances during the year ended December 31, 2018 compared to gross balances during the year ended December 31, 2017.

Loss (gain) on disposition of assets. The $13.0 million net loss on disposition of assets during the year ended December 31, 2018 was primarily attributable to disposals of various property and equipment by the USA Compression Predecessor prior to the Transactions Date.

Impairment of compression equipment. The $8.7 million impairment charge during the year ended December 31, 2018 was primarily a result of our evaluation of the future deployment of our idle fleet under then-current market conditions. Our evaluation determined that due to certain performance characteristics of the impaired equipment, such as excessive maintenance costs and the inability of the equipment to meet then-current emissions standards without excessive retrofitting costs, this equipment was unlikely to be accepted by customers under then-current market conditions. As a result of our evaluation during the year ended December 31, 2018, we determined to retire and re-utilize

Table of Contents

the key components of 103 compression units, with a total of approximately 33,000 horsepower that had been previously used to provide compression services in our business.

Impairment of goodwill. The USA Compression Predecessor recognized a $223.0 million impairment on goodwill during the year ended December 31, 2017 as a result of its annual goodwill impairment test, for which the USA Compression Predecessor's management determined its fair value using a weighted combination of the discounted cash flow method and the guideline company method. Additionally, the USA Compression Predecessor considered the presence and probability of subsequent events on market transactions in estimating the fair value of the company, such as the Transactions discussed in Note 1 to our consolidated financial statements. There was no impairment of goodwill during the year ended December 31, 2018.

Interest expense, net. The $78.4 million increase in interest expense, net was primarily attributable to interest expense incurred on the Senior Notes and outstanding borrowings under the Credit Agreement for which there were no comparable borrowings by the USA Compression Predecessor in the prior period. The interest rate on the Credit Agreement was 4.97% at December 31, 2018, and the weighted-average interest rate was 4.69% for the period from the Transactions Date to December 31, 2018. Average outstanding borrowings under the Credit Agreement was $984.7 million for the period from the Transactions Date to December 31, 2018.

Income tax expense (benefit). During the year ended December 31, 2018, we recorded an income tax benefit of $2.5 million, primarily related to a decrease in the deferred tax expense booked for the Texas Franchise Tax accrual, while during the year ended December 31, 2017, the USA Compression Predecessor recorded an income tax expense of $1.8 million, resulting from an increase in the deferred tax expense booked for the Texas Franchise Tax accrual.

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

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

	Year Ended December 31,		Percent	
	2017	2016	Change	
Revenues:				
Contract operations	$ 249,346	$ 239,143	4.3	%
Parts and service	10,085	7,921	27.3	%
Related party	17,240	16,873	2.2	%
Total revenues	276,671	263,937	4.8	%
Costs and expenses:				
Cost of operations, exclusive of depreciation and amortization	125,204	112,898	10.9	%

Gross operating margin	151,467	151,039	0.3	%
Other operating and administrative costs and expenses:				
Selling, general and administrative	24,944	22,739	9.7	%
Depreciation and amortization	166,558	155,134	7.4	%
Loss (gain) on disposition of assets	(367)	120	(405.8)	%
Impairment of compression equipment	—	—	*	%
Impairment of goodwill	223,000	—	*	%
Total other operating and administrative costs and expenses	414,135	177,993	132.7	%
Operating loss	(262,668)	(26,954)	874.5	%
Other income (expense):				
Interest expense	—	—	*	%
Other	(223)	(153)	45.8	%
Total other expense	(223)	(153)	45.8	%
Net loss before income tax expense (benefit)	(262,891)	(27,107)	869.8	%
Income tax expense (benefit)	1,843	(163)	1,230.7	%
Net loss	$ (264,734)	$ (26,944)	882.5	%

* Not meaningful.

Table of Contents

Contract operations revenue. During 2017, the USA Compression Predecessor experienced a year-to-year increase in demand for its compression services driven by increased operating activity in natural gas and crude oil production, resulting in a $10.2 million increase in contract compression and treating revenues. The increase was primarily attributable to increased customer demand in the Permian, Niobrara and Mid-Continent regions.

Parts and service revenue. The $2.2 million increase in installation services revenues was primarily attributable to the construction of additional amine plants.

Related party revenue. Related party revenues were earned through related party transactions in the ordinary course of business and at arms' length with various affiliated entities of ETP, including Regency Intrastate Gas, LP, Edwards Lime Gathering LLC and certain wholly owned subsidiaries of ETP. The $0.4 million increase in related party revenues was primarily attributable to additional compression service demand from such affiliates.

Cost of operations, exclusive of depreciation and amortization. The $12.3 million increase in cost of operations was primarily attributable to (1) horsepower growth of approximately 160,000, (2) a corresponding increase in parts and service revenue attributable to construction of additional amine plants and (3) an increase in revenue generating horsepower and treating equipment, labor rates, and the amount of overtime for employees.

Gross operating margin. The gross operating margin for the year ended December 31, 2017 was materially consistent with the year ended December 31, 2016.

Selling, general and administrative expense. The $2.2 million increase in general and administrative expense for the year ended December 31, 2017 was primarily attributable to an increase in salaries, health care, and unit-based compensation expenses driven by increased headcount and higher health insurance claims. ETP has allocated certain overhead costs associated with general and administrative services, including salaries and benefits, facilities, insurance, information services, human resources and other support departments to the USA Compression Predecessor. Where costs incurred on the USA Compression Predecessor's behalf could not be determined by specific identification, the costs were primarily allocated to the USA Compression Predecessor based on an average percentage of fixed assets, gross margin, capital, employee costs, and headcount. The USA Compression Predecessor's management believed these allocations were a reasonable reflection of the utilization of services provided. However, the allocations may not fully reflect the expenses that would have been incurred had the USA Compression Predecessor been a stand-alone company during the periods presented. During the years ended December 31, 2017 and 2016, ETP allocated general and administrative expenses of $3.6 million and $4.7 million, respectively, to the USA Compression Predecessor.

Depreciation and amortization expense. The $11.4 million increase in depreciation and amortization was primarily related to increased make ready cost with a useful life of two years as a result of increased utilization.

Loss (gain) on disposition of assets. During the year ended December 31, 2017, the $0.4 million gain was primarily attributable to the sale of select compression equipment with a sales price greater than book value. During the year ended December 31, 2016, the $0.1 million loss was primarily attributable to the sale of select compression equipment with a sales price less than book value.

Goodwill impairment. The $223.0 million impairment on goodwill during the year ended December 31, 2017 was a result of the USA Compression Predecessor's annual goodwill impairment test, for which the USA Compression Predecessor's management determined its fair value using a weighted combination of the discounted cash flow method and the guideline company method. Additionally, the USA Compression Predecessor considered the presence and probability of subsequent events on market transactions in estimating the fair value of the company, such as the Transactions discussed in Note 1 to our consolidated financial statements. There was no impairment of goodwill during the year ended December 31, 2016.

Income tax expense (benefit). The $2.0 million increase in income tax expense is primarily related to an increase in the deferred tax expense booked for the Texas Franchise Tax accrual.

Table of Contents

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)	2018	2017 (3)	2016 (3)	2018	2017
Gross operating margin	$ 369,628	$ 151,467	$ 151,039	144.0 %	0.3 %
Gross operating margin percentage (2)	63.3 %	54.7 %	57.2 %	15.7 %	(4.4) %
Adjusted EBITDA	$ 320,475	$ 130,348	$ 131,686	145.9 %	(1.0) %
Adjusted EBITDA percentage (2)	54.8 %	47.1 %	49.9 %	16.3 %	(5.6) %
DCF	$ 177,757	$ 109,326	$ 123,442	62.6 %	(11.4) %
DCF Coverage Ratio (4)	1.25 x				
Cash Coverage Ratio (4)	1.26 x				

(1) Gross operating margin, Adjusted EBITDA, DCF, DCF Coverage Ratio and Cash Coverage Ratio are all non-GAAP financial measures. Definitions of each measure, as well as reconciliations of each measure to its most directly comparable financial measure(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) Amounts attributed to the USA Compression Predecessor are calculated using the same definitions used by the Partnership. DCF Coverage Ratio and Cash Coverage Ratio are not applicable to the USA Compression Predecessor as the USA Compression Predecessor had no outstanding common units for each period.
(4) Distributions for the year ended December 31, 2018 reflect only three quarters of distributions as the USA Compression Predecessor did not pay distributions prior to the Transactions Date. DCF, however, reflects a full year of DCF. On a pro forma basis, both the DCF Coverage Ratio and Cash Coverage Ratio for the year ended December 31, 2018 was 1.10x when using comparable three quarters of DCF and three quarters of distributions.

Adjusted EBITDA. The $190.1 million, or 145.9%, increase in Adjusted EBITDA during the year ended December 31, 2018 was primarily attributable to the addition of the Partnership’s historical assets which was the primary cause of a $218.2 million increase in gross operating margin, offset by a $29.2 million increase in selling, general and administrative expenses, excluding transaction expenses, unit-based compensation expense and other non-recurring charges, during the year ended December 31, 2018.

The $1.3 million, or 1.0%, decrease in Adjusted EBITDA during the year ended December 31, 2017 was primarily attributable to a $1.7 million increase in selling, general and administrative expenses, excluding unit-based compensation expense, offset by a $0.4 million increase in gross operating margin during the year ended December 31, 2017.

Distributable Cash Flow. The $68.4 million, or 62.6%, increase in DCF during the year ended December 31, 2018 was primarily attributable to the addition of the Partnership's historical assets which was the primary cause of (1) a $218.2 million increase in gross operating margin offset by (2) a $73.3 million increase in cash interest expense, net, (3) $36.4 million of distributions on Preferred Units, (4) a $29.2 million increase in selling, general and administrative expenses, excluding transaction expenses, unit-based compensation expense and other non-recurring charges and (5) an $11.5 million increase in maintenance capital expenditures during the comparable period. The USA Compression Predecessor had no outstanding debt on which cash interest expense was paid in the prior period. The increase in selling, general and administrative expenses and maintenance capital expenditures was primarily due to additional activity as a result of the combination of the Partnership's legacy operations with those of the USA Compression Predecessor.

The $14.1 million, or 11.4%, decrease in DCF during the year ended December 31, 2017 was primarily due to a $12.7 million increase in maintenance capital expenditures and a $1.7 million increase in selling, general and administrative expenses, excluding unit-based compensation expense, offset by a $0.4 million increase in gross operating margin during the comparable period.

Coverage Ratios. Historical coverage ratios are not applicable as the USA Compression Predecessor had no outstanding common units for each period. Coverage ratios for the year ended December 31, 2018 reflect a full year of

Table of Contents

DCF but only three quarters of distributions as the USA Compression Predecessor did not pay any distributions prior to the Transactions Date.

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 the Credit Agreement and issuances of debt and equity securities, including under the DRIP.

We believe cash generated by operating activities and, where necessary, borrowings under the Credit Agreement will be sufficient to service our debt, fund working capital, fund our estimated expansion capital expenditures, fund our maintenance capital expenditures and pay distributions through 2019. 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 the Credit Agreement and issuances of debt and equity securities, including under the DRIP.

To fund a portion of the CDM Acquisition, on March 23, 2018 the Partnership and Finance Corp co-issued $725.0 million in aggregate principal amount of the Senior Notes and, on the Transactions Date, the Partnership issued the Preferred Units and Warrants for aggregate gross consideration of $500.0 million. The transaction fees associated with these issuances were financed with borrowings under the Credit Agreement. Also on the Transactions Date, the borrowing capacity under the Credit Agreement was increased from $1.1 billion to $1.6 billion.

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, 2018, 2017 and 2016 (in thousands):

	Year Ended December 31,		
	2018	2017	2016
Net cash provided by operating activities	$ 226,340	$ 135,956	$ 130,063
Net cash used in investing activities	(779,663)	(142,458)	(36,767)
Net cash provided by (used in) financing activities	549,409	(3,666)	(90,367)

Net cash provided by operating activities. The $90.4 million increase in net cash provided by operating activities for the year ended December 31, 2018 was due primarily to a $111.0 million increase in net income, as adjusted for non-cash items, and changes in other working capital.

The $5.9 million increase in net cash provided by operating activities for the year ended December 31, 2017 was due primarily to net horsepower growth and an increase in treating utilization in 2017.

Net cash used in investing activities. Net cash used in investing activities for the year ended December 31, 2018 related primarily to $1.2 billion of cash paid, offset by $710.5 million of cash received, each as part of the CDM Acquisition. Additionally, during the year ended December 31, 2018, net cash used in investing activities of $266.6 million related to purchases of new compression units, reconfiguration costs and related equipment and net cash provided by investing activities of $7.5 million and $0.4 million related to proceeds from disposition of property and equipment and proceeds from insurance recoveries, respectively.

Net cash used in investing activities for the years ended December 31, 2017 and 2016 related primarily to capital expenditures, including net horsepower growth, partially offset by proceeds from asset sales. For the years ended

December 31, 2017 and 2016, total capital expenditures were $157.3 million and $61.6 million, respectively, and proceeds from asset sales were $14.8 million and $24.8 million, respectively.

Net cash provided by (used in) financing activities. During the year ended December 31, 2018, we borrowed $230.5 million, on a net basis, to support our purchases of new compression units, reconfiguration costs and related equipment as well as fund certain costs associated with the CDM Acquisition. During the year ended December 31, 2018, we received $479.1 million in net proceeds from the issuance of Preferred Units and Warrants which was used to partially fund the CDM Acquisition and a $28.5 million contribution from the USA Compression Predecessor's former parent company, ETP. Additionally, and in connection with the CDM Acquisition, we paid various fees of $17.7 million related primarily to the Credit Agreement. During the year ended December 31, 2018, we also paid cash related to the net settlement of unit-based equity awards under our long-term incentive plan in the amount of $4.4 million, made cash distributions to our common unitholders of $142.3 million and made cash distributions on the Preferred Units of $24.2 million.

For the years ended December 31, 2017 and 2016, net cash used in financing activities reflected the payment of cash distributions to the USA Compression Predecessor's former parent company, ETP, of $3.7 million and $90.4 million, respectively.

Capital Expenditures

The compression services 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:

- 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, 2018 and 2017 were $32.5 million and $21.0 million, respectively. We currently plan to spend approximately $25 million in maintenance capital expenditures during 2019, including parts consumed from inventory.

Given our growth objectives and anticipated demand from our customers as a result of the increasing natural gas activity described above under the heading “—General Trends and Outlook,” we anticipate that we will continue to make significant expansion capital expenditures. Without giving effect to any equipment we may acquire pursuant to any future acquisitions, we currently have budgeted between $140 million and $150 million in expansion capital expenditures during 2019. Our expansion capital expenditures for the years ended December 31, 2018 and 2017 were $208.7 million and $154.5 million, respectively.

Revolving Credit Facility

As of December 31, 2018, we were in compliance with all of our covenants under the Credit Agreement. As of December 31, 2018, we had outstanding borrowings under the Credit Agreement of $1.1 billion, $550.5 million of borrowing base availability and, subject to compliance with the applicable financial covenants, available borrowing capacity of $550.5 million. As described in Note 10 to our consolidated financial statements, we entered into the Credit Agreement on the Transactions Date, which amended the Fifth Amended and Restated Credit Agreement to, among other things, (i) increase the borrowing capacity under the Credit Agreement from $1.1 billion to $1.6 billion (subject to availability under a borrowing base), (ii) extend the termination date (and the maturity date of the obligations thereunder) from January 6, 2020 to April 2, 2023, (iii) subject to the terms of the Credit Agreement, permit up to $400.0 million of future increases in borrowing capacity, (iv) modify the leverage ratio covenant to be 5.75 to 1.0 through the end of the fiscal quarter ending March 31, 2019, 5.5 to 1.0 through the end of the fiscal quarter ending December 31, 2019, and 5.0 to 1.0 thereafter and (v) increase the applicable margin for eurodollar borrowings to range from 2.00% to 2.75%, depending on our leverage ratio, all as more fully set forth in the Credit Agreement.

As of February 14, 2019, we had outstanding borrowings of $1.1 billion. We expect to remain in compliance with our covenants under the Credit Agreement throughout 2019. If our current cash flow projections prove to be inaccurate, we expect to be able to remain in compliance with such financial covenants by taking one or more of the following actions: issue debt and equity securities 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 the Credit Agreement.

For a more detailed description of the Credit Agreement including the covenants and restrictions contained therein, please refer to Note 10 to our consolidated financial statements.

Senior Notes

See Note 10 to our consolidated financial statements for information regarding the Senior Notes.

Distribution Reinvestment Plan

During the year ended December 31, 2018, distributions of $0.6 million were reinvested under the DRIP resulting in the issuance of 39,280 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 12 to our consolidated financial statements.

Total Contractual Cash Obligations

The following table summarizes our total contractual cash obligations as of December 31, 2018:

	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)	$ 1,774,547	$ —	$ —	$ 1,049,547	$ 725,000
Interest on long-term debt obligations (2)	591,376	101,964	203,929	169,182	116,302
Equipment/capital purchases (3)	107,457	107,457	—	—	—
Operating and capital lease obligations (4)	7,910	3,773	2,417	1,078	642
Total contractual cash obligations	$ 2,481,290	$ 213,194	$ 206,346	$ 1,219,807	$ 841,944

(1) We assumed that the amount outstanding under the Credit Agreement at December 31, 2018 would be repaid in April 2023, the maturity date of the facility. The aggregate principal amount of our Senior Notes outstanding is due April 2026.
(2) Represents future interest payments under the Credit Agreement based on the interest rate as of December 31, 2018 of 4.97% and on $725.0 million aggregate principal amount of the Senior Notes.
(3) Represents commitments for new compression units that are being fabricated, and is a component of our overall projected expansion capital expenditures during 2019 of $140 million to $150 million.
(4) Represents commitments for future minimum lease payments on noncancelable operating and capital 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.

Table of Contents

Off-Balance Sheet Arrangements

We have no off-balance sheet financing activities. Please refer to Note 17 to 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 when obligations under the terms of a contract with our customer are satisfied; generally this occurs with the transfer of our services or goods. Revenue is measured at the amount of consideration we expect to receive in exchange for providing services or transferring goods. Sales taxes incurred on behalf of, and passed through to, customers are excluded from revenue. Incidental items, if any, that are immaterial in the context of the contract are recognized as expense.

Contract operations revenue

Revenue from contracted compression, station, gas treating and maintenance services is recognized ratably under our fixed-fee contracts over the term of the contract as services are provided to our customers. Initial contract terms typically range from six months to five years. However, we usually 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 fixed-fee contracts whereby our customers are required to pay our monthly fee even during periods of limited or disrupted throughput. Services are generally 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, and payment is generally due 30 days after receipt of our invoice. Amounts invoiced in advance are recorded as deferred revenue until earned, at which time they are recognized as revenue. The amount of consideration we receive and revenue we recognize is based upon the fixed fee rate stated in each service contract.

Retail parts and services revenue

Retail parts and services revenue is earned primarily on freight and crane charges that are directly reimbursable by our customers and maintenance work on units at our customers' locations that are outside the scope of our core maintenance activities. Revenue from retail parts and services is recognized at the point in time the part is transferred or service is provided and control is transferred to the customer. At such time, the customer has the ability to direct the use of the benefits of such part or service after we have performed our services. We bill upon completion of the service or transfer of the parts, and payment is generally due 30 days after receipt of our invoice. The amount of consideration we receive and revenue we recognize is based upon the invoice amount.

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 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.

As of October 1, 2018, we performed our annual goodwill impairment analysis which included a qualitative assessment and concluded that it is not more likely than not that the fair value of our single reporting unit was less than its carrying value and that our goodwill was not impaired. As a result, we recorded no goodwill impairment charges for the year ended December 31, 2018. We had approximately $619.4 million of goodwill recorded on the balance sheet as of December 31, 2018.

For the year ended December 31, 2017, the USA Compression Predecessor performed a quantitative assessment for its annual goodwill impairment test and determined its fair value using a weighted combination of the discounted cash flow method and the guideline company method. Determining the fair value of a reporting unit requires judgment and the use of significant estimates and assumptions. Such estimates and assumptions include revenue growth rates, operating margins, weighted average costs of capital and future market conditions, among others. The USA Compression Predecessor believed the estimates and assumptions used in the impairment assessment were reasonable and based on available market information, but variations in any of the assumptions could have resulted in materially different calculations of fair value and determinations of whether or not an impairment is indicated. Under the discounted cash flow method, the USA Compression Predecessor determined fair value based on estimated future cash flows including estimates for capital expenditures, discounted to present value using the risk-adjusted industry rate, which reflects the overall level of inherent risk of the company. Cash flow projections were derived from one year budgeted amounts and five year operating forecasts plus an estimate of later period cash flows, all of which were developed by management. Subsequent period cash flows were developed using growth rates that management believed were reasonably likely to occur. Under the guideline company method, the USA Compression Predecessor determined its estimated fair value by applying valuation multiples of comparable publicly-traded companies to the projected EBITDA of the company and then averaging that estimate with similar historical calculations using a three-year average. In addition, the USA Compression Predecessor estimated a reasonable control premium representing the incremental value that accrues to the predecessor's majority owner from the opportunity to dictate the strategic and operational actions of the business. Additionally, the USA Compression Predecessor considered the presence and probability of subsequent events on market transactions in estimating the fair value of the company, such as the Transactions discussed in Note 1 to our consolidated financial statements.

One key assumption for the measurement of goodwill impairment is management's estimate of future cash flows and EBITDA. These estimates are based on the annual budget for the upcoming year and forecasted amounts for multiple subsequent years. The annual budget process is typically completed near the annual goodwill impairment testing date, and management uses the most recent information for the annual impairment tests. The forecast is also subjected to a comprehensive update annually in conjunction with the annual budget process and is revised periodically to reflect new information and/or revised expectations.

Based on the completion of the annual goodwill impairment testing as described above, the USA Compression Predecessor recorded a $223.0 million impairment for the year ended December 31, 2017. The USA Compression

Table of Contents

Predecessor had approximately $253.4 million of goodwill remaining on the balance sheet as of December 31, 2017 following this impairment. There was no goodwill impairment for the year ended December 31, 2016.

As discussed above, estimates of fair value can be affected by a variety of external and internal factors. Volatility in crude oil prices can cause 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 $619.4 million balance 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.

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 doubtful accounts 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.

Recent Accounting Pronouncements

For a discussion on specific recent accounting pronouncements affecting us, please see Note 18 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. Natural gas or crude oil prices remaining low 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, 2018 would have resulted in a decrease of approximately $5.3 million and $3.4 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, 2018, we had approximately $1.1 billion of variable-rate outstanding indebtedness at a weighted-average interest rate of 4.69%. A 1% increase or decrease in the effective interest rate on our variable-rate outstanding debt as of December 31, 2018 would result in an annual increase or decrease in our interest expense of approximately $10.5 million.

For further information regarding our exposure to interest rate fluctuations on our debt obligations, see Note 10 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.

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 amount it owes us, it 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

Table of Contents

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, 2018 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, 2018. 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, 2018, our internal control over financial reporting was effective. Grant Thornton LLP, an independent registered public accounting firm, has audited the effectiveness of our internal control over financial reporting as of December 31, 2018, as stated in their report, which is included herein.

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors of USA Compression GP, LLC and

Unitholders of USA Compression Partners, LP

Opinion on internal control over financial reporting

We have audited the internal control over financial reporting of USA Compression Partners, LP (a Delaware limited partnership) and subsidiaries (the “Partnership”) as of December 31, 2018, based on criteria established in the 2013 Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”). In our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in the 2013 Internal Control—Integrated Framework issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (“PCAOB”), the consolidated financial statements of the Partnership as of and for the year ended December 31, 2018, and our report dated February 19, 2019 expressed an unqualified opinion on those financial statements.

Basis for opinion

The Partnership’s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management’s Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Partnership’s internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and limitations of internal control over financial reporting

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ GRANT THORNTON LLP

Houston, Texas

February 19, 2019

Table of Contents

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

On February 13, 2019, the Board approved the USA Compression Partners, LP Amended and Restated Annual Cash Incentive Plan (the “A&R Bonus Plan”). See “Part III—Item 11. Executive Compensation—Compensation Discussion & Analysis—Annual Cash Incentive Compensation for 2019” for a description of the A&R Bonus Plan; such description does not purport to be complete and is qualified by reference to the A&R Bonus Plan, which is filed as Exhibit 10.21 hereto and is incorporated herein by reference.

Table of Contents

PART III

ITEM 10.Directors, Executive Officers and Corporate Governance

Board of Directors

Our general partner, USA Compression GP, LLC (the “General Partner”), manages our operations and activities. As a result of several transactions (the “Transactions”) that closed on April 2, 2018 (the “Transactions Date”), the General Partner is solely owned by Energy Transfer Operating, L.P. (“ETO”), a wholly owned subsidiary of Energy Transfer LP (“ET” and, collectively with ETO and their affiliates, “Energy Transfer”). The General Partner has a board of directors (the “Board”) that manages our business. The Board is not elected by our unitholders and is not subject to re-election on a regular basis in the future. As the sole member of the General Partner, ETO is entitled under the limited liability company agreement of the General Partner (the “GP LLC Agreement”) to appoint all directors of the General Partner, subject to rights and restrictions contained in other agreements. The GP LLC Agreement provides that the Board shall consist of between two and nine persons, at least two of whom are required to meet the independence standards required of directors who serve on an audit committee of a board of directors established by the Securities Exchange Act of 1934, as amended (the “Exchange Act”), and the rules and regulations of the SEC thereunder, and by the NYSE pertaining to qualification for service on an audit committee.

Prior to the Transactions Date, the Board was comprised of eight members, and Eric D. Long, our President and Chief Executive Officer (“CEO”), is the only director who remained on the Board subsequent to the Transactions Date. Effective as of the Transactions Date, the Board is comprised of nine members, eight of whom were designated by ETO and one of whom was designated by EIG Management Company, LLC (“EIG Management”) pursuant to that certain Board Representation Agreement among us, the General Partner, Energy Transfer Equity, L.P. (whose wholly owned subsidiary, Energy Transfer Partners, L.L.C. acquired the General Partner in the Transactions and subsequently contributed it to ETO in connection with a merger among several Energy Transfer entities that closed in October 2018) and EIG Veteran Equity Aggregator, L.P. (along with its affiliated funds, “EIG”) on the Transactions Date in connection with our private placement to EIG and FS Energy and Power Fund (“FS Energy”) of Series A Preferred Units in the Partnership (the “Preferred Units”) and warrants to purchase common units of the Partnership (the “Warrants”). Under the Board Representation Agreement, EIG Management has the right to designate one member of the Board for so long as EIG and FS Energy own, in the aggregate, more than 5% of the Partnership’s outstanding common units (taking into account the common units issuable upon conversion of the Preferred Units and exercise of the Warrants). Three members of the Board are independent as defined under the independence standards established by the NYSE and the SEC. Although the NYSE does not require a publicly traded limited partnership like us to have a majority of independent directors on the Board or to establish a compensation committee or a nominating committee, the Board has elected to have a standing compensation committee (the “Compensation Committee”). We do not have a nominating committee in light of the fact that ETO and EIG currently collectively appoint all of the members of the Board.

Our CEO is currently the only management member of the Board. The non-management members of the Board meet in executive session without any members of management present at least twice a year. Mr. William S. Waldheim presides at such meetings. Interested parties can communicate directly with non-management members of the Board 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 similar communications will not be forwarded to the Board.

As a limited partnership, NYSE rules do not require us to seek unitholder approval for the election of any of our directors. We do not have a formal process for identifying director nominees, nor do we have a formal policy regarding consideration of diversity in identifying director nominees. We believe, however, that the individuals appointed as directors have experience, skills and qualifications relevant to our business and have a history of service in senior leadership positions with the qualities and attributes required to provide effective oversight of the Partnership.

Independent Directors. The Board has determined that Matthew S. Hartman, Glenn E. Joyce and William S. Waldheim are independent directors under the standards established by the NYSE and the Securities Exchange Act of 1934 (the “Exchange Act”). The Board considered all relevant facts and circumstances and applied the independence guidelines of the NYSE and the Exchange Act in determining that none of these directors has any material relationship with us, our management, the General Partner or its affiliates or our subsidiaries.

Mr. Hartman is a Managing Director at EIG, and, since the Transactions Date, EIG owns over 80% of the Preferred Units and Warrants in the Partnership. The Board determined that EIG's ownership of Preferred Units and Warrants did not preclude the independence of Mr. Hartman because (i) the Preferred Units and Warrants do not confer voting rights sufficient to participate in the control of the Partnership or influence its management, (ii) the Board Representation Agreement does not grant to EIG a sufficient number of seats on the Board to significantly influence or control its decision making or materially influence the management or operation of the Partnership and (iii) the Board has determined that ownership of even a significant amount of the Partnership's securities does not, by itself, preclude a finding of independence. In addition, Mr. Hartman serves on the board of directors of one of our customers, Southcross Holdings GP LLC ("Southcross"). During the period of Mr. Hartman's directorship during 2018, Southcross made compression service payments to us of approximately $0.3 million. The Board determined that Mr. Hartman's relationship with Southcross did not preclude his independence.

Prior to the Transactions, the Board included the following directors that it had determined were independent under the standards established by the NYSE and the Exchange Act: Robert F. End, Jerry L. Peters and Forrest E. Wylie. Mr. Peters served on the Board from October 2017 until the Transactions Date, and since September 2012, Mr. Peters also served on the board of directors and the audit committee of one of our customers. During the period of Mr. Peters' directorship during 2018, subsidiaries of this customer made compression service payments to us of approximately $0.3 million. The Board previously determined that Mr. Peters' relationship with this customer did not preclude his independence. Each of Messrs. End, Peters and Wylie resigned effective the Transactions Date in connection with the Transactions.

The Board's Role in Risk Oversight

The Board administers its risk oversight function as a whole and through its committees. It does so in part through discussion and review of our business, financial reporting and corporate governance policies, procedures and practices, with opportunity to make specific inquiries of management. In addition, at each regular meeting of the Board, management provides a report of the Partnership's operational and financial performance, which often prompts questions and feedback from the Board. The audit committee of the Board (the "Audit Committee") provides additional risk oversight through its quarterly meetings, where it discusses policies with respect to risk assessment and risk management, reviews contingent liabilities and risks that may be material to the Partnership and assesses major legislative and regulatory developments that could materially impact the Partnership's contingent liabilities and risks. The Audit Committee is also required to discuss any material violations of our policies brought to its attention on an ad hoc basis. Additionally, the Compensation Committee reviews our overall compensation program and its effectiveness at both linking executive pay to performance and aligning the interests of our executives and our unitholders.

Committees of the Board of Directors

Audit Committee. The Board appoints the Audit Committee, which is comprised solely of directors who meet the independence and experience standards established by the NYSE and the Exchange Act. The Audit Committee consists of Messrs. Hartman, Joyce and Waldheim, and Mr. Waldheim serves as chairman of the Audit Committee. The Board determined that Mr. Waldheim is an “audit committee financial expert” as defined in Item 407(d)(5)(ii) of SEC Regulation S-K, and that each of Messrs. Hartman, Joyce and Waldheim is “independent” within the meaning of the applicable NYSE and Exchange Act rules governing audit committee independence. The Audit Committee assists the Board in its oversight of the integrity of our financial statements and our compliance with legal and regulatory requirements as well as the effectiveness of our corporate policies and internal 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 is given unrestricted access to the Audit Committee.

Table of Contents

In April 2018, the Audit Committee recommended that the Board approve an amended and restated Audit Committee charter (the "A&R Audit Committee Charter") that is based on Energy Transfer's audit committee charter, and in May 2018 the Board approved the A&R Audit Committee Charter. The A&R Audit Committee Charter is available under the Investor Relations tab on our website at usacompression.com. We will provide a copy of the A&R Audit Committee Charter to any of our unitholders without charge upon written request to Investor Relations, 100 Congress Avenue, Suite 450, Austin, TX 78701.

Compensation Committee. The NYSE does not require a listed limited partnership like us to have a compensation committee. However, the Board established the Compensation Committee to, among other things, oversee our compensation program described below in Part III, Item 11 "Executive Compensation." The Compensation Committee consists of Messrs. Joyce and Waldheim and is chaired by Mr. Joyce. The Compensation Committee establishes and reviews general policies related to our compensation and benefits and is responsible for making recommendations to the Board with respect to the compensation and benefits of the Board. In addition, the Compensation Committee administers the USA Compression Partners, LP 2013 Long-Term Incentive Plan, as amended and as may be further amended or replaced from time to time (the "LTIP").

In February 2019, the Compensation Committee recommended that the Board approve, and the Board approved, an amended and restated Compensation Committee charter (the "A&R Compensation Committee Charter") that is based on Energy Transfer's compensation committee charter. Under the A&R Compensation Committee Charter, a director serving as a member of the Compensation Committee may not be an officer of or employed by the General Partner, us or our subsidiaries. During 2018, neither Mr. Joyce nor Mr. Waldheim was an officer or employee of Energy Transfer or any of its affiliates, or served as an officer of any company with respect to which any of our executive officers served on such company's board of directors. In addition, neither Mr. Joyce nor Mr. Waldheim is a former employee of Energy Transfer or any of its affiliates.

The A&R Compensation Committee Charter is available under the Investor Relations tab on our website at usacompression.com. We will provide a copy of the A&R Compensation Committee Charter 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 GP LLC Agreement, the General Partner may, from time to time, establish a conflicts committee to which the Board will appoint independent directors and which may be asked to review specific matters that the Board believes may involve conflicts of interest between us, our limited partners and Energy Transfer. Such conflicts committee will determine the resolution of the conflict of interest in any matter referred to it in good faith. The members of the conflicts committee may not be officers or employees of the General Partner or directors, officers or employees of its affiliates, including Energy Transfer, and must meet the independence and experience standards established by the NYSE and the Exchange Act to serve on the Audit Committee, 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 the General Partner of any duties it may owe us or our unitholders.

Corporate Governance Guidelines and Code of Ethics

The Board has adopted Corporate Governance Guidelines (the “Guidelines”) that outline important policies and practices regarding our governance and provide a framework for the function of the Board and its committees. In February 2019, the Board approved certain amendments to the Guidelines to reflect current Board practices since the Transactions. The Board has also adopted a Code of Business Conduct and Ethics (the “Code”) that applies to the 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. We intend to post any amendments to the Code, or waivers of its provisions applicable to our directors or executive officers, including our principal executive officer and principal financial officer, on our website. The Guidelines and the Code are available under the Investor Relations tab on our website at usacompression.com. We will provide copies of the 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.

Note that the preceding internet addresses are for informational purposes only and are not intended to be hyperlinked. Accordingly, no information found on or provided at those internet addresses or on our website in general is intended or deemed to be incorporated by reference herein.

Directors and Executive Officers

The following table shows information as of February 14, 2019 regarding the current directors and executive officers of USA Compression GP, LLC.

Name	Age	Position with USA Compression GP, LLC
Eric D. Long	60	President and Chief Executive Officer and Director
Matthew C. Liuzzi	44	Vice President, Chief Financial Officer and Treasurer
William G. Manias	56	Vice President and Chief Operating Officer
David A. Smith	56	Vice President and President, Northeast Region
Sean T. Kimble	54	Vice President, Human Resources
Christopher W. Porter	35	Vice President, General Counsel and Secretary
Michael Bradley	64	Director
Christopher R. Curia	63	Director
Matthew S. Hartman	38	Director
Glenn E. Joyce	61	Director
Thomas E. Long	62	Director
Thomas P. Mason	62	Director
Matthew S. Ramsey	63	Director
William S. Waldheim	62	Director

The directors of the 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. There are no family relationships among any of the directors or executive officers of the General Partner.

Eric D. Long has served as our President and CEO since September 2002 and has served as a director of the General Partner 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.

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.

William G. Manias has served as our Vice President and Chief Operating Officer since July 2013. He served as a director of the 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 Products 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 Products Partners L.P. Prior to GulfTerra Energy Partners, L.P., Mr. Manias 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.

David A. Smith has served as our President, Northeast Region since joining us in November 1998 and was appointed as a Vice President of the General Partner 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 associate's 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 brings to us over twenty-five years of human resources leadership experience. Prior to joining us, 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. in marketing from Sacramento State University and an M.B.A. from Saint Mary's College of California. Mr. Kimble also completed the University of Michigan's Strategic HR and Strategic Collective Bargaining Programs.

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 Hunton Andrews Kurth 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 in accounting from Texas A&M University, a M.S. degree in finance from Texas A&M University, and a J.D. degree from The George Washington University.

Michael Bradley has served on the Board since April 2018. Mr. Bradley currently serves as the Executive Vice President—LNG & International Business Development at ETO. He served on the board of directors of Regency GP, LLC, the general partner of Regency Energy Partners LP ("Regency") and as the President and Chief Executive Officer of Regency until its merger with ETP in May 2015. Prior to joining Regency, he served as President, Chief Executive

Officer and a director of Matrix Service Company. Prior to joining Matrix Service Company, Mr. Bradley served as President and Chief Executive Officer of DCP Midstream Partners, LP ("DCP Midstream") and as a member of the board of its general partner. Mr. Bradley also previously served as Group Vice President of Gathering and Processing for Duke Energy Field Services ("DEFS") and Executive Vice President of DEFS and Senior Vice President of DEFS. Mr. Bradley holds a bachelor's degree in civil engineering from the University of Kansas and completed the Duke University Executive Management Program. Mr. Bradley is a member of the American Society of Civil Engineers and serves on the advisory board for the University of Kansas School of Engineering.

Mr. Bradley was selected to serve on the Board due to his many years of experience in the natural gas industry and midstream energy sector and proven record of effective executive level leadership.

Christopher R. Curia has served on the Board since April 2018. Mr. Curia has also served as a director on the board of directors of the general partner of Sunoco LP (NYSE: SUN) since August 2014 and as its Executive Vice President-

Human Resources since April 2015. Mr. Curia also serves as the Executive Vice President and Chief Human Resources Officer of LE GP, LLC (“LE GP”), the general partner of Energy Transfer LP (“ET LP”) and has served in that capacity since January 2015. Mr. Curia joined ETO in July 2008 and was appointed the Executive Vice President and Chief Human Resources Officer of ET LP in January 2015. Prior to joining Energy Transfer, Mr. Curia held HR leadership positions at both Valero Energy Corporation and Pennzoil and has more than three decades of Human Resources experience in the oil and gas field. Mr. Curia holds a master’s degree in Industrial Relations from the University of West Virginia.

Mr. Curia was selected to serve on the Board due to the valuable perspective he brings from his extensive experience working as a human resources professional in the energy industry, and the insights he brings to the Board on matters such as succession planning, compensation, employee management and acquisition evaluation and integration.

Matthew S. Hartman has served on the Board since April 2018. Mr. Hartman is a Managing Director at EIG Global Energy Partners and is the co-head of EIG’s midstream investment team. In this capacity, he invests in and monitors energy midstream investments. Mr. Hartman also serves on the board of directors of Southcross Holdings GP LLC. Prior to joining EIG in 2014, Mr. Hartman served in various roles within the Citigroup and UBS investment banking divisions, where he advised on mergers as well as equity and debt financings for midstream energy companies. Mr. Hartman also previously worked in Ernst & Young’s tax practice. Mr. Hartman received a B.B.A. and B.P.A. from Oklahoma Baptist University and an M.B.A. from the University of Texas.

Mr. Hartman was selected to serve on the Board because of his financial and investment acumen and experience with the midstream energy sector.

Glenn E. Joyce has served on the Board since April 2018. Mr. Joyce has served as Chief Administrative Officer of Apex International Energy (“Apex”) since January 2017. He previously served as Director – HR and Administration since he joined Apex in April 2016. Prior to joining Apex, he spent over 17 years with Apache Corporation where his last position was Director of Global Human Resources in which he managed the HR functions of the international regions of Apache (Australia, Argentina, UK, Egypt). Previously, he worked for Amoco and was involved in international operations in many different countries. Mr. Joyce received his bachelor’s degree in accounting from Texas A&M University.

Mr. Joyce was selected to serve on the Board due to his extensive experience in senior human resources leadership positions in the energy industry.

Thomas E. Long has served on the Board since April 2018. He has also served on the board of directors of the general partner of Sunoco LP since May 2016. Mr. Long was appointed the Chief Financial Officer of the general partner of ET LP following the merger of ETE and ETP in October 2018 and prior to the merger he was the Group Chief

Financial Officer since February 2016. Mr. Long previously served as Chief Financial Officer of ETO’s general partner and as Executive Vice President and Chief Financial Officer of Regency Energy Partners LP’s general partner from November 2010 to April 2015. From May 2008 to November 2010, Mr. Long served as Vice President and Chief Financial Officer of Matrix Service Company. Prior to joining Matrix, he served as Vice President and Chief Financial Officer of DCP Midstream, a publicly traded natural gas and natural gas liquids midstream business company located in Denver, Colorado. In that position, he was responsible for all financial aspects of the company since its formation in December 2005. From 1998 to 2005, Mr. Long served in several executive positions with subsidiaries of Duke Energy Corp., one of the nation’s largest electric power companies. Mr. Long has a Bachelor of Arts in Accounting and is a Certified Public Accountant.

Mr. Long was selected to serve on the Board because of his understanding of energy-related corporate finance gained through his extensive experience in the energy industry.

Thomas P. Mason has served on the Board since April 2018. Mr. Mason was appointed Executive Vice President, General Counsel & President – LNG of LE GP after the merger of ETE and ETP in October 2018. Prior to the merger he was Executive Vice President and General Counsel of the general partner of ETE. Mr. Mason previously served as Senior Vice President, General Counsel and Secretary of ETO’s general partner from April 2012 to December 2015, as

Vice President, General Counsel and Secretary from June 2008 and as General Counsel and Secretary from February 2007. Prior to joining Energy Transfer, he was a partner in the Houston office of Vinson & Elkins L.L.P. Mr. Mason has specialized in securities offerings and mergers and acquisitions for more than 25 years. Mr. Mason also previously served on the Board of Directors of the general partner of Sunoco Logistics Partners L.P.

Mr. Mason was selected to serve on the Board because of his decades of legal experience in securities, mergers and acquisitions and corporate governance in the energy sector.

Matthew S. Ramsey has served on the Board since April 2018. Mr. Ramsey has also served on the board of directors of the general partner of SUN since August 2014, and as the chairman of the board of directors of the general partner of SUN since April 2015. Mr. Ramsey is the Chief Operating Officer and director of ET LP’s general partner and has served in that capacity since the completion of the merger of ETE and ETP in October 2018. Mr. Ramsey served as President and Chief Operating Officer of ETO’s general partner from November 2015 until the merger between ETE and ETP in October 2018. Mr. Ramsey has served on the board of directors of the general partner of ETO since July 2012. Mr. Ramsey served as President and Chief Operating Officer and Chairman of the board of directors of PennTex Midstream Partners, LP’s general partner from November 2016 until ETP completed its acquisition of PennTex in June 2017. Prior to joining Energy Transfer in November 2015, Mr. Ramsey served as president of Houston-based RPM Exploration Ltd., a private oil and gas exploration partnership generating and drilling 3-D seismic prospects on the Gulf Coast of Texas. Mr. Ramsey is currently a director of RSP Permian, Inc. (NYSE: RSPP), where he serves as chairman of the compensation committee and as a member of the audit committee. Mr. Ramsey formerly served as President of DDD Energy, Inc. until its sale in 2002. From 1996 to 2000, Mr. Ramsey served as President and Chief Executive Officer of OEC Compression Corporation, Inc., a publicly traded oil field service company, providing gas compression services to a variety of energy clients. Mr. Ramsey holds a B.B.A. in Marketing from the University of Texas at Austin and a J.D. from South Texas College of Law. Mr. Ramsey is a graduate of the Harvard Business School Advanced Management Program. Mr. Ramsey is licensed to practice law in the State of Texas. He is qualified to practice in the Western District of Texas and the United States Court of Appeals for the Fifth Circuit. Mr. Ramsey formerly served as a director of Southern Union Company.

Mr. Ramsey was selected to serve on the Board in recognition of his vast knowledge of the energy space and valuable industry, operational and management experience.

William S. Waldheim has served on the Board since April 2018. Mr. Waldheim served as a director and a member of the Audit, Finance & Risk Committee of Enbridge Energy Company, Inc. and Enbridge Energy Management, L.L.C. from February 2016 through December 2018. He previously served as President of DCP Midstream where he had overall responsibility for DCP Midstream’s affairs including commercial, trading and business development until his retirement in 2015. Prior to this, Mr. Waldheim was President of Midstream Marketing and Logistics for DCP Midstream and managed natural gas, crude oil and natural gas liquids marketing and logistics. From 2005 to 2008, he was Group Vice President of Commercial for DCP Midstream, managing its upstream and downstream commercial business. Mr. Waldheim started his professional career in 1978 with Champlin Petroleum as an auditor and financial analyst and served in roles involving NGL and crude oil distribution and marketing. He served as Vice President of NGL and Crude Oil Marketing for Union Pacific Fuels from 1987 until 1998 at which time it was acquired by DCP

Midstream.

Mr. Waldheim was selected to serve on the Board because of his broad and extensive experience in senior leadership roles in the energy industry and his financial and accounting expertise.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires that the members of the Board, our executive officers and persons who own more than 10 percent of a registered class of our equity securities file initial reports of ownership and reports of changes in ownership of our common units and other equity securities with the SEC and any exchange or other system on which such securities are traded or quoted. SEC regulations also require that the members of the Board, our executive officers and persons who own greater than 10 percent of a registered class of our equity securities furnish to us and any exchange or other system on which such securities are traded or quoted copies of all Section 16(a) forms they have filed with the SEC. To our knowledge and based solely on a review of the copies of such reports furnished to us, we believe

Table of Contents

that all reporting obligations of the members of the Board, our executive officers and greater than 10 percent unitholders under Section 16(a) were satisfied during the year ended December 31, 2018.

Common Unit Ownership by Directors and Executive Officers

We encourage our directors and executive officers to invest in and retain ownership of our common units, but we do not require such individuals to establish and maintain a particular level of ownership.

Reimbursement of Expenses of the General Partner

The General Partner does not receive any management fee or other compensation for its management of us, but we reimburse the General Partner and its affiliates for all expenses incurred on our behalf, including the compensation of employees of the General Partner or its affiliates that perform services on our behalf. These expenses include all expenditures necessary or appropriate to the conduct of our business and that are allocable to us. The Second Amended and Restated Agreement of Limited Partnership of USA Compression Partners, LP (the “Partnership Agreement”) provides that the 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 the General Partner or its affiliates for compensation or expenses incurred on our behalf.

ITEM 11.Executive Compensation

As is commonly the case with publicly traded limited partnerships, we have no officers, directors or employees. Under the terms of the Partnership Agreement, we are ultimately managed by the General Partner, which is controlled by Energy Transfer. All of our employees, including our executive officers, are employees of USA Compression Management Services, LLC (“USAC Management”), a wholly owned subsidiary of the General Partner. References to “our officers” and “our directors” refer to the officers and directors of the General Partner.

Compensation Discussion & Analysis

Named Executive Officers

The following disclosure describes the executive compensation program for the named executive officers identified below (the "NEOs"). For the year ended December 31, 2018, the NEOs were:

- Eric D. Long, President and CEO;
- Matthew C. Liuzzi, Vice President, Chief Financial Officer and Treasurer;
- William G. Manias, Vice President and Chief Operating Officer;
- David A. Smith, Vice President and President, Northeast Region; and
- Sean T. Kimble, Vice President, Human Resources.

Compensation Philosophy and Objectives

Since our initial public offering in 2013, we have consistently based our compensation philosophy and objectives on the premise that a significant portion of each NEO's total compensation should be incentive-based or "at-risk" compensation. We share Energy Transfer's philosophy that the NEOs' total compensation levels should be competitive in the marketplace for executive talent and abilities. The Compensation Committee generally targets at or near the 50th percentile of the market for the three main components of our compensation program: base salary, annual discretionary cash bonus and long-term equity incentive awards. The Compensation Committee believes the incentive-based balance is achieved by (i) the payment of annual discretionary cash bonuses that consider (a) the achievement of the financial performance objectives for a fiscal year set at the beginning of such fiscal year and (b) the individual contributions of each of the NEOs to our level of success in achieving the annual financial performance objectives, and (ii) the annual grant of time-based restricted phantom unit awards under the LTIP, which awards are intended to incentivize and retain our key employees for the long-term and motivate them to focus their efforts on increasing the market price of our common units and the level of cash distributions we pay to our common unitholders.

Table of Contents

The following charts illustrate the level of at-risk incentive compensation we awarded in 2018 to our CEO and, on an averaged basis, the other NEOs. "Variable/at-risk" compensation is comprised of long-term equity incentive awards and annual discretionary cash bonuses, and "fixed" compensation is comprised of base salary.

Our compensation program is structured to achieve the following:

- compensate executives with an industry-competitive total compensation package of competitive base salaries and significant incentive opportunities yielding a total compensation package at or near the 50th percentile of the market;
- attract, retain and reward talented executive officers and key members of management by providing a total compensation package competitive with those of their counterparts at similarly situated companies;
- motivate executive officers and key employees to achieve strong financial and operational performance;
- emphasize performance-based or "at risk" compensation; and
- reward individual performance.

Methodology to Setting Compensation Packages

Our executive compensation program is administered by the Compensation Committee. The Compensation Committee considers market trends in compensation, including the practices of identified competitors, and the alignment of the compensation program with the Partnership's strategy. Specifically, for the NEOs, the Compensation Committee:

- establishes and approves target compensation levels for each NEO;
- approves Partnership performance measures and goals;
- determines the mix between cash and equity compensation, short-term and long-term incentives and benefits;
- verifies the achievement of previously established performance goals; and
- approves the resulting cash or equity awards to the NEOs.

The Compensation Committee also considers other factors such as the role, contribution and performance of an individual relative to his or her peers at the Partnership. The Compensation Committee does not assign specific weight to these factors, but rather makes a subjective judgment taking all of these factors into account.

The Compensation Committee reviews and approves all compensation for the NEOs. In determining the compensation for the NEOs, the Compensation Committee takes into account input from the CEO for the compensation of the other NEOs. The CEO considers comparative compensation data and evaluates the individual performance of each NEO and their respective contributions to the Partnership. The recommendations are then reviewed by the Compensation Committee, which may accept the recommendations or make adjustments to the recommended compensation based on

Table of Contents

the Compensation Committee's assessment of the individual's performance and contributions to the Partnership. The CEO's compensation is reviewed and approved by the Compensation Committee based on comparative compensation data and the Compensation Committee's independent evaluation of the CEO's contributions to the Partnership's performance.

Periodically, we engage a third-party consultant to provide the Compensation Committee with market information about compensation levels at peer companies to assist in setting compensation levels for our executives, including the NEOs. In 2016, the Compensation Committee engaged Longnecker & Associates ("Longnecker") to assist the Compensation Committee in determining appropriate compensation levels for senior management, including the NEOs, by: (i) providing market information for compensation levels at peer companies; (ii) evaluating the market competitiveness of our total compensation levels; and (iii) confirming that our compensation program is yielding compensation packages consistent with our overall compensation philosophy. The compensation analysis provided by Longnecker in 2016 (the "2016 Longnecker Report") covered all major components of total compensation, including annual base salary, annual short-term cash bonus and long-term equity incentive awards for the NEOs as compared to executives at similarly situated companies in terms of industry, annual revenue and market capitalization.

The Compensation Committee also benchmarked results for the annual base salary, annual short-term cash bonus and long-term equity incentive awards of the NEOs against data for compensation levels for specific executive positions reported in published executive compensation surveys within each of the (i) energy industry and (ii) overall market. The Compensation Committee also reviewed publicly filed peer group executive compensation disclosures pertaining to certain executive roles, but because of limited sample size due to the relatively small number of publicly traded natural gas compression companies, the Compensation Committee used this data as a reference point rather than a primary data source.

On November 2, 2017, the Compensation Committee determined that the 2016 Longnecker Report was completed recently enough to be utilized in setting 2018 compensation levels for the NEOs, and consulted the 2016 Longnecker Report, adjusted to account for general inflation and other relevant information obtained from other sources, such as 2018 third party survey results, in its determination of compensation levels for 2018 for our executives, including the NEOs.

In light of the Transactions and resulting increased size of the Partnership and greater level of responsibility for each of the NEOs, in May 2018 the Compensation Committee again engaged Longnecker, who is also the independent compensation advisor to Energy Transfer, to provide an updated targeted market review and benchmarking for certain members of our senior leadership team (the "2018 Longnecker Report"). The Compensation Committee relied on the results of the 2018 Longnecker Report for determinations of base salary and bonus and long-term equity incentive targets for 2019 for the NEOs.

In connection with its engagement of Longnecker, based on the information presented to it, the Compensation Committee assessed the independence of Longnecker under applicable SEC and NYSE rules and concluded that

Longnecker's work for the Compensation Committee did not raise any conflict of interest for 2018.

Table of Contents

Our 2018 peer group selected by the Compensation Committee in consultation with Longnecker included the following companies:

Company	Ticker
1. American Midstream Partners, LP	AMID
2. Archrock, Inc.	AROC
3. Buckeye Partners, L.P.	BPL
4. Crestwood Equity Partners LP	CEQP
5. Enlink Midstream, LLC	ENLC
6. EQT Midstream Partners, LP	EQM
7. Exterran Corporation	EXTN
8. Genesis Energy, L.P.	GEL
9. Martin Midstream Partners L.P.	MMLP
10. SemGroup Corporation	SEMG
11. Summit Midstream Partners, LP	SMLP
12. MPLX LP	MPLX
13. Tallgrass Energy Partners, LP	TEP
14. TETRA Technologies, Inc.	TTI

Elements of the Compensation Program

Compensation for the NEOs consists primarily of the following elements and corresponding objectives:

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.
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 the Partnership.
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 comparable to those offered by similarly situated companies.

Base Salary for 2018 and 2019

Base salaries for the 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 NEO and market conditions. In connection with determining base salaries for each of the NEOs for 2018, the Compensation Committee and CEO utilized the 2016 Longnecker Report to determine comparable salaries for such executive roles within our peer group.

Table of Contents

Following the Transactions, the Compensation Committee in consultation with Longnecker, and in consideration of the available compensation data, determined that three of the NEOs' 2018 salaries were at appropriate levels for 2019, and adjusted two of the NEOs' base salaries for 2019.

The 2018 and current 2019 base salaries for the NEOs, including our CEO, are set forth in the following table:

Name and Principal Position	2018 Base Salary ($)	Current 2019 Base Salary ($)
Eric D. Long, President and Chief Executive Officer	644,709	644,709
Matthew C. Liuzzi, Vice President, Chief Financial Officer and Treasurer	387,239	400,000
William G. Manias, Vice President and Chief Operating Officer	437,092	437,092
David A. Smith, Vice President and President, Northeast Region	502,357	517,428
Sean T. Kimble, Vice President, Human Resources	307,670	307,670

Annual Cash Incentive Compensation for 2018

The Board previously approved the USA Compression Partners, LP Annual Cash Incentive Program (the "Bonus Plan"). Each of the NEOs is entitled to participate in the Bonus Plan and their potential bonus is governed by the Bonus Plan and, for Messrs. Smith and Kimble, also governed by their respective employment agreements. The Compensation Committee acts as the administrator of the Bonus Plan under the supervision of the full Board, and has the discretion to amend, modify or terminate the Bonus Plan at any time. Although for 2018 the Bonus Plan utilized both Partnership and individual performance goals to assist in determining bonus amounts, the Bonus Plan is ultimately a discretionary annual bonus plan and awards are therefore reported in the "Bonus" column within the Summary Compensation Table below.

For the year ended December 31, 2018, the Compensation Committee set a target bonus amount (the "Target Bonus") for each NEO prior to the first quarter of the year, which was set as a percentage of the NEO's base salary. For the bonus applicable to the year ended December 31, 2018, the Target Bonus, as a percentage of base salary and as a dollar amount, is reflected in the table below.

Name	Percentage of Base Salary	Amount ($)
Eric D. Long	100%	644,709
Matthew C. Liuzzi	75%	290,429

William G. Manias	80%	349,674
David A. Smith	60%	301,346
Sean T. Kimble	70%	215,369

The Target Bonus for 2018 was generally subject to the satisfaction of both a Partnership performance goal (accounting for 75% of the Target Bonus) and an individual performance goal (accounting for 25% of the Target Bonus). Prior to 2018, seventy-five percent (75%) of the Target Bonus was subject to the Partnership's achievement of its budgeted distributable cash flow ("DCF") target for the year. For the year ended December 31, 2018, because the Partnership's predecessor for financial reporting purposes, the USA Compression Predecessor, did not historically calculate DCF on a basis directly comparable to the Partnership's calculation of DCF, the Compensation Committee determined that seventy-five percent (75%) of the Target Bonus would be instead subject to the Partnership's achievement of its budgeted Adjusted EBITDA target, as determined by the Compensation Committee. Additionally, because the Transactions closed on April 2, 2018, and prior to that Partnership management had no oversight of or involvement with the USA Compression Predecessor, the Compensation Committee determined that only the second, third and fourth quarters of 2018 (together, the "2018 Bonus Period") would be considered when determining whether the Adjusted EBITDA target had been met. For the bonus applicable to 2018, the Compensation Committee determined that, as with the previous DCF target, payouts with respect to the portion of the bonus determined by Adjusted EBITDA (the "Adjusted EBITDA Bonus") would not occur unless we satisfied the Adjusted EBITDA threshold, which was set at 80% of the Partnership's budgeted Adjusted EBITDA target. For the 2018 Bonus Period, the Compensation Committee set the budget for Adjusted EBITDA at $278.8 million. The threshold, target and maximum requirements for the Adjusted EBITDA target for the 2018 Bonus Period, as well as the portion of the Adjusted EBITDA Bonus that could

Table of Contents

become payable if Adjusted EBITDA performance was satisfied for the 2018 Bonus Period at such levels, are set forth below.

Levels of Adjusted EBITDA Bonus	Adjusted EBITDA as a Percentage of Budgeted Adjusted EBITDA for 2018 Bonus Period	Percentage of Adjusted EBITDA Bonus that would be Paid
Threshold	80%	50%
Target	100%	100%
Maximum		