Cypress Energy Partners, L.P.
Form 10-K
March 16, 2017

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

(MARK ONE)

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2016

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

FOR THE TRANSITION PERIOD FROM________ TO_______

Commission File No. 001-36260

CYPRESS ENERGY PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

Delaware	61-1721523
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**

5727 South Lewis Avenue, Suite 300	
Tulsa, Oklahoma	**74105**
(Address of principal executive offices)	(Zip Code)

(Registrant's telephone number, including area code): **(918) 748-3900**

Securities Registered Pursuant to Section 12(b) of the Act:

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

Securities Registered Pursuant to Section 12(g) of the Act: **NONE**

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes No

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

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

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

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

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

(Do not check if a smaller reporting company)

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

The aggregate market value of the registrant's Common Units Representing Limited Partner Interests held by non-affiliates computed by reference to the price at which the limited partner units were last sold as of June 30, 2016 was $41,080,196.

As of March 8, 2017, the registrant had 11,869,195 common units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE: NONE

Table of Contents

GLOSSARY OF TERMS

The following includes a description of the meanings of some of the terms used in this Annual Report on Form 10-K.

"Dig site "	The location where pipeline maintenance occurs by excavating the ground above the pipeline.
"*Flowback water*"	The fluid that returns to the surface during and for the weeks following the hydraulic fracturing process.
"*Gun barrel*"	A settling tank used for treating oil where oil and brine are separated only by gravity segregation forces.
"*Hydraulic fracturing*"	The process of pumping fluids, mixed with granular proppant, into a geological formation at pressures sufficient to create fractures in the hydrocarbon-bearing rock.
"Hydrotesting"	A process in which pressure vessels such as pipelines and fuel tanks can be tested for strength and leaks by filling the vessel with a liquid and pressurizing the vessel to the specified test pressure.
"*In-line inspection*"	An inspection technique used to assess the integrity of natural gas transmission pipelines from inside of the pipe.
"IPO"	Our initial public offering of common units representing limited partner interests in us.
"*Injection intervals*"	The part of the injection zone in which the well is screened or in which the waste is otherwise directly emplaced.
"*NGLs*"	Natural gas liquids. The combination of ethane, propane, butane, isobutene and natural gasolines that, when removed from natural gas, become liquid under various levels of higher pressure and lower temperature.
"*OPEC*"	The Organization of Petroleum Exporting Countries.
"*Pig tracking*"	The locating, mapping and monitoring of the in-line inspection pig.
"*Produced water*"	Naturally occurring water found in hydrocarbon-bearing formations that flows to the surface along with oil and natural gas.
"*Proppant*"	Sized particles mixed with fracturing fluid to hold fractures open after a hydraulic fracturing treatment.
"*Residual oil*"	Oil separated and recovered during the saltwater treatment process.
"*Separation tank*"	A cylindrical or spherical vessel used to separate oil, gas and water from the total fluid stream produced by a well.

"*Settling tank*"	A non-circulating storage tank where gravitational segregation forces separate liquids from solids.
"*Staking*"	The process of marking the location where pipeline maintenance will occur.
"*SWD*"	Salt water disposal.

NAMES OF ENTITIES

Unless the context otherwise requires, references in this Annual Report on Form 10-K to "Cypress Energy Partners, L.P.," "our partnership," "we," "our," "us," or like terms, refer to Cypress Energy Partners, L.P. and its subsidiaries.

References to:

" *Brown* " refers to Brown Integrity, LLC, a 51% owned subsidiary of CEP LLC acquired May 1, 2015;

" *CEM LLC* " refers to Cypress Energy Management, LLC, a wholly owned subsidiary of the General Partner;

" *CEM TIR* " refers to Cypress Energy Management - TIR, LLC, a wholly owned subsidiary of CEM LLC;

" *CEM-Brown* " refers to Cypress Energy Management – Brown, LLC, a wholly owned subsidiary of CEM LLC (formerly CEM-BO, Cypress Energy Management – Bakken Operations, LLC);

" *CEP LLC* " refers to Cypress Energy Partners, LLC, which became our wholly owned subsidiary at the closing of our initial public offering ("IPO");

" *CEP-TIR* " refers to Cypress Energy Partners – TIR, LLC, an indirect subsidiary of Holdings, and an owner of 1,346,800 common units representing 11.3% of our outstanding common units, and an owner of a 36.2% interest in the TIR Entities prior to the sale of its interests to the Partnership effective February 1, 2015;

" *CES LLC* " refers to Cypress Energy Services, LLC, a wholly owned subsidiary as of June 1, 2015 that performs management services for our salt water disposal ("SWD") facilities, as well as third party facilities. SBG Energy Services, LLC ("SBG Energy") owned 49% of CES LLC prior to the Partnership's June 1, 2015 acquisition of this ownership interest;

" *CF Inspection* " refers to CF Inspection Management, LLC, owned 49% by TIR-PUC and consolidated under generally accepted accounting principles by TIR-PUC. CF Inspection is 51% owned, managed and controlled by Cynthia A. Field, an affiliate of Holdings;

" *General Partner* " refers to Cypress Energy Partners GP, LLC, a subsidiary of Holdings II;

“ *Holdings* ” refers to Cypress Energy Holdings, LLC, the owner of Holdings II;

“ *Holdings II* ” refers to Cypress Energy Holdings II, LLC, the owner of 5,610,549 common units representing 47.3% of our outstanding common units;

“ *IS* ” refers to our Integrity Services business segment;

“ *Partnership* ” refers to the registrant, Cypress Energy Partners, L.P.;

“PIS” refers to our Pipeline Inspection Services business segment;

“ *TIR Entities* ” refer collectively to TIR LLC and its subsidiary; TIR Holdings and its subsidiaries and TIR-NDE, all of which were 50.1% owned by CEP LLC from our IPO until February 1, 2015, at which time CEP LLC acquired the remaining interests from affiliates of Holdings and now owns 100%;

“ *TIR Holdings* ” refers to Tulsa Inspection Resources Holdings, LLC;

“ *TIR LLC* ” refers to Tulsa Inspection Resources, LLC;

“ *TIR-PUC* ” refers to Tulsa Inspection Resources – PUC, LLC, a subsidiary of TIR LLC that has elected to be treated as a corporation for U.S. federal income tax purposes; and

“W&ES” refers to our Water and Environmental Services business segment.

CAUTIONARY REMARKS REGARDING FORWARD LOOKING STATEMENTS

The information discussed in this Annual Report on Form 10-K includes “forward-looking statements.” These forward-looking statements are identified by their use of terms and phrases such as “may,” “expect,” “estimate,” “project,” “plan,” “believe,” “intend,” “achievable,” “anticipate,” “continue,” “potential,” “should,” “could,” and similar terms and phrase Although we believe that the expectations reflected in these forward-looking statements are reasonable, they do involve certain assumptions, risks and uncertainties and we can give no assurance that such expectations or assumptions will be achieved. Important factors that could cause actual results to differ materially from those in the forward-looking statements are described under “*Item 1A - Risk Factors*” and “*Item 7 - Management’s Discussion and Analysis of Financial Condition and Results of Operations*” in this Annual Report. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the cautionary statements in this paragraph and elsewhere in this Annual Report on Form 10-K and speak only as of the date of this Annual Report on Form 10-K. Other than as required under the securities laws, we do not assume a duty to update these forward-looking statements, whether as a result of new information, subsequent events or circumstances, changes in expectations or otherwise.

PART I

ITEM 1. BUSINESS

Overview

The Partnership is a Delaware limited partnership formed on September 19, 2013 to become a diversified Partnership serving energy companies throughout North America. We currently provide essential midstream services including independent pipeline inspection and integrity services to producers and pipeline companies and water and environmental services with SWD facilities to U.S. onshore oil and natural gas producers and trucking companies. On January 21, 2014, we completed the IPO of our limited partner common units. As part of the transaction, affiliates of Holdings conveyed an aggregate 50.1% interest in the TIR Entities in exchange for an aggregate 15.7% ownership in the Partnership. Affiliates of Holdings held the remaining 49.9% interest in the TIR Entities that was acquired by the Partnership effective February 1, 2015. As a result, the Partnership now owns 100% of the TIR Entities.

Our business is currently organized into three reportable segments: (1) Pipeline Inspection Services (“PIS”), which includes the TIR Entities, (2) Integrity Services (“IS”), comprised of Brown and (3) Water and Environmental Services (“W&ES”). We also have a number of other potential lines of business in our IRS private letter ruling (“PLR”) that would allow us to further diversify our business activities and lines of business serving the energy industry.

Through the PIS segment, we provide independent inspection services to various energy, public utility and pipeline companies in both the United States and Canada. Inspectors in this segment perform a variety of inspection services on both new and existing midstream pipelines, midstream assets and infrastructure, gathering systems, and distribution systems, including data gathering and supervision of third-party construction, inspection, and maintenance and repair projects. Results in this segment are driven primarily by the number and type of inspectors performing services for our customers and the fees they charge for those services, which depend on the nature and duration of the project. PIS is mainly comprised of the operations of the TIR Entities.

The IS segment primarily provides hydrostatic testing services to major natural gas and petroleum companies and pipeline construction companies of both newly-constructed and existing natural gas and petroleum pipelines. Field personnel in this segment perform various integrity services on newly-constructed and existing oil and natural gas pipelines. Results in this segment are driven primarily by the number and skill level of field personnel performing the integrity services, size and length of the pipelines tested, the complexity of services provided, the utilization of our equipment, and the nature and duration of the projects, typically based on fixed bid agreements with customers. The IS segment is mainly comprised of the operations of Brown.

W&ES provides SWD services to oil and natural gas producers and trucking companies and consists of the operations of CEP LLC, which owns and operates eight commercial SWD facilities in the Bakken Shale region of the Williston Basin in North Dakota and two in the Permian Basin in Texas. We generate revenue by treating produced water and flowback water and injecting the water into our SWD facilities. Results are driven primarily by the volume of water injected into our SWD facilities and the fees charged related to these services. These fees are charged on a per-barrel basis and vary based on the quantity and type of saltwater disposed, competitive dynamics, and operating costs. Our SWD facilities currently utilize specialized equipment and remote monitoring to minimize downtime and increase efficiency for peak utilization and are located in close proximity to existing producing wells and expected future drilling sites, making our SWD facilities attractive to our current and future customers. These facilities also contain oil skimming processes that remove oil from flowback and produced water that has been delivered to the sites. We then generate revenue by selling the residual oil recovered from the water treatment process. In addition to the ten SWD facilities owned by CEP LLC, our consolidated subsidiary, CES LLC, provides management and staffing services for an additional SWD facility in the Bakken Shale region, pursuant to a management agreement. CES LLC also owns a 25% interest in this facility. The W&ES segment is directly tied to oil and gas activity and is impacted by changes in commodity prices, competition and newly completed oil and gas wells.

Our Relationship with Cypress Energy Holdings, LLC

All of the equity interests in our general partner are owned by Holdings, which is owned by Charles C. Stephenson, Jr., various family trusts of Mr. Stephenson's family, a company controlled by our Chairman, Chief Executive Officer and President, Peter C. Boylan III, Henry Cornell and a company controlled by Mr. Cornell. Holdings' owners bring substantial industry relationships and specialized, value-creation capabilities that we believe continue to benefit us. Mr. Stephenson has over 50 years of experience as a leader in the oil and natural gas industry. He was the founder, Chairman and Chief Executive Officer of Vintage Petroleum prior to its sale to Occidental Petroleum in 2006 and is also the retired Chairman of Premier Natural Resources, a private oil and natural gas exploration and production company that he co-founded. Mr. Boylan has extensive executive management experience with public and private companies and also has extensive public company directorship experience. As the owners of our general partner and the direct or indirect owners of approximately 64.3% of our outstanding limited partner interests, Holdings and its affiliates have a strong alignment of interests with our minority unitholders to ensure the on-going successful execution of our business plan.

Business Strategies

Our principal business objective is to build a diversified Partnership serving energy customers that will allow us, over time, to incrementally increase the quarterly cash distributions that we pay to our unitholders. We expect to achieve this objective through the following business strategies:

Capitalize on improving industry fundamentals.

PIS. We intend to continue to position ourselves as a trusted provider of high quality essential inspection services, as we believe the pipeline inspection services market offers attractive long-term growth fundamentals. Over the last few years, new laws have been enacted in the U.S. that, in the future, will require operators to undertake more frequent and more extensive inspections of their pipeline assets. These requirements are independent and not tied to the current state of the oil and gas industry as a whole. Additionally, a significant portion of the pipeline infrastructure in North America was installed decades ago and is therefore more susceptible to failure and requires more frequent inspections. We believe that increasingly stringent U.S. federal and state laws and regulations and aging pipeline infrastructures will result in increased need for inspection and integrity services and higher demand for independent, third-party inspectors capable of navigating these complicated requirements. The current energy downturn has impacted our customers. However, most of our clients are investment–grade, well-capitalized companies that have long lead time projects requiring our services in addition to the ongoing maintenance and integrity work on their aging pipelines. Our business is not immune to the industry downturn, however, we believe that we can continue to grow organically by acquiring new customers and additional work from existing customers. In 2016, we added 23 new customers in this segment. We also continue to grow our business development team to pursue these opportunities.

IS. Effective May 1, 2015, we acquired Brown, which represents our Integrity Services business segment. The two year industry downturn materially impacted Brown and the IS segment. We took a variety of actions in the second half of 2016 to materially reduce the cost structure of Brown. We remain cautiously optimistic that Brown is well positioned to resume its growth as customers have become more active following the industry downturn over the last two years, as is evidenced by the addition of 18 new customers in 2016. It is our intent to capitalize on the strong reputation of Brown and assist in expanding the geography of our IS business.

W&ES. We believe that the water and environmental services market will continue to offer long-term growth fundamentals and we intend to maintain our position as a high quality operator of SWD facilities, despite the recent downturn in the oil and gas industry as a whole that has materially impacted this segment over the last two years. We took aggressive actions in the second quarter of 2016 to adjust our cost structure to the lower volumes associated with the industry downturn. We continue to look for pipeline opportunities with E&P companies that will secure water for our SWD facilities. Regulations continue to increase and we have proven to our customers that we are a trusted and dependable service provider. Increasingly, E&P companies are having their central procurement and Environment, Health and Safety ("EHS") conduct inspections of our SWD facilities. This trend should benefit our Partnership. We remain an approved vendor for many prestigious investment grade E&P companies that demand very high standards from their vendors. Although the oil and gas industry can be cyclical in nature (as is evidenced by the two year downturn), our current business strategy is to derive a material portion of our volume and revenue from existing wells. Although new drilling activity declined materially the last two years, the rebound in commodity prices have led to an increase in drilling activity in both basins in which we operate. Currently, the Permian is much stronger than the Bakken. A portion of W&ES SWD facilities will continue to suffer declines in volumes and pricing until the market rebounds leading to additional drilling and completions that, in turn, generate new produced water for the life of those newly completed oil and gas wells. We intend to capitalize on the continued demand for removal, treatment, storage and disposal of flowback and produced water by positioning ourselves as a trusted, dependable provider of safe, high-quality water and environmental services to our energy customers.

Optimize existing SWD assets. The average age of our SWD facilities was 4.3 years at the end of 2016. We estimate that we only utilized approximately 25% of the aggregate annual capacity of these facilities for the year ended December 31, 2016 as a result of the two year industry downturn. Our permitted capacity is much higher than our estimated capacity of approximately 50 million barrels per year. We are seeking to increase the utilization of our existing SWD facilities by attracting new volumes from existing customers and by developing new customer relationships, including pipelines. In 2012, only one pipeline was directly connected to our SWD facilities. Today we have nine pipelines connected to five of our SWD facilities. Because many of the costs of constructing and operating an SWD facility are either upfront capital costs or fixed costs, we expect that increased utilization of our existing SWD facilities over time will lead to increased gross margin and operating cash flow in W&ES. The two-year industry downturn placed material pressure on both the volumes we processed and the prices we were able to charge for our services. The industry began a recovery following OPEC's decision to reduce production in November 2016.

Increase the number of pipelines connected to our SWD facilities. As more oil and natural gas producers focus on improving operational safety and reducing liability, carbon footprint, road damage, and the total transportation cost associated with trucking saltwater, we anticipate that they will increasingly prefer to utilize pipeline systems to transport their saltwater directly to SWD facilities. We intend to purchase or construct, whether alone or in joint ventures, saltwater pipeline systems that connect producers to our SWD facilities or newly developed SWD facilities. We continue to focus on increasing pipeline water delivered to our facilities. Our 2016 pipeline water volumes increased 82,000 barrels from piped water volumes in 2015. As a percentage of total water volume, pipeline water was 45% in 2016 and was 31% of total water volume in 2015. We will continue to focus on these potential pipeline opportunities.

Leverage customer relationships in our business segments. We intend to pursue new strategic development opportunities with oil and natural gas producing customers that increase the utilization of our assets and lead to cross-selling opportunities between our business segments. Many customers of W&ES also own gathering systems, storage facilities, gas plants, compression stations, and other pipeline assets to which we can offer pipeline inspection and integrity services. In North Dakota, new inspection rules have been proposed in the legislature that may benefit PIS and IS. In addition, we intend to enhance our relationships with our customers in PIS by broadening the services we provide, including expanding our ultrasonic nondestructive examination services. By cross-selling our service offerings and adding complementary service offerings, we believe that we can further integrate into our customers' operations and increase our profitability and distributable cash flow.

Pursue strategic, accretive acquisitions. We intend to pursue accretive acquisitions that will complement the Partnership. Our business segments operate in industries that are fragmented, giving us the opportunity to make strategic and accretive acquisitions. We exercised discipline throughout 2015 and 2016 and avoided overpaying for acquisitions. We remain optimistic that attractive acquisition opportunities are currently present or will present themselves in the near future. We plan to expand W&ES by seeking water and solid acquisition opportunities in existing and additional high-growth resource plays throughout the U.S. that will diversify our customer base with a particular focus on pipeline opportunities directly with E&P customers. In addition, provided certain opportunities fit with our strategic plan of expanding our business (such as the addition of our IS segment), we intend to grow PIS and IS by acquiring other strategic pipeline service companies that will allow us to broaden the suite of services we offer our existing customer base. We expanded our PIS ownership in February 2015 by acquiring the remaining 49.9% of the TIR Entities not previously owned by the Partnership.

Our Business Segments

Our business is currently operated in three reportable segments: (1) Pipeline Inspection Services ("PIS"), which includes the TIR Entities, (2) Integrity Services ("IS"), comprised of Brown and (3) Water and Environmental Services ("W&ES"). Our IRS private letter ruling ("PLR") allows for expansion into other lines of business. Our long-term goal continues to be diversifying the Partnership into other attractive lines of business including, but not limited to, traditional midstream activities, production chemicals and remote monitoring of energy infrastructure, in addition to the continued expansion of our segments. For information relating to revenues from external customers, operating income, and total assets for each segment, refer to "*Note 14 – Segment Disclosures*" of our Consolidated Financial Statements included in "*Item 8. – Financial Statements and Supplementary Data*."

PIS

Overview. We believe that PIS is a leading provider of independent inspection services to the pipeline industry. We provide essential services for pipelines, gathering systems, local distribution systems, equipment, and facilities to our well established customer base. We provide inspection to oil and natural gas producers, public utility companies, and other pipeline operators that are required by law to inspect their gathering systems, storage facilities, infrastructure, distribution systems and pipelines. Our approximately 90 pipeline inspection and integrity customers include oil and natural gas producers, pipeline owners and operators and public utility companies throughout North America. We also have a joint venture with CF Inspection that is a nationally qualified minority owned inspection firm affiliated with one of CEH's owners. CF Inspection serves energy companies that require a minority owned vendor. We own 49% of CF Inspection and Cynthia A. Field, the daughter of Charles C. Stephenson, Jr. owns 51% of CF Inspection. In 2016, CF Inspection represented 4.6% of our consolidated revenue.

PIS offers independent inspection services for the following facilities and equipment:

- Transmission pipelines (oil, gas and liquids);
- Oil and natural gas gathering systems;
- Pump and compressor stations;
- Storage facilities and terminals; and
- Gas distribution systems.

Operations. Oil and natural gas producers, public utility companies, and other pipeline operators are required by federal and state law and regulation to inspect their pipelines and gathering systems on a regular basis in order to protect the environment and ensure the public safety. At the beginning of an engagement, our personnel meet with the customer to determine the scope of the project and related staffing needs. We then develop a customized, detailed staffing plan utilizing our proprietary database of more than 16,000 professionals. Our inspectors have significant industry experience and are certified to meet the qualification requirements of both the customer and the Pipeline and Hazardous Materials Safety Administration (“PHMSA”). As the industry continues to adopt new technology, demand has increased for inspectors with greater technical skills and computer proficiencies. Our customers require inspectors to undergo specific training prior to performing inspection work on their projects. We utilize the National Center for Construction Education and Research and Veriforce training curricula to train and evaluate employees, along with other resources. In addition to assignment-specific training, welding inspectors and coating inspectors also must meet special certification requirements. During the years ended December 31, 2016 and 2015, we employed or engaged an average of 1,147 and 1,392 inspectors, respectively, in the U.S. and Canada.

Our scope of services include the following:

- Project coordination (construction or maintenance coordination for in-line pipeline inspection projects);
- Staking services (marking a dig site for surveyed anomalies);
- Pig tracking services (mapping and tracking of third-party pipeline cleaning and inspection units, called pigs);

- Maintenance inspection (third-party pipeline periodic inspection to comply with PHMSA regulations);

- Construction inspection (third-party new construction inspection / oversight on behalf of owner);

- Ultrasonic nondestructive examination services (using high-frequency sound waves to detect pipeline imperfections); and

- Related data management services.

IS

Overview. The IS segment, comprised of Brown, provides hydrostatic testing and related services to the pipeline industry, including major natural gas and petroleum companies, as well as pipeline construction companies. We focus on helping our customers meet regulatory pipeline integrity requirements. The company's primary emphasis is on hydrostatic testing projects on new and existing pipelines required to maintain compliance with state and federal regulations. We perform all aspects of pipeline hydrostatic testing including filling, pressure testing, and dewatering. Unique test conditions, such as ultra-high pressure tests and pneumatic or nitrogen testing, are performed on a routine basis as well. We provide services on newly-constructed and existing natural gas and petroleum pipelines.

Operations. Oil and natural gas producers, midstream operators, public utility companies, and other pipeline operators are required by federal and state law to perform routine maintenance on their pipelines and gathering systems on a regular basis. In addition, operators and or pipeline construction companies are required to integrity-test newly-constructed pipelines prior to placing them in service. In the IS segment, we contract directly with pipeline owners or with pipeline construction companies to provide testing services. We own and operate our own fill and testing equipment, including specially-designed test trailers. We use a range of fill and pressure equipment to accommodate projects of various sizes. The segment averaged 23 and 33 field technicians performing the testing services during the years ended December 31, 2016 and 2015, respectively.

W&ES Segment

Overview. Through W&ES, which specializes in water and environmental services, we own and operate ten SWD facilities, eight of which are in the Bakken Shale region of the Williston Basin in North Dakota and two of which are in the Permian Basin in west Texas. Five of our facilities are connected to nine different pipelines owned by various energy companies in both North Dakota and the Permian basin. In addition to owning and operating the ten SWD facilities, we manage another SWD facility in which we own a 25% interest. W&ES is comprised of the operations of CEP LLC and its Predecessor.

Operations. W&ES currently generates revenue by providing the following services:

Flowback water management. We dispose of flowback water produced from hydraulic fracturing operations during the completion of oil and natural gas wells. Fracturing fluids, including a significant amount of water and proppant, are injected into the well during the completion process and are partially recovered as flowback water. When it is removed, this flowback water contains sand, salt, chemicals, and residual oil. The drilling and completion phase typically occurs during the first 30 to 90 days following commencement of production of the life of a well. The oil and natural gas producer typically either transports the flowback water to one of our SWD facilities via pipeline or by truck or contracts with a trucking company for transport. Once the water is received at the SWD facility, we treat the water through a combination of separation tanks, gun barrels, and chemical processes, store the water as necessary prior to injection, and then inject the water into the SWD well at depths of at least 4,000 feet after recovering the skim oil. Like produced water, we assess the composition of flowback water in our facilities so that we can maximize oil separation and treat the water to maximize the life of our equipment and the wellbore. We believe our approach to scientifically and methodically filtering and treating the flowback water prior to injecting it into our wells helps extend the life of our wells and furthers our reputation as an environmentally-conscious service provider.

Produced water management. We dispose of naturally-occurring water that is extracted during the oil and natural gas production process. This produced water is generated during the entire lifecycle of an oil and natural gas well. While the level of hydrocarbon production declines over the life of a well, the amount of saltwater produced may decline more slowly or, in some cases, may even increase over time. The oil and natural gas producer separates the produced water from the production stream and either transports it to one of our SWD facilities by truck or pipeline or contracts with a trucking company to transport it to one of our SWD facilities. Once we receive the water at one of our SWD facilities, we filter and treat the water and then inject it into the SWD well at depths of at least 4,000 feet after recovering any skim oil. We also maintain the ability to store saltwater pending injection. All of our existing facilities were constructed using completion techniques consistent with current industry practices. We periodically sample, test, and assess produced water to determine its chemistry so that we can properly treat the water with the appropriate chemicals that maximize oil separation and the life of the wells.

Byproduct sales. Before we inject flowback and/or produced water into an SWD well, we separate the residual oil from the saltwater stream. We then store the residual oil in our tanks and sell it to third parties. The residual oil recovery can be material when substantial drilling and completions occur nearby our SWD facilities.

Management of existing SWD facilities. In addition to the SWD facilities we own or lease, we own CES LLC, a management and development company that manages an additional SWD facility in North Dakota. Our responsibilities in managing an SWD facility typically include operations, billing, collections, insurance, maintenance, repairs and, in some cases, sales and marketing. We are compensated for management of this facility based on a percentage of the gross revenue of the facility or a minimum monthly fee.

The majority of our disposed saltwater volumes are derived from produced water that is generated throughout the life of the oil or natural gas well. For the years ended December 31, 2016, 2015 and 2014, produced water represented approximately 96%, 93%, and 82%, respectively, of our total barrels of disposed water. This differentiates us from many competitors that focus on flowback water and the associated skim oil revenue. As a region matures and the predominant activity shifts from drilling and completion of wells to production, our facilities continue to experience demand for ongoing processing of wastewater produced over the life of the wells.

Each of our SWD facilities are open 365 days per year. Our locations in North Dakota currently include onsite offices and sleeping quarters. In Texas, we have an office and housing at our Pecos, Texas facility. We supplement our operations with various automated technologies to improve their efficiency and safety. We have installed 24-hour digital video monitoring and recording systems at each facility. These systems allow us to track operations and unloading and to identify the customers at our facilities. We believe that our commitment to operating our facilities with sophisticated technology and automation contributes to our enhanced operating margins and provides our customers with increased safety and regulatory compliance. We anticipate that more of our SWD facilities will be run through technological automation with off-site monitoring and control. Our facilities have been inspected and approved by several of our public E&P customers that have stringent approval standards and field audits performed by their Environmental, Health and Safety groups.

The amount of saltwater disposed in our SWD facilities decreased 5.6 million barrels for the year ended December 31, 2016 to 13.3 million barrels as compared to the year ended December 31, 2015 due primarily to decreased oil and gas well activity in the Bakken region as well as increased competition in the Permian basin. The volume of saltwater decreased from 19.1 million barrels for the year ended December 31, 2014 to 18.9 million barrels for the year ended December 31, 2015, a decline of approximately 0.2 million barrels, driven primarily by substantially lower activity in the Bakken region. Several new facilities opened during 2016 in the Permian basin that competed for business with our locations.

As of December 31, 2016, we had an aggregate of approximately 115,000 barrels of maximum daily disposal capacity in the following SWD facilities, all of which were built using completion techniques consistent with current industry practices and utilizing well depths of at least 5,000 feet with injection intervals beginning at least 4,000 feet beneath the surface. Our permitted capacity is much higher.

Location	County	In-service Date	Leased / Owned (3)
Tioga, ND	Williams	June 2011	Owned
Manning, ND	Dunn	December 2011	Owned
Grassy Butte, ND	McKenzie	May 2012	Leased
New Town, ND (1)	Mountrail	June 2012	Leased
Pecos, TX (1)	Reeves	July 2012	Owned
Williston, ND	Williams	August 2012	Owned
Stanley, ND	Mountrail	September 2012	Owned
Orla, TX (1)	Reeves	September 2012	Owned
Belfield, ND	Billings	October 2012	Leased
Watford City, ND (1), (2)	McKenzie	May 2013	Leased
Arnegard, ND (1)	McKenzie	August 2014	Leased

(1) Currently receives piped water.

(2) We own a 25.0% non-controlling interest in this SWD facility.

(3) Some facilities are constructed on land that is leased under long-term arrangements.

Principal Customers

PIS

Customers of PIS are principally oil and natural gas producers, pipeline owners and operators, and public utility or local distribution companies with infrastructure in North America. During the years ended December 31, 2016 and

2015, PIS had 85 - 95 customers. The five largest customers in this segment generated approximately, 62%, and 65% of our segment revenue for the years ended December 31, 2016 and 2015, respectively. For the years ended December 31, 2016 and 2015, we had three customers that individually accounted for more than 10% of segment revenues.

IS

IS customers are primarily pipeline construction companies and, in some instances, the pipeline owners. During the period from May 1, 2015 (acquisition date) through December 31, 2015, we had 61 customers. During the year ended December 31, 2016, we had approximately 60 customers. Our ten largest customers generated approximately 71% of our total segment revenue during the year ended December 31, 2016. We had two customers that each generated more than 10% of the total segment revenues during 2016. Our ten largest customers generated approximately 70% of our revenue during the year ended December 31, 2015. We had two customers that each generated more than 10% of the total segment revenues during 2015.

W&ES

W&ES customers are oil and natural gas exploration and production companies, including majors and independents, trucking companies and third-party purchasers of residual oil operating in the regions that we serve. In the years ended December 31, 2016, 2015 and 2014, we had approximately 180, 178, and 206 customers, respectively, in W&ES. Our ten largest customers generated approximately 65%, 62%, and 60% of W&ES revenue for the years ended December 31, 2016, 2015, and 2014, respectively. For the years ended December 31, 2016 and 2015, there were two customers and one customer, respectively, that generated 10% or more of W&ES revenue.

Competition

PIS

The pipeline inspection business is highly competitive. PIS' competition consists primarily of three types of companies: independent energy inspection firms, engineering and construction firms, and diversified inspection service firms. Diversified inspection firms may inspect, for example, electric and nuclear facilities in addition to pipelines. We believe that the principal competitive factors in our business include gaining and maintaining customer approval to service their pipelines and gathering systems, the ability to recruit and retain qualified experienced inspectors with multiple skills and non-destructive examination experience, safety record, insurance, the level of inspector training provided, reputation, dependability of services, customer service and price.

IS

The pipeline integrity services business (hydrotesting) is highly competitive. We believe that the principal competitive factors in our business are customer service, safety and price. Our competition consists primarily of smaller regional integrity firms and pipeline construction companies that pipeline owners allow to test their own construction and repair work.

W&ES

The water and environmental services business is highly competitive with relatively low barriers of entry. During 2014, competitors opened a number of new locations around our existing facilities based upon anticipated new drilling activity prior to a downturn in the oil and gas industry beginning in November 2014. Our competition consists primarily of smaller regional companies that utilize a variety of disposal methods and generally serve specific geographical markets. In addition, we face competition from other large oil field service companies that also own trucking operations and our customers, who may have the option of using internal disposal methods instead of outsourcing to us or to another third-party disposal company. Many E&P companies also own their own SWD facilities and water gathering systems and therefore, do not send their produced water to third parties for disposal. We believe that the principal competitive factors in our businesses include gaining and maintaining customer approval of SWD facilities, location of facilities in relation to customer activity, reputation, safety record, reliability of service, track record of environmental & regulatory compliance, customer service, insurance coverage, and price.

Seasonality

PIS

Inspection work varies depending upon the geographic location of our customers. The third and beginning of the fourth quarters are historically the most active for our pipeline inspection services as our customers focus on completing projects by year-end. In addition, our Canadian customers use inspection services the most during the fourth and first quarters of the year when the tundra is frozen. We believe our presence across various regions in the U.S. and our presence in Canada helps mitigate the seasonality of our business. As we expand our relationships with public utility commissions in California and other locations with moderate climates, the seasonality of our inspection and integrity business could decline.

IS

Since most of the work of the IS segment is currently performed in the southern United States, weather does not create a seasonality issue. However, business has historically been slower in the first calendar quarter and during the month of November and December, presumably due to the holiday season and budgeting cycles of our customers.

W&ES

The overall operations and financial performance of our Bakken Shale operations are impacted by seasonality. The volume of saltwater that we handle in the Bakken Shale region of the Williston Basin in North Dakota tends to be lower in the winter, due to heavy snow and cold temperatures, and in the spring, due to heavy rains and muddy conditions that may lead to road restrictions and weight limits that can impact business. The amount of residual oil is also less prevalent and more difficult to separate from the saltwater during the winter months. Seasonality is not typically a significant factor in the Permian Basin in west Texas, however, ice and snow can lead to reduced activity for E&P companies operating in the region.

Regulation of the Industry

Environmental and Occupational Health and Safety Matters

Our operations and the operations of our customers are subject to numerous federal, state, and local environmental laws and regulations relating to worker health and safety, the discharge of materials, and environmental protection. These laws and regulations may, among other things, require the acquisition of permits for regulated activities; govern the amounts and types of substances that may be released into the environment in connection with our operations; restrict the way we handle or dispose of wastes; limit or prohibit our or our customers' activities in sensitive areas such as wetlands, wilderness areas, or areas inhabited by endangered or threatened species; require investigatory and remedial actions to mitigate pollution conditions caused by our current or former operations; and impose specific standards addressing worker protections. Numerous governmental agencies issue regulations to implement and enforce these laws, for which compliance is often costly and difficult. The violation of these laws and regulations may result in the denial or revocation of permits, issuance of corrective action orders, assessment of administrative and civil penalties and even criminal prosecution.

We do not anticipate that compliance with existing environmental and occupational health and safety laws and regulations will have a material effect on our Consolidated Financial Statements. However, these rules and regulations are constantly evolving, and amendments thereto could result in a material effect on our operations and financial position. Further, while we may occasionally receive citations from environmental regulatory agencies for minor violations, such citations occur in the ordinary course of our business and are not material to our operations. However, it is possible that substantial costs for compliance or penalties for non-compliance may be incurred in the future. It is also possible that other developments, such as the adoption of stricter environmental laws, regulations and enforcement policies, could result in additional costs or liabilities that we cannot currently quantify. Moreover, changes in environmental laws could limit our customers' businesses or encourage our customers to handle and dispose of oil and natural gas wastes in other ways, which, in either case, could reduce the demand for our services and adversely impact our business. For example, as a result of regulations issued in March 2014, all waste haulers transporting produced water in North Dakota must possess a valid permit for transporting solid waste from the North Dakota Department of Health to legally transport such waste. Texas already required the same.

The following is a summary of the more significant existing environmental and occupational health and safety laws and regulations to which our business operations and the operations of our customers are subject and for which compliance in the future may have a material adverse impact on our financial position, results of operations, or future cash flows.

Hazardous substances and wastes. Our operations are subject to environmental laws and regulations relating to the management and release of hazardous substances, solid wastes, hazardous wastes and petroleum hydrocarbons. These laws generally regulate the generation, storage, treatment, transportation and disposal of solid and hazardous waste and may impose strict joint and several liability for the investigation and remediation of affected areas where hazardous substances may have been released or disposed. For instance, the Comprehensive Environmental Response Compensation and Liability Act, or CERCLA, and comparable state laws impose 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. We may handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment. Under such laws, we could be required to remove previously disposed substances and wastes (including substances disposed of or released by prior owners or operators) or remediate contaminated property (including groundwater contamination, whether from prior owners or operators or other historical activities or spills). These laws may also require us to conduct natural resource damage assessments and pay penalties for such damages. It is not uncommon for neighboring landowners and other third-parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other pollutants into the environment. These laws and regulations may also expose us to liability for our acts that were in compliance with applicable laws at the time the acts were performed.

Petroleum hydrocarbons and other substances arising from oil and natural gas-related activities have been disposed of or released on or under many of our sites. At some of our facilities, we have conducted and continue to conduct monitoring or remediation of known soil and groundwater contamination. We will continue to perform such monitoring and remediation of known contamination, including any post remediation groundwater monitoring that may be required, until the appropriate regulatory standards have been achieved. These monitoring and remediation efforts are usually overseen by state environmental regulatory agencies. We estimate that we will incur costs of less than $0.1 million over the next one to three years in connection with continued monitoring and remediation of known contamination at our facilities.

In the future, we may also accept for disposal solids that are subject to the requirements of the federal Resource, Conservation and Recovery Act, or RCRA, and comparable state statutes. While RCRA regulates both solid and hazardous wastes, it imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. Most Exploration & Production ("E&P") waste is exempt from stringent regulation as a hazardous waste under RCRA. None of our facilities are currently permitted to accept hazardous wastes for disposal, and we take precautions to help ensure that hazardous wastes do not enter or are not disposed of at our facilities. Some wastes handled by us that currently are exempt from treatment as hazardous wastes may in the future be designated as "hazardous wastes" under RCRA or other applicable statutes. For example, in May 2016, a nonprofit environmental group filed suit in the federal district court for the District of Columbia, seeking a declaratory judgment directing the EPA to review and reconsider the RCRA E&P waste exemption. If the RCRA E&P waste exemption is repealed or modified, we could become subject to more rigorous and costly operating and disposal requirements.

We are required to obtain permits for the disposal of E&P waste as part of our operations. These regulations vary widely from state to state. State permits can restrict pressure, size and location of disposal operations, impose limits on the types and amount of waste a facility may receive and the overall capacity of a waste disposal facility. States may add additional restrictions on the operations of a disposal facility when a permit is renewed or amended. As these regulations change, our permit requirements could become more stringent and may require material expenditures at our facilities or impose significant restraints or financial assurances on our operations.

In the course of our operations, some of our equipment may be exposed to naturally occurring radiation associated with oil and natural gas deposits, and this exposure may result in the generation of wastes containing naturally occurring radioactive materials, or NORM. NORM wastes exhibiting trace levels of naturally occurring radiation in excess of established state standards are subject to special handling and disposal requirements, and any storage vessels, piping and work area affected by NORM may be subject to remediation or restoration requirements. It is possible that we may incur costs or liabilities associated with elevated levels of NORM.

Safe Drinking Water Act. Our underground injection operations are subject to the Safe Drinking Water Act, or SDWA, as well as analogous state laws and regulations. Under the SDWA, the EPA established the Underground Injection Control, or UIC, program, which established the minimum program requirements for state and local programs regulating underground injection activities. The UIC program includes requirements for permitting, testing, monitoring, record keeping and reporting of injection well activities, as well as a prohibition against the migration of fluid containing any contaminant into underground sources of drinking water. State regulations require us to obtain a permit from the applicable regulatory agencies to operate our underground injection wells. Any leakage from the subsurface portions of the injection wells could cause degradation of fresh groundwater resources, potentially resulting in suspension of our UIC permit, issuance of fines and penalties from governmental agencies, incurrence of expenditures for remediation of the affected resource and imposition of liability by third parties for property damages and personal injuries. In addition, storage of residual crude oil collected as part of the saltwater injection process prior to sale could impose liability on us in the event that the entity to which the oil was transferred fails to manage and, as necessary, dispose of residual crude oil in accordance with applicable environmental and occupational health and safety laws.

Our customers are subject to these same regulations. While these largely result in their needing our services, some waste regulations could have the opposite effect. For instance, some states, including Texas, have considered laws mandating the recycling of flowback and produced water. If such laws are passed, our customers may divert some saltwater to recycling operations that may have otherwise been disposed of at our facilities.

Oil Pollution Act of 1990. The Oil Pollution Act of 1990, or OPA, as amended, establishes strict liability for owners and operators of facilities that are the site of a release of oil into regulated waters. The OPA also imposes ongoing requirements on owners or operators of facilities that handle certain quantities of oil, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill. We handle oil at many of our facilities, and if a release of oil into the regulated waters occurred at one of our facilities, we could be liable for cleanup costs and damages under the OPA.

Water discharges. The federal Water Pollution Control Act, referred to as the Clean Water Act, and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into regulated waters and impose requirements affecting our ability to conduct activities in regulated waters and wetlands. Pursuant to the Clean Water Act and analogous state laws, permits must be obtained to discharge pollutants into regulated waters, and permits or coverage under general permits must also be obtained to authorize discharges of storm water runoff from certain types of industrial facilities, including many of our facilities. The Clean Water Act 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. Spill prevention, control and countermeasure requirements of federal laws require appropriate containment berms and similar structures to help prevent the contamination of regulated waters in the event of a hydrocarbon storage tank spill, rupture or leak. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

We believe that compliance with existing permits and regulatory requirements under the Clean Water Act and state counterparts will not have a material adverse effect on our business. Future changes to permits or regulatory requirements under the Clean Water Act, however, could adversely affect our business.

Endangered species. The federal Endangered Species Act, or ESA, restricts activities that may affect endangered or threatened species or their habitats. Many states also have analogous laws designed to protect endangered or threatened species.

For example, the lesser-prairie chicken was listed as threatened in March 2014, although a district court recently vacated this decision. Additionally, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the Fish and Wildlife Service is required to make a determination on the listing of more than 250 species as endangered or threatened under the ESA by the end of the Fish and Wildlife Service's 2017 fiscal year.

Although current listings have not had a material impact on our operations, the designation of previously unidentified endangered or threatened species under the ESA or similar state laws could limit our ability to expand our operations and facilities or could force us to incur material additional costs. Moreover, listing such species under the ESA or similar state laws could indirectly, but materially, affect our business by imposing constraints on our customers' operations, including the curtailment of new drilling or a refusal to allow a new pipeline to be constructed.

Air emissions. Some of our operations also result in emissions of regulated air pollutants. The Clean Air Act, or CAA, and analogous state laws require permits for and impose other restrictions on facilities that have the potential to emit substances into the atmosphere above certain specified quantities or in a manner that could adversely affect environmental quality. Failure to obtain a permit or to comply with permit requirements could result in the imposition of substantial administrative, civil and even criminal penalties. We do not believe that any of our operations are subject to CAA permitting or regulatory requirements for major sources of air emissions, but some of our facilities could be subject to state "minor source" air permitting requirements and other state regulatory requirements for air emissions. Our IS segment has certain equipment requirements in various states.

Our customers' operations may be subject to existing and future CAA permitting and regulatory requirements that could have a material effect on their operations. The EPA recently approved and proposed new CAA rules requiring additional emissions controls and practices for oil and natural gas production wells, including wells that are the subject of hydraulic fracturing operations. The rules also establish new emission requirements for compressors, controllers, dehydrators, storage tanks, natural gas processing and certain other equipment used in the hydraulic fracturing process. These rules may increase the costs to our customers of developing and producing hydrocarbons, and as a result, may have an indirect and adverse effect on the amount of oilfield waste delivered to our facilities by our customers.

Climate change. The EPA has adopted regulations under existing provisions of the federal Clean Air Act, that, for example, require certain large stationary sources to obtain Prevention of Significant Deterioration, or PSD, pre-construction permits and Title V operating permits for GHG emissions. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States, including, among others, certain onshore oil and natural gas processing and fractionating facilities, which was expanded in October 2015 to include onshore petroleum and natural gas gathering and boosting activities and natural gas transmission pipelines. Additionally, the U.S. Congress has in the past considered adopting legislation to reduce emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap-and-trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants or major producers of fuels, such as refineries and natural gas processing plants, to acquire and surrender emission allowances that correspond to their annual emissions of GHGs. In addition, in December 2015, over 190 countries, including the United States, reached an agreement to reduce greenhouse gas emissions. The agreement entered into force in November 2016 after more than 70 countries, including the United States, ratified or otherwise consent to be bound by the agreement. The EPA and other federal and state agencies have also acted to address greenhouse gas emissions in other industries, most notably coal-fired power generation, and as a result could attempt in the future to impose additional regulations on the oil and natural gas industry.

Although it is not possible at this time to estimate how potential future laws or regulations addressing GHG emissions would impact our business, either directly or indirectly, any future federal or state laws or implementing regulations that may be adopted to address GHG emissions in areas where we operate could require us or our customers to incur increased operating costs. Regulation of GHGs could also result in a reduction in demand for and production of oil and natural gas, which would result in a decrease in demand for our services. We cannot predict with any certainty at this time how these possibilities may affect our operations, but effects could be materially adverse.

Hydraulic fracturing. We do not conduct hydraulic fracturing operations, but we do provide treatment and disposal services with respect to the fluids used and wastes generated by our customers in such operations, which are often necessary to drill and complete new wells and maintain existing wells. Hydraulic fracturing involves the injection of water, sand or other proppants and chemicals under pressure into target geological formations to fracture the surrounding rock and stimulate production. Presently, hydraulic fracturing is regulated primarily at the state level, typically by state oil and natural gas commissions and similar agencies. Several states, including Texas and North Dakota, where we conduct our water and environmental services business, have either adopted or proposed laws and/or regulations to require oil and natural gas operators to disclose chemical ingredients and water volumes used to hydraulically fracture wells, in addition to more stringent well construction and monitoring requirements. The chemical ingredient information is generally available to the public via online databases including fracfocus.org, and this may bring more public scrutiny to hydraulic fracturing operations.

At the federal level, the SDWA regulates the underground injection of substances through the UIC program and generally exempts hydraulic fracturing from the definition of “underground injection.” The U.S. Congress has in recent legislative sessions considered legislation to amend the SDWA, including legislation that would 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.

Federal agencies have also asserted regulatory authority over certain aspects of the process within their jurisdiction. For example, the EPA issued an Advanced Notice of Proposed Rulemaking seeking comment on its intent to develop regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing, and proposed effluent limitations for the disposal of wastewater from unconventional resources to publicly owned treatment works. In addition, the U.S. Department of the Interior (“DOI”) published a rule that updates existing regulation of hydraulic fracturing activities on federal lands, including requirements for disclosure, well bore integrity and handling of flowback water. This rule has been stayed pending the resolution of various legal challenges.

The EPA conducted a study of the potential impacts of hydraulic fracturing activities on drinking water. The EPA released its final report in December 2016. The study concluded that under certain limited circumstances, hydraulic fracturing activities and related disposal and fluid management activities, could adversely affect drinking water supplies. This study and other studies that may be undertaken by the EPA or other governmental authorities, depending on their results, could spur initiatives to regulate hydraulic fracturing under the SDWA or otherwise. If new federal, state or local laws or regulations that significantly restrict hydraulic fracturing are adopted, such legal requirements could result in delays, eliminate certain drilling and injection activities and make it more difficult or costly for our customers to perform fracturing. Any such regulations limiting or prohibiting hydraulic fracturing could reduce oil and natural gas exploration and production activities by our customers and, therefore, adversely affect our business. Such laws or regulations could also materially increase our costs of compliance and doing business by more strictly regulating how hydraulic fracturing wastes are handled or disposed.

Occupational Safety and Health Act. We are subject to the requirements of the Occupational Safety and Health Act, or OSHA and comparable state laws that regulate the protection of employee health and safety. OSHA's hazard communications standard requires that information about hazardous materials used or produced in our operations be maintained and provided to employees, state and local government authorities and citizens. These laws and regulations are subject to frequent changes. Failure to comply with these laws could lead to the assertion of third-party claims against us, civil and/or criminal fines and changes in the way we operate our facilities that could have an adverse effect on our financial position.

Seismic activity. Several states have acted to address a growing concern that the underground injection of water into disposal wells has triggered seismic activity in certain areas. Some states, including Texas, have promulgated rules or guidance in response to these concerns. In Texas, the Texas Railroad Commission ("TRC") published a final rule in October 2014 governing permitting or re-permitting of disposal wells that will require, among other things, the submission of information on seismic events occurring within a specified radius of the disposal well location, as well as logs, geologic cross sections and structure maps relating to the disposal area in question. If the permittee or an applicant of a disposal well permit fails to demonstrate that the injected fluids are confined to the disposal zone or if scientific data indicates such a disposal well is likely to be or determined to be contributing to seismic activity, then the TRC may deny, modify, suspend or terminate the permit application or existing operating permit for that well. These new seismic permitting requirements applicable to disposal wells impose more stringent permitting requirements and are likely to result in added costs to comply or, perhaps, may require alternative methods of disposing of salt water and other fluids, which could delay production schedules and also result in increased costs. Additional regulatory measures designed to minimize or avoid damage to geologic formations may be imposed to address such concerns.

Employees

The Partnership does not have any employees. All of the employees that conduct our business are employed by affiliates of our general partner, but we sometimes refer to these individuals in this report as our employees. We are managed and operated by the directors and officers of our general partner. All of our executive management personnel are employees of CEM LLC or another affiliate of Holdings, and devote the portion of their time to our business and affairs that is required to manage and conduct our operations. As of December 31, 2016 and 2015, we employed approximately 95 and 105 people, respectively, in our executive and shared services area, who provide direct support for our operations, none of whom are covered by collective bargaining agreements. Under the terms of our amended and restated omnibus agreement, we reimburse CEM LLC for the provision of various general and administrative services incurred for our benefit, for direct expenses incurred by CEM LLC on our behalf and for expenses allocated to us as a result of our becoming a public entity. In addition, PIS does not have any employees. All of the employees that conduct the PIS business do so through CEM TIR, providing the necessary personnel resources to PIS. PIS employed or engaged approximately 1,300 and inspectors as of December 31, 2016 and 2015, of which approximately 320 and 160, respectively, were engaged in our Canadian operations. The number of employees in the PIS group vary month to month and project to project. The Tulsa headquarters group operates a shared services model that provides accounting, billing, treasury, human relations, information technology, and other services to all of our divisions. Most of our inspector employees are billable to clients and they work in the field on client assets and infrastructure including, but not limited to, pipelines. Our IS segment directly employed approximately 30 individuals at December 31, 2016, down from about 70 at December 31, 2015. The employees in IS are full-time employees that we pay even when they are not utilized and billable on hydrotesting work for customers.

There were approximately 10 people employed by CEM LLC at December 31, 2016 that worked at our Texas and North Dakota facilities. CEM LLC also owned CEM-Brown, which provided staff for our North Dakota SWD facility operations prior to 2016. Our total Texas and North Dakota staff was reduced approximately 70% in 2016 primarily due to additional automation at our facilities. CEM LLC and CEM-Brown have been reimbursed a management fee to compensate them for the cost of the Texas and North Dakota employees, benefits and various other services provided to us.

Insurance Matters

Our customers require that we maintain certain minimum levels of insurance and evaluate our insurance coverage as part of the initial and ongoing approval process they require to use our services to treat and dispose of their waste. We also carry a variety of insurance coverages for our operations as required by law. However, our insurance may not be sufficient to cover any particular loss or may not cover all losses, and losses not covered by insurance would increase our costs. Also, insurance rates have been subject to wide fluctuation, and changes in coverage could result in less coverage, increases in cost or higher deductibles and retentions. Also, insurance rates have been subject to wide fluctuation, and changes in coverage could result in less coverage, increases in cost or higher deductibles and retentions.

The SWD and the pipeline inspection and integrity businesses can be dangerous, involving unforeseen circumstances such as environmental damage from leaks, spills or vehicle accidents. To address the hazards inherent in W&ES, our insurance coverage includes business, auto liability, commercial general liability, employer's liability, environmental and pollution and other coverage. To address the hazards inherent in PIS and IS, insurance coverage includes employer's liability, auto liability, employee benefits liabilities, and contractor's pollution and other coverage. Coverage for environmental and pollution-related losses is subject to significant limitations and are commonly provided for exclusion on such policies. We do not carry business interruption insurance given its cost and coverage limitations.

Available Information

Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (the "Exchange Act") are made available free of charge on our website at www.cypressenergy.com as soon as reasonably practicable after these reports have been electronically filed with, or furnished to, the SEC. These documents are also available on the SEC's website at www.sec.gov, or a unitholder may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. No information from either the SEC's website or our website is incorporated herein by reference.

ITEM 1A. RISK FACTORS

Unitholders should consider carefully the following risk factors together with all of the other information included in this Annual Report on Form 10-K and our other reports filed with the SEC before investing in our common units. If any of the following risks were actually to occur, our business, financial condition or results of operations could be materially adversely affected. In that case, the trading price of our common units could decline and a unitholder could lose all or part of their investment.

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 cash reimbursement to our general partner and its affiliates to enable us to pay our minimum quarterly distributions to holders of our units.

In order to pay the minimum quarterly distribution of $0.3875 per unit per quarter, or $1.55 per unit on an annualized basis, we will require available cash of approximately $4.6 million per quarter, or $18.4 million per year, based on the number of outstanding common units as of March 8, 2017. We may not have sufficient available cash from operating surplus each quarter to enable us to pay the minimum quarterly distribution. Because of various factors, including the recent oil and gas economic downturn, it is currently anticipated that, for the immediate future, our quarterly distributions may be significantly less than our minimum quarterly distribution (potentially half the current distribution). On February 14, 2017, we officially exited subordination pursuant to the terms of the Partnership agreement. As a result, our subordinated units were converted to common units at that time. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the fees we charge, and the margins we realize, from PIS, IS and W&ES;
- the number and types of projects conducted by PIS and IS and the volume of saltwater handled in W&ES;
- the amount of residual oil we are able to separate and sell from the saltwater we receive that can be impacted by the quality and price of the oil;
- the cost of achieving organic growth in current and new markets;
- our ability to make profitable acquisitions of pipeline inspection and integrity companies, other SWD facilities, and other types of businesses;
- the level of competition from other companies;
- governmental regulations, including changes in governmental regulations, in our industry;
- prevailing economic and market conditions, including low or volatile commodity prices and their effect on our customers; and

weather and natural disasters, lightning, seismic activity, vandalism and acts of terror.

In addition, the actual amount of cash we will have available for distribution will depend on other factors, some of which are beyond our control, including:

- the level of capital expenditures we make;
- the cost of acquisitions;
- the level of our operating costs and expenses and the performance of our various facilities, inspectors and staff;
- our debt service requirements, interest rates, and other liabilities;
- fluctuations in our working capital needs;
- our ability to borrow funds and access capital markets;
- restrictions contained in our debt agreements;
- the amount of cash reserves established by our general partner; and
- other business risks affecting our cash levels.

We serve customers who are involved in drilling for, producing and transporting oil and natural gas. Adverse developments affecting the oil and natural gas industry or drilling activity, including sustained low or further reduced oil or natural gas liquids prices, reduced demand for oil and natural gas products, adverse weather conditions, and increased regulation of drilling and production, could have a material adverse effect on our results of operations.

W&ES depends on our oil and natural gas customers' willingness to make operating and capital expenditures to develop and produce oil and natural gas in the United States. A reduction in drilling activity generally results in decreases in the volumes of new flowback and produced water generated, which adversely impacts our revenues. Therefore, if these expenditures decline, our business is likely to be adversely affected.

The level of activity in the oil and natural gas exploration and production industry in the U.S. has been volatile. According to the Baker Hughes oil and gas drilling rig count, the U.S. weekly aggregate rig count reached an all-time high of 4,530 rigs in December 1981 and a post-1942 low of 488 rigs in April 1999. From January 2010 through February 2015, the aggregate U.S. weekly rig count has remained above 1,220 rigs, reaching a peak of 2,026 rigs in November 2011 and declining to 404 rigs in May 2016. The prices of crude oil and related products has dropped substantially in the fourth quarter of 2014 and have been negatively affected by a combination of factors, including weakening demand, increased worldwide production, the decision by the Organization of Petroleum Exporting Countries to keep production levels unchanged and a strengthening in the U.S. dollar relative to most other currencies. Further downward pressure on commodity prices continued throughout 2015 and 2016. If crude oil prices do not rise, or take longer to recover than anticipated, exploration and production companies, pipeline owners and operators and public utility or local distribution companies in the regions we conduct our business may reduce capital spending on maintaining their pipelines or oil and natural gas production. W&ES constitutes approximately 3%, 4% and 6% of our revenue for the years ended December 31, 2016, 2015 and 2014, respectively. The Bakken region of North Dakota generally requires higher oil prices than are required in the Permian Basin in order to generate suitable economic returns for E&P companies. Therefore, a continued decrease in drilling activity or hydraulic fracking could have an adverse effect on our financial position, results of operations, demand for services, cash flows or our ability to make cash distributions to our unitholders or required payments on our outstanding debt.

Our customers' willingness to engage in drilling and production of oil and natural gas depends largely upon prevailing industry conditions that are influenced by numerous factors over which our management has no control, such as:

- the supply of and demand for oil and natural gas;
- the level of prices, and expectations about future prices, of oil and natural gas;
- the cost of exploring for, developing, producing and delivering oil and natural gas, including fracturing services;
- the expected rate of decline of current oil and natural gas production;
- the discovery rates of new oil and natural gas reserves;
- available pipeline and other transportation capacity;
- lead times associated with acquiring equipment and products and availability of personnel;
- weather conditions, including hurricanes, tornadoes, earthquakes, wildfires, drought or man-made disasters that can affect oil and natural gas operations over a wide area, as well as local weather conditions such as unusually cold winters in the Bakken Shale region of the Williston Basin in North Dakota that can have a significant impact on drilling activity in that region;
- domestic and worldwide economic conditions;
- contractions in the credit market;
- political instability in certain oil and natural gas producing countries;
- the continued threat of terrorism and the impact of military and other action, including military action in the Middle East or other parts of the world;
- governmental regulations, including income tax laws or government incentive programs relating to the oil and natural gas industry and the policies of governments regarding the exploration for and production and development

of their oil and natural gas reserves;

the level of oil production by non-OPEC countries and the available excess production capacity within OPEC;

oil refining capacity and shifts in end-customer preferences toward fuel efficiency;

potential acceleration in the development, and the price and availability, of alternative fuels;

the availability of water resources for use in hydraulic fracturing operations;

public pressure on, and legislative and regulatory interest in, federal, state, and local governments to ban, stop, significantly limit or regulate hydraulic fracturing operations;

technical advances affecting energy consumption;

access to necessary labor and services;

the access to and cost of debt and equity capital for oil and natural gas producers;

merger and divestiture activity among oil and natural gas producers; and

the impact of changing regulations and environmental and safety rules and policies.

The working capital needs of the PIS segment are substantial, which will reduce our borrowing capacity for other purposes and reduce our cash available for distribution.

PIS has substantial working capital needs throughout the year as we pay the majority of our inspectors on a weekly basis, but typically receive payment from our customers 45 to 90 days after the services have been performed. We intend to make borrowings under our credit facility to fund the working capital needs of PIS, and these borrowings will reduce the amount of credit available for other uses, such as working capital for our water disposal business, acquisitions and growth projects, and increase interest expense, thereby reducing cash available for distribution to our unitholders. Any cash generated from operations used to fund working capital needs will also reduce cash available for distribution to our unitholders. Additionally, if we experience any delays in payment by our pipeline inspection and integrity services customers, we may be subject to significant and rapid increases in our working capital needs that could require us to make further borrowings under our revolving credit facility or impact our ability to pay our minimum quarterly distributions.

18

We do not enter into long-term contracts with our customers, which subjects us to renewal or termination risks.

We do not typically enter into long-term contracts with customers. While we frequently operate under master services agreements with customers that set forth the terms on which we will provide services, customers operating under these agreements typically have the ability to terminate their relationship with us at any time at their sole discretion by choosing to not use us to provide pipeline inspection and integrity management services or by ceasing to deliver saltwater to our SWD facilities. Therefore, there is a heightened risk that our customers may decide not to use our inspection and integrity services or dispose of their saltwater through us. The failure of customers to continue to use our services could adversely affect our operations, financial condition, cash flows and ability to make cash distribution to our unitholders.

We depend on a limited number of customers for a substantial portion of our revenues. The loss of, or a material nonpayment by, our key customers could adversely affect our results of operations, financial condition and ability to make cash distributions to our unitholders.

Our ten largest customers generated approximately 80%, 71% and 78% of our consolidated revenue for the years ended December 31, 2016, 2015 and 2014, respectively. There were three customers that accounted for more than 10% of revenues for the years ended December 31, 2016, 2015 and 2014; Enbridge Energy Partners, Pacific Gas and Electric Company, and Plains All America Pipeline in 2016; Enbridge Energy Partners, Enterprise Products Partners and Plains All America Pipeline in 2015 and 2014. Revenues from these customers resulted from inspection operations, which are activities conducted by our PIS segment. The loss of all, or even a portion of, the revenues from these customers, as a result of competition, market conditions or otherwise, could have a material adverse effect on our business, results of operations, financial condition and cash flows.

Our business is dependent upon the willingness of our customers to outsource their pipeline inspection and integrity service activities and waste management activities.

Our business is largely dependent on the willingness of customers to outsource their pipeline inspection and integrity service activities and the treatment of their water and environmental services. Some pipeline owners and operators currently inspect and perform integrity activities on their own pipeline systems using the same techniques and technologies that we use, as well as others that we currently do not employ. In addition, many oil and natural gas producing companies own and operate waste treatment, recovery and SWD facilities, and some producers recycle saltwater on-site. Most oilfield operators, including many of our customers, have numerous abandoned wells that could be licensed for use in the disposition of internally generated waste and third-party waste in competition with us. Additionally, technologies may be developed that could be used by our customers to recycle saltwater and to recover oil through oilfield waste processing. Our current customers could decide to inspect and perform integrity activities on their own pipeline systems or process and dispose of their waste internally, either of which could have a material adverse effect on our financial position, results of operations, cash flows and our ability to make cash distributions to our unitholders.

Our markets are highly competitive, and competition could adversely impact our financial position, results of operations, demand for services, cash flows or our ability to make required payments on debt outstanding.

We have many competitors in PIS, IS and W&ES. Other companies offer similar pipeline inspection and integrity services or third-party saltwater disposal in our primary markets. Some of our customers also compete with us in the treatment and disposal sector by offering such services to other oil and natural gas companies. Our customers regularly evaluate the best combination of value and price from competing alternatives and new technologies and can move between alternatives or, in some cases, develop their own alternatives with relative ease. This competition influences the prices we charge and requires us to control our costs aggressively and maximize efficiency in order to maintain acceptable operating margins; however, we may be unable to do so and remain competitive on a cost-for-service basis. In addition, existing and future competitors may develop or offer services or new technologies that have pricing, location or other advantages over the services we provide, including a lower cost of capital

The credit risks of our concentrated customer base could result in losses.

Many of our customers are oil and natural gas companies that have or may face liquidity constraints in light of the current commodity price environment. This concentration of our customers in the energy industry may impact our overall exposure to credit risk as customers may be similarly affected by prolonged changes in economic and industry conditions. If a significant number of our customers experience a prolonged business decline or disruptions, we may incur increased exposure to credit risk and bad debts.

Disruptions in the transportation services of trucking companies transporting saltwater could adversely affect our results of operations and cash available for distribution to our unitholders.

We primarily depend on trucking companies to transport saltwater to our SWD facilities. In recent years, certain states, including North Dakota and Texas, and counties have increased enforcement of weight limits on trucks used to transport raw materials on their public roads. Also, as a result of regulations issued in March 2014, all waste haulers transporting produced water in North Dakota must possess a valid permit for transporting solid waste from the North Dakota Department of Health to legally transport such wastes. It is possible that the states, counties and cities in which W&ES conducts its operations may modify their laws to further reduce truck weight limits, or impose curfews or other restrictions on the use of roadways. Such legislation and enforcement efforts could result in delays in transporting saltwater to our SWD facilities and increased costs to transport saltwater to our facilities, which may either increase our operating costs or reduce the amount of saltwater transported to our SWD facilities. This could decrease our operating margins or amounts of saltwater disposed at our SWD facilities and thereby affect our results of operations and cash available for distribution.

A significant increase in fuel or insurance prices may adversely affect the transportation costs of our trucking company customers, which could result in a decrease in the rates for our saltwater and environmental services they would be willing to pay.

Fuel is a significant operating expense for our trucking customers, and a significant increase in fuel prices will result in increased transportation costs to them. The price and supply of fuel is unpredictable and fluctuates based on events such as geopolitical developments, supply and demand for oil and natural gas, actions by oil and natural gas producers, war and unrest in oil producing countries and regions, regional production patterns and weather concerns. A significant increase in fuel prices could drive down the prices our trucking company customers would be willing to pay, which would reduce our revenues and impact our ability to make distributions to our unitholders. Insurance is a significant operating expense for our trucking customers, and a significant increase in insurance prices or decrease in availability of coverage results in increased transportation costs to them.

Volumes of residual oil recovered during the saltwater water treatment process can vary. Any significant reduction in residual oil content in the water we treat, or the price we achieve for residual oil sales, will affect our recovery of residual oil and, therefore, our profitability.

Approximately 6%, 8% and 22% of our revenue for the years ended December 31, 2016, 2015 and 2014, respectively, in W&ES was derived from sales of residual oil recovered during the saltwater treatment process. Our ability to recover sufficient volumes of residual oil is dependent upon the residual oil content in the saltwater we treat, which is, among other things, a function of water type, chemistry, source and temperature. Generally, where outside temperatures are lower, there is less residual oil content and separation is more difficult. Thus, our residual oil recovery during the winter season is lower than our recovery during the summer season in North Dakota.

Additionally, residual oil content will decrease if, among other things, producers begin recovering higher levels of residual oil in saltwater prior to delivering such saltwater to us for treatment. Also, the revenues we derive from sales of residual oil are subjected to fluctuations in the price of oil. Any reduction in residual crude oil content in the saltwater we treat or the prices we realize on our sales of residual oil could materially and adversely affect our profitability.

Our business may be difficult to evaluate because we have a limited period of historical financial and operating data.

Prior to June 26, 2013, our historical financial and operating data does not include PIS. Prior to May 1, 2015, our historical financial and operation data does not include IS. As a result, we have provided only limited financial and operating data regarding the consolidated business that we operate. The historical financial and operating results of our business may be materially different from our future financial and operating results. Our future results will depend on our ability to efficiently manage our integrated operations and execute our business strategy. Our historical financial performance should not be considered reliable indicators of our future performance.

In addition, we face challenges and uncertainties in financial and operational planning as a result of the limited access to historical data regarding volumes of oilfield waste treated and related sales and pricing. Our first facilities were opened during 2011, and other companies in the SWD industry do not regularly release historical data related to their SWD facilities. This limited data may make it more difficult for us and our investors to evaluate our business and prospects and to forecast our future operating results.

We are vulnerable to the potential difficulties, expenses and uncertainties associated with rapid growth and expansion.

We grew rapidly since our inception in 2012 prior to the industry downturn, primarily through acquisitions. We believe that our future success depends on our ability to manage growth and the demands from increased responsibility on our management personnel. The following factors could present difficulties to us:

- organizational challenges common to large, expansive operations;
- administrative burdens;
- employee insurance;

- limitations with systems and technology;
- safety and training;
- ability to recruit, train and retain personnel and managers;
- ability to obtain permits for expanded operations;
- access to debt and equity capital on attractive terms; and
- long lead times associated with acquiring equipment and building any new facilities.

Our operating results could be adversely affected if we do not successfully manage these potential difficulties.

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

We will distribute substantially all of our available cash after expenses and prudent operating reserves to our unitholders. We expect that we will rely primarily upon external financing sources, including borrowings under our credit facilities and the issuance of debt and equity securities, to fund growth capital expenditures. However, we may not be able to obtain equity or debt financing on terms favorable to us, or at all. To the extent we are unable to efficiently finance growth externally, our cash distribution policy will significantly impair our ability to grow. In addition, because we distribute all of our available cash, we may not grow as quickly as businesses that reinvest their available cash to expand ongoing operations. Furthermore, Holdings is under no obligation to fund our growth. To the extent we issue additional units in connection with the financing of other growth capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per-unit distribution level. There are no limitations in our partnership agreement on our ability to issue additional units, including units ranking senior to the common units. The incurrence of borrowings or other debt by us to finance our growth strategy would result in interest expense, which in turn would affect the available cash that we have to distribute to our unitholders.

Our utilization of existing capacity, expansion of existing SWD facilities and construction or purchase of new SWD facilities may not result in revenue increases and will be subject to regulatory, environmental, political, legal and economic risks, which could adversely affect our operations and financial condition.

A portion of our strategy to grow and increase distributions to unitholders is dependent on our ability to utilize available capacity at our existing facilities, expand existing SWD facilities and construct or purchase new SWD facilities. The construction of a new SWD facility or the extension, renovation or expansion of an existing SWD facility, such as by connecting the SWD facility to pipeline systems, involves numerous business, competitive, regulatory, environmental, political and legal uncertainties, most of which are beyond our control. If we undertake these projects, they may not be completed on schedule or at all or at the budgeted cost. Furthermore, we will not receive any material increases in revenues until after completion of the project, although we will have to pay financing and construction costs during the construction period. As a result, new SWD facilities may not be able to attract enough demand for water and environmental services to achieve our expected investment return, which could materially adversely affect our results of operations and financial condition and our ability in the future to make distributions to our unitholders.

Our ability to acquire assets from Holdings or third parties is subject to risks and uncertainty. If we are unable to make acquisitions on economically acceptable terms, our future growth would be limited, and any acquisitions we may make may reduce, rather than increase, our cash flows and ability to make distributions to unitholders. Furthermore, we may not realize the benefits from or successfully integrate any acquisitions.

A portion of our strategy to grow our business and increase distributions to unitholders is dependent on our ability to make acquisitions that result in an increase in cash we generate on a per unit basis. The acquisition component of our strategy is based, in large part, both on our expectation of continuing consolidation in the industries in which we operate and our ability to acquire interests in additional assets from Holdings.

Holdings is seeking acquisitions of other types of businesses that may be suitable to our operations in the future. We may have the opportunity to make acquisitions directly from Holdings and its affiliates in the future. The consummation and timing of any future acquisitions of these assets will depend upon, among other things, Holdings' and its affiliates' willingness to offer these assets for sale, our ability to negotiate acceptable purchase agreements and commercial agreements with respect to the assets and our ability to obtain financing on acceptable terms. We can offer no assurance that we will be able to successfully consummate any future acquisitions with Holdings and its affiliates, and Holdings and its affiliates are under no obligation to accept any offer that we may choose to make. In addition, certain of these assets may require substantial capital expenditures in order to maintain compliance with applicable regulatory requirements or otherwise make them suitable for our commercial needs. For these or a variety of other reasons, we may decide not to acquire these assets from Holdings and its affiliates if, and when, Holdings and its affiliates offers such assets for sale, and our decision will not be subject to unitholder approval.

Additionally, we may not be able to make accretive acquisitions from third parties if we are:

- unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts;
- unable to obtain financing for these acquisitions on economically acceptable terms;
- outbid by competitors; or
- for any other reason.

If we are unable to make acquisitions from Holdings and its affiliates or third parties, our future growth and ability to increase distributions will be limited. Furthermore, even if we do consummate acquisitions that we believe will be accretive, they may in fact result in a decrease in cash flow.

Any acquisition involves potential risks, including, among other things:

- mistaken assumptions about disposal capacity, number and quality of inspectors, revenues and costs, cash flows, capital expenditures and synergies;
- the assumption of unknown liabilities;
- limitations on rights to indemnity from the seller;
- mistaken assumptions about the overall costs of equity or debt;
- the diversion of management’s attention from other business concerns;
- integrating business operations or unforeseen regulatory issues;
- unforeseen new regulations;

- unforeseen difficulties operating in new geographic areas; and

- customer or key personnel losses at the acquired businesses.

If we consummate any future acquisitions, our capitalization and results of operations may change significantly, and unitholders will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

We conduct a portion of our operations through entities that we partially own, which subjects us to additional risks that could have a material adverse effect on our financial condition and results of operations.

We own a 51.0% interest in Brown Integrity, LLC, a 25% interest in Alati Arnegard, LLC, and a 49.0% interest in CF Inspection Management, LLC. We may also enter into other arrangements with third parties in the future. Other third parties in future arrangements may have, obligations that are important to the success of the arrangement, such as the obligation to pay their share of capital and other costs of these partially owned entities. The performance of these third-party obligations, including the ability of our current partners to satisfy their respective obligations, is outside our control. If these parties do not satisfy their obligations under the arrangements, our business may be adversely affected.

Our joint venture arrangements may involve risks not otherwise present without a partner, including, for example:

- our partner shares certain blocking rights over transactions;

- our partner may take actions contrary to our instructions or requests or contrary to our policies or objectives;

- although we may control these joint ventures, we may have contractual duties to the joint ventures' respective other owners, which may conflict with our interests and the interests of our unitholders; and

- disputes between us and other partners may result in delays, litigation or operational impasses.

The risks described above or any failure to continue joint ventures or to resolve disagreements with our third-party partners could adversely affect our ability to transact the business that is the subject of such business, which would, in turn, negatively affect our financial condition, results of operations and ability to distribute cash to our unitholders.

Restrictions in our Credit Agreement could adversely affect our business, financial condition, results of operations, ability to make cash distributions to our unitholders and the value of our units.

On December 24, 2013, we entered into a $120.0 million Credit Agreement, which we used to replace the TIR Entities' existing revolving credit facility and mezzanine facilities. On October 21, 2014, the Credit Agreement was amended to increase the aggregate availability under the Credit Agreement from $120.0 million to $200.0 million and extend its maturity date to December 24, 2018. Our Credit Agreement limits our ability to, among other things:

- incur or guarantee additional debt;
- make certain investments and acquisitions;
- incur certain liens or permit them to exist;
- alter our line of business;
- enter into certain types of transactions with affiliates;
- merge or consolidate with another company; and
- transfer, sell or otherwise dispose of assets.

The Credit Agreement also contains certain covenants requiring us to maintain certain financial ratios. Our ability to meet those financial ratios and tests can be affected by events beyond our control, and we cannot assure unitholders that it would meet those ratios and tests.

The provisions of our new and future credit agreements may affect our ability to obtain future financing and pursue attractive business opportunities and our flexibility in planning for, and reacting to, changes in business conditions.

For example, our funds available for operations, future business opportunities and cash distributions to unitholders may be reduced by that portion of our cash flow required to make interest payments on our debt. Our ability to service our debt may depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control. If our operating results are not sufficient to service any future indebtedness, we will be forced to take actions such as reducing distributions, reducing or delaying our business activities, acquisitions, investments or capital expenditures, selling assets or seeking additional equity capital. We cannot assure unitholders that we would be able to take any of these actions, that these actions would be successful and permit us to meet our scheduled debt service obligations or satisfy our capital requirements, or that these actions would be permitted under the terms of our Credit Agreement or future debt agreements. Our new and future debt documents restrict our ability to dispose of assets and use the proceeds from the disposition. We may not be able to consummate those dispositions or to obtain the proceeds which we could realize from them and these proceeds may not be adequate to meet any debt service obligations then due. In addition, a failure to comply with the provisions of our new or future credit facilities could result in a default or an event of default that could enable its lenders to declare the outstanding principal of that debt, together with accrued and unpaid interest, to be immediately due and payable. If the payment of debt is accelerated, defaults under its other debt instruments, if any, may be triggered, and our assets may be insufficient to repay such debt in full, and the holders of our units could experience a partial or total loss of their investment in us. Please read *"Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources"* for additional information about our credit facilities.

Our existing and future debt levels may limit our flexibility to obtain financing and to pursue other business opportunities.

As of December 31, 2016, we had $136.9 million of indebtedness outstanding under our Credit Agreement. We will have the ability to incur additional debt, subject to limitations in our Credit Agreement. Our degree of leverage could have important consequences to us, including the following:

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

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

Our business could be adversely impacted if we are unable to obtain or maintain the regulatory permits required to develop and operate our facilities and to dispose of certain types of waste.

We own and operate SWD facilities in North Dakota and Texas, each with its own regulatory program for addressing the handling, treatment, recycling and disposal of saltwater. We are also required to comply with federal laws and regulations governing our operations. These environmental laws and regulations require that we, among other things, obtain permits and authorizations prior to the development and operation of waste treatment and storage facilities and in connection with the disposal and transportation of certain types of waste. The applicable regulatory agencies strictly monitor waste handling and disposal practices at all of our facilities. For many of our sites, we are required under applicable laws, regulations, and/or permits to conduct periodic monitoring, company-directed testing and third-party testing. Any failure to comply with such laws, regulations, or permits may result in suspension or revocation of necessary permits and authorizations, civil or criminal liability and imposition of fines and penalties, which could adversely impact our operations and revenues and ability to continue to provide oilfield water and environmental services to our customers.

In addition, we may experience a delay in obtaining, be unable to obtain, or suffer the revocation of required permits or regulatory authorizations, which may cause us to be unable to serve customers, interrupt our operations and limit our growth and revenue. Regulatory agencies may impose more stringent or burdensome restrictions or obligations on our operations when we seek to renew or amend our permits. For example, permit conditions may limit the amount or types of waste we can accept, pressures, require us to make material expenditures to upgrade our facilities, implement more burdensome and expensive monitoring or sampling programs, or increase the amount of financial assurance that we provide to cover future facility closure costs. Moreover, nongovernmental organizations or the public may elect to protest the issuance or renewal of our permits on the basis of developmental, environmental or aesthetic considerations, which protests may contribute to a delay or denial in the issuance or reissuance of such permits. It is not uncommon for local property owners or, in some cases oil and natural gas producers, to oppose SWD permits. Any such limitations or requirements could limit the water and environmental services we provide to our customers, or make such services more expensive to provide, which could have a material adverse effect on our financial position, results of operations, cash flows and our ability to make cash distributions to our unitholders.

Delays in obtaining permits by our customers for their operations could impair our business.

In most states, our customers are required to obtain permits from one or more governmental agencies in order to perform drilling and completion activities and to operate pipeline and gathering systems. Such permits are typically issued by state agencies, but federal and local governmental permits may also be required. The requirements for such permits vary depending on the location where such drilling and completion, and pipeline and gathering, activities will be conducted. As with all governmental permitting processes, there is a degree of uncertainty as to whether a permit will be granted, the time it will take for a permit to be issued, and the conditions that may be imposed in connection with the granting of the permit. Recently, moratoriums on the issuance of permits for certain types of drilling and completion activities have been imposed in some areas, such as New York. Some of our customers' drilling and completion activities may also take place on federal land or Native American lands, requiring leases and other approvals from the federal government or Native American tribes to conduct such drilling and completion activities. In some cases, federal agencies have cancelled proposed leases for federal lands and refused or delayed required approvals. Consequently, our customers' operations in certain areas of the U.S. may be interrupted or suspended for varying lengths of time, causing a loss of revenue to us and adversely affecting our results of operations in support of those customers.

In the future we may face increased obligations relating to the closing of our SWD facilities and may be required to provide an increased level of financial assurance to guaranty the appropriate closure activities occur for an SWD facility.

Obtaining a permit to own or operate an SWD facility generally requires us to establish performance bonds, letters of credit or other forms of financial assurance to address clean up and closure obligations at our SWD facilities. In particular, the regulatory agencies of the two states in which we operate require us to post letters of credit in connection with the operation of our SWD facilities. As we acquire additional SWD facilities or expand our existing SWD facilities, these obligations will increase. Additionally, in the future, regulatory agencies may require us to increase the amount of our closure bonds at existing SWD facilities. We have accrued approximately $139 thousand on our balance sheet related to our future closure obligations of our SWD facilities as of December 31, 2016. However, actual costs could exceed our current expectations, as a result of, among other things, federal, state or local government regulatory action, increased costs charged by service providers that assist in closing SWD facilities and additional environmental remediation requirements. Increased regulatory requirements regarding our existing or future SWD facilities, including the requirement to pay increased closure and post-closure costs or to establish increased financial assurance for such activities could substantially increase our operating costs and cause our available cash that we have to distribute to our unitholders to decline.

Changes in laws or government regulations regarding hydraulic fracturing could increase our customers' costs of doing business, limit the areas in which our customers can operate and reduce oil and natural gas production by our customers, which could adversely impact our business.

We do not conduct hydraulic fracturing operations, but we do provide treatment and disposal services with respect to the fluids used and wastes generated by our customers in such operations, which are often necessary to drill and complete new wells and maintain existing wells. Hydraulic fracturing involves the injection of water, sand or other proppants and chemicals under pressure into target geological formations to fracture the surrounding rock and stimulate production. Presently, hydraulic fracturing is regulated primarily at the state level, typically by state oil and natural gas commissions and similar agencies. Several states, including Texas and North Dakota, where we conduct our water and environmental services business, have either adopted or proposed laws and/or regulations to require oil and natural gas operators to disclose chemical ingredients and water volumes used to hydraulically fracture wells, in addition to more stringent well construction and monitoring requirements. The chemical ingredient information is generally available to the public via online databases including fracfocus.org, and this may bring more public scrutiny to hydraulic fracturing operations.

At the federal level, the SDWA regulates the underground injection of substances through the UIC program and generally exempts hydraulic fracturing from the definition of "underground injection." The U.S. Congress has in recent legislative sessions considered legislation to amend the SDWA including legislation that would 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.

Federal agencies have also asserted regulatory authority over certain aspects of the process within their jurisdiction. For example, the EPA issued an Advanced Notice of Proposed Rulemaking seeking comment on its intent to develop regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing, and proposed effluent limitations for the disposal of wastewater from unconventional resources to publicly owned treatment works. In addition, the U.S. Department of the Interior ("DOI") published a rule that updates existing regulation of hydraulic fracturing activities on federal lands, including requirements for disclosure, well bore integrity and handling of flowback water. This rule has been stayed pending the resolution of various legal challenges.

The EPA conducted a study of the potential impacts of hydraulic fracturing activities on drinking water. The EPA released its final report in December 2016. The study concluded that under certain limited circumstances, hydraulic fracturing activities and related disposal and fluid management activities, could adversely affect drinking water supplies. As part of this study, the EPA requested that certain companies provide them with information concerning the chemicals used in the hydraulic fracturing process. This study and other studies that may be undertaken by the EPA or other governmental authorities, depending on their results, could spur initiatives to regulate hydraulic fracturing under the SDWA or otherwise. If new federal, state or local laws or regulations that significantly restrict hydraulic fracturing are adopted, such legal requirements could result in delays, eliminate certain drilling and injection activities and make it more difficult or costly for our customers to perform fracturing. Any such regulations limiting or prohibiting hydraulic fracturing could reduce oil and natural gas exploration and production activities by our customers and, therefore, adversely affect our business. Such laws or regulations could also materially increase our costs of compliance and doing business by more strictly regulating how hydraulic fracturing wastes are handled or disposed.

Oil and natural gas producers' operations, especially those using hydraulic fracturing, are substantially dependent on the availability of water. Restrictions on the ability to obtain water may incentivize water recycling efforts by oil and natural gas producers which would decrease the volume of saltwater delivered to our SWD facilities.

Water is an essential component of oil and natural gas production during the drilling, and in particular, hydraulic fracturing, process. However, the availability of suitable water supplies may be limited for oil and natural gas producers due to reasons such as prolonged drought. As a result, some local water districts have begun restricting the use of water subject to their jurisdiction for hydraulic fracturing to protect local water supplies. In response to continuing drought conditions in 2015, 2014 and 2013, the Texas Legislature considered a number of bills that would have mandated recycling of flowback and produced water and/or prohibits recyclable water from being disposed of in wells. If oil and natural gas producers in Texas are unable to obtain water to use in their operations from local sources, they may be incentivized to recycle and reuse saltwater instead of delivering such saltwater to our Texas SWD facilities (or in other states that adopt similar programs). Similarly, mandatory recycling programs could reduce the amount of materials sent to us for treatment and disposal. Any such limits or mandates could adversely affect our business and results of operations.

Increased attention to seismic activity associated with hydraulic fracturing and underground disposal could result in additional regulations and adversely impact demand for our services.

There exists a growing concern that the underground injection of produced water into disposal wells has triggered seismic activity in certain areas. Some states, including Texas, have promulgated rules or guidance in response to these concerns. In Texas, the Texas Railroad Commission ("TRC") published a final rule in October 2014 governing permitting or re-permitting of disposal wells that will require, among other things, the submission of information on seismic events occurring within a specified radius of the disposal well location, as well as logs, geologic cross sections and structure maps relating to the disposal area in question. If the permittee or an applicant of a disposal well permit fails to demonstrate that the injected fluids are confined to the disposal zone or if scientific data indicates such a disposal well is likely to be or determined to be contributing to seismic activity, then the TRC may deny, modify, suspend or terminate the permit application or existing operating permit for that well. These new seismic permitting requirements applicable to disposal wells impose more stringent permitting requirements and are likely to result in added costs to comply or, perhaps, may require alternative methods of disposing of salt water and other fluids, which could delay production schedules and also result in increased costs. Additional regulatory measures designed to minimize or avoid damage to geologic formations may be imposed to address such concerns.

We and our customers may incur significant liability under, or costs and expenditures to comply with, environmental regulations, which are complex and subject to frequent change.

Our and our customer's operations are subject to stringent federal, state, provincial and local laws and regulations relating to, among other things, protection of natural resources, wetlands, endangered species, the environment, waste management, waste disposal, and transportation of waste and other materials. These laws and regulations may impose numerous obligations that are applicable to our and our customer's operations, including the acquisition of permits to conduct regulated activities, the incurrence of capital or operating expenditures to limit or prevent releases of materials from our or our customers' operations, and the imposition of substantial liabilities and remedial obligations for pollution or contamination resulting from our and our customer's operations.

Compliance with this complex array of laws and regulations is difficult and may require us to make significant expenditures. A breach of such requirements may result in suspension or revocation of necessary licenses or authorizations, civil liability for, among other things, pollution damage and the imposition of material fines.

Our operations also pose risks of environmental liability due to leakage, migration, releases or spills from our operations to surface or subsurface soils, surface water or groundwater. Some environmental laws and regulations impose strict, joint and several liabilities in connection with releases of regulated substances into the environment. Therefore, in some situations we could be exposed to liability as a result of our conduct that was lawful at the time it occurred or the conduct of, or conditions caused by, third parties.

Laws protecting the environment generally have become more stringent over time. We expect this trend to continue, which could lead to material increases in our costs for future environmental compliance and remediation, and could adversely affect our operations by restricting the way in which we treat and dispose of exploration and production, or E&P, waste or our ability to expand our business.

In particular, the RCRA, which governs the disposal of solid and hazardous waste, currently exempts certain E&P wastes from classification as hazardous wastes. In recent years, proposals have been made to rescind this exemption from RCRA. For example, in May 2016, a nonprofit environmental group filed suit in the federal district court for the District of Columbia, seeking a declaratory judgment directing the EPA to review and reconsider the RCRA E&P waste exemption. If the exemption covering E&P wastes is repealed or modified, or if the regulations interpreting the rules regarding the treatment or disposal of this type of waste were changed, our operations could face significantly more stringent regulations, permitting requirements, and other restrictions, which could have a material adverse effect on our business.

Under the terms of our amended and restated omnibus agreement, Holdings will indemnify us for certain potential claims, losses and expenses relating to environmental matters and associated with the operation of the assets contributed to us and occurring before the closing date of our IPO. However, the liability of Holdings for these indemnification obligations is subject to a $350,000 deductible. Moreover, our assets constitute a substantial portion of Holdings’ assets, and Holdings has not agreed to maintain any cash reserve to fund any indemnification obligations under our amended and restated omnibus agreement. In addition, changes in environmental laws occur frequently, and any such changes that result in more stringent and costly requirements would not be covered by the environmental indemnity and could have a material adverse effect on our operations or financial position.

We could incur significant costs in cleaning up contamination that occurs at our facilities.

Petroleum hydrocarbons, saltwater, and other substances and wastes arising from E&P related activities have been disposed of or released on or under many of our sites. At some of our facilities, we have conducted and may continue to conduct monitoring, and we will continue to perform such monitoring and remediation of known contamination until the appropriate regulatory standards have been achieved. These monitoring and remediation efforts are usually overseen by state environmental regulatory agencies. Costs for such remediation activities may exceed estimated costs, and there can be no assurance that the future costs will not be material. It is possible that we may identify additional contamination in the future, which could result in additional remediation obligations and expenses, which could be material.

We and our customers may be exposed to certain regulatory and financial risks related to climate change.

The EPA has adopted regulations under existing provisions of the federal Clean Air Act, that, for example, require certain large stationary sources to obtain Prevention of Significant Deterioration, or PSD, pre-construction permits and Title V operating permits for GHG emissions. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States, including, among others, certain onshore oil and natural gas processing and fractionating facilities, which was expanded in October 2015 to include onshore petroleum and natural gas gathering and boosting activities and natural gas transmission pipelines. Additionally, the U.S. Congress has in the past considered adopting legislation to reduce emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap-and-trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants or major producers of fuels, such as refineries and natural gas processing plants, to acquire and surrender emission allowances that correspond to their annual emissions of GHGs. In addition, in December 2015, over 190 countries, including the United States, reached an agreement to reduce greenhouse gas emissions. The agreement entered into force in November 2016 after over 70 countries, including the United States, ratified or otherwise consented to be bound by the agreement. The EPA and other federal and state agencies have also acted to address greenhouse gas emissions in other industries, most notably coal-fired power generation, and as a result could attempt in the future to impose additional regulations on the oil and natural gas industry.

Although it is not possible at this time to estimate how potential future laws or regulations addressing GHG emissions would impact our business, either directly or indirectly, any future federal or state laws or implementing regulations that may be adopted to address GHG emissions in areas where we operate could require us or our customers to incur increased operating costs. Regulation of GHGs could also result in a reduction in demand for and production of oil and natural gas, which would result in a decrease in demand for our services. We cannot predict with any certainty at this time how these possibilities may affect our operations, but effects could be materially adverse.

Finally, increasing concentrations of GHGs in the Earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events. If any such effects were to occur, they could adversely affect or delay demand for the oil or natural gas produced by our customers or otherwise cause us to incur significant costs in preparing for or responding to those effects.

Certain plant or animal species could be designated as endangered or threatened, which could limit our ability to expand some of our existing operations or limit our customers’ ability to develop new oil and natural gas wells.

The federal Endangered Species Act (“ESA”) restricts activities that may affect endangered or threatened species or their habitats. Many states also have analogous laws designed to protect endangered or threatened species. For example, the lesser-prairie chicken was listed as threatened in March 2014, although a district court recently vacated this decision.

Additionally, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the Fish and Wildlife Service is required to make a determination on the listing of more than 250 species as endangered or threatened under the ESA by the end of the Fish and Wildlife Service's 2017 fiscal year.

Although current listings have not had a material impact on our operations, the designation of previously unidentified endangered or threatened species under the ESA or similar state laws could limit our ability to expand our operations and facilities or could force us to incur material additional costs. Moreover, listing such species under the ESA or similar state laws could indirectly, but materially, affect our business by imposing constraints on our customers' operations, including the curtailment of new drilling or a refusal to allow a new pipeline to be constructed.

We have customers in New Mexico, Texas, Oklahoma, Wyoming and North Dakota that have operations within the habitat of the greater sage-grouse and the lesser prairie-chicken, and our own operations are strategically located in proximity to our customers. To the extent these species, or other species that live in the areas where our operations and our customers' operations are conducted, are listed under the ESA or similar state laws, this could limit our ability to expand our operations and facilities or could force us to incur material additional costs. Moreover, listing such species under the ESA or similar state laws could indirectly but materially affect our business by imposing constraints on our customers' operations.

We must comply with worker health and safety laws and regulations at our facilities and in connection with our operations, and failure to do so could result in significant liability and/or fines and penalties.

Our activities are subject to a wide range of national, state and local occupational health and safety laws and regulations. These environmental, health and safety laws and regulations applicable to our business and the business of our customers, including laws regulating the energy industry, and the interpretation or enforcement of these laws and regulations are constantly evolving. Failure to comply with these health and safety laws and regulations could lead to third-party claims, criminal and regulatory violations, civil fines and changes in the way we operate our facilities, which could increase the cost of operating our business and have a material adverse effect on our financial position, results of operations and cash flows and our ability to make cash distributions to our unitholders. Our safety and compliance record is also important to our clients, and our failure to maintain safe operations can materially impact our business.

A failure by our employees to follow applicable procedures and guidelines or on-site accidents could have a material adverse effect on our business.

We require our employees to comply with various internal procedures and guidelines, including an environmental management program and worker health and safety guidelines. The failure by our employees to comply with our internal environmental, health and safety guidelines could result in personal injuries, property damage or non-compliance with applicable governmental laws and regulations, which may lead to fines, remediation obligations or third-party claims. Any such fines, remediation obligations, third-party claims or losses could have a material adverse effect on our financial position, results of operations and cash flows. In addition, on-site accidents can result in injury or death to our or other contractors' employees or damage to our or other contractors' equipment and facilities and damage to other people, truck drivers, area residents and property. Any fines or third-party claims resulting from any such on-site accidents could have a material adverse effect on our business.

In addition, while an inspector is performing pipeline inspection or integrity services for us, the inspector is considered our employee and is eligible for workers' compensation claims if the inspector is injured or killed while working for us. As the inspectors generally travel to and from projects in their own vehicles, we may be responsible for workers compensation claims or third-party claims arising out of vehicle accidents, which could negatively affect our results of operations.

Unsatisfactory safety performance may negatively affect our customer relationships, workers compensation rates and, to the extent we fail to retain existing customers or attract new customers, adversely impact our revenues.

Our ability to retain existing customers and attract new business is dependent on many factors, including our ability to demonstrate that we can reliably and safely operate our business and stay current on constantly changing rules, regulations, training, and laws. Existing and potential customers consider the safety record of their service providers to be of high importance in their decision to engage third-party servicers. If one or more accidents were to occur at one of our operating sites, or pipelines or gathering systems we inspect, the affected customer may seek to terminate or cancel its use of our facilities or services and may be less likely to continue to use our services, which could cause us to lose substantial revenues. Further, our ability to attract new customers may be impaired if they elect not to purchase our third-party services because they view our safety record as unacceptable. In addition, it is possible that we will experience numerous or particularly severe accidents in the future, causing our safety record to deteriorate. This may be more likely as we continue to grow, if we experience high employee turnover or labor shortage, or add inexperienced personnel. In addition, we could be subject to liability for damages as a result of such accidents and could incur penalties or fines for violations of applicable safety laws and regulations.

Our business involves many hazards, operational risks and regulatory uncertainties, some of which may not be fully covered by insurance. If a significant accident or event occurs for which we are not adequately insured or if we fail to recover all anticipated insurance proceeds for significant accidents or events for which we are insured, our operations and financial results could be adversely affected.

Risks inherent to our industry, such as lightning strikes, equipment defects, vehicle accidents, explosions, earthquakes, and incidents related to the handling of fluids and wastes, can cause personal injury, loss of life, suspension of operations, damage to formations, damage to facilities, business interruption and damage to or destruction of property, equipment and the environment. We use fiberglass tanks at our SWD facilities because fiberglass is less corrosive than other materials traditionally utilized. These tanks are, however, more prone to lightning strikes than traditional tanks, as a result of fiberglass' tendency to store static electricity. The lightning protection systems we employ may not succeed in preventing lightning from damaging a facility. The risks associated with these types of accidents could expose us to substantial liability for personal injury, wrongful death, property damage, pollution and other environmental damages. The frequency and severity of such incidents will affect operating costs, insurability and relationships with employees and regulators.

Our insurance coverage may be inadequate to cover our liabilities. For instance, while our insurance policies apply to and cover costs imposed on us by retroactive changes in governmental regulations, the costs we incur as a result of such regulatory changes cannot be known in advance and may exceed our coverage limitations. In addition, we may not be able to maintain adequate insurance in the future at rates we consider reasonable and commercially justifiable and insurance may not continue to be available on terms as favorable as our current arrangements. The occurrence of a significant uninsured claim, a claim in excess of the insurance coverage limits maintained by us or a claim at a time when we are not able to obtain liability insurance could have a material adverse effect on our ability to conduct normal business operations and on our financial condition, results of operations and cash flows. In some cases, electrical storms can damage facility motors or electronics, and it may not be possible to prove to the insurance carrier that such storm caused the damage. We do not carry business interruption insurance on our SWD facilities and as a result, could suffer a significant loss in revenue that could impact our ability to pay distributions on our units.

Accidents or incidents related to the handling of hydraulic fracturing fluids, saltwater or other wastes are covered by our insurance against claims made for bodily injury, property damage or environmental damage and clean-up costs stemming from a sudden and accidental pollution event, provided that we report the event within 30 days after its commencement. The coverage applies to incidents the company is legally obligated to pay resulting from pollution conditions caused by covered operations. We may not have coverage if the operator is unaware of the pollution event and unable to report the "occurrence" to the insurance company within the required time frame. Although we have coverage for gradual, long-term pollution events at certain locations, this coverage does not extend to all places where we may be located or where we may do business. We also may have liability exposure if any pipelines or gathering systems transporting water to our SWD facilities develop a leak depending upon the terms of the contracts.

Due to our lack of asset and geographic diversification, adverse developments in the areas in which we are located could adversely impact our financial condition, results of operations and cash flows and reduce our ability to make

distributions to our unitholders.

Our SWD facilities are located exclusively in North Dakota and Texas. This concentration could disproportionately expose us to operational, economic and regulatory risk in these areas. Additionally, our SWD facilities currently comprise ten owned and one managed facility. Any operational, economic or regulatory issues at a single facility could have a material adverse impact on us. Due to the lack of diversification in our assets and the location of our assets, adverse developments in the our markets, including, for example, transportation constraints, adverse regulatory developments, or other adverse events at one of our SWD facilities, could have a significantly greater impact on our financial condition, results of operations and cash flows than if we were more diversified.

Changes in the provincial royalty rates and drilling incentive programs in Canada could decrease the oil and gas exploration and pipeline activities in Canada, which could adversely affect the demand for our pipeline inspection services.

Certain provincial governments collect royalties on the production from lands owned by the government of Canada. These fiscal royalty regimes are reviewed and adjusted from time to time by the respective provincial governments for appropriateness and competitiveness. Any increase in the royalty rates assessed by, or any decrease in the drilling incentive programs offered by, a provincial government could negatively affect the drilling activity and the need for pipelines and gathering systems, which could adversely affect the demand for our pipeline inspection services.

Conservation measures and technological advances could reduce demand for oil and natural gas.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy generation devices could reduce demand for oil and natural gas and our customers' drilling and production activities, and therefore the amount of drilling and production waste provided to us for treatment and disposal. Management cannot predict the impact of the changing demand for oil and natural gas services and products, and any major changes may have a material adverse effect on our business, financial condition, results of operations and cash flows.

New technology, including those involving recycling of saltwater or the replacement of water in fracturing fluid, may hurt our competitive position.

The saltwater disposal industry is subject to the introduction of new waste treatment and disposal techniques and services using new technologies including those involving recycling of saltwater, some of which may be subject to patent protection. As competitors and others use or develop new technologies or technologies comparable to ours in the future, we may lose market share or be placed at a competitive disadvantage. For example, some companies have successfully used propane as the fracturing fluid instead of water. Further, we may face competitive pressure to implement or acquire certain new technologies at a substantial cost. Some of our competitors may have greater financial, technical and personnel resources than we do, which may allow them to gain technological advantages or implement new technologies before we can. Additionally, we may be unable to implement new technologies or products at all, on a timely basis or at an acceptable cost. New technology could also make it easier for our customers to vertically integrate their operations or reduce the amount of waste produced in oil and natural gas drilling and production activities, thereby reducing or eliminating the need for third-party disposal. Limits on our ability to effectively use or implement new technologies may have a material adverse effect on our business, financial condition and results of operations.

Technology advancements in connection with alternatives to hydraulic fracturing could decrease the demand for our SWD facilities.

Some oil and natural gas producers are focusing on developing and utilizing non-water fracturing techniques, including those utilizing propane, carbon dioxide or nitrogen instead of water. If our producing customers begin to shift their fracturing techniques to waterless fracturing in the development of their wells, our saltwater disposal services could be materially impacted as these wells would not produce flowback water. In particular, our SWD facilities in west Texas could be negatively affected by these new technologies, as the drought conditions of west Texas make fracturing with materials other than water attractive alternatives.

We may be unable to ensure that customers will continue to utilize our services or facilities and pay rates that generate acceptable margins for us.

We cannot ensure that customers will continue to pay rates that generate acceptable margins for us. Our margins for W&ES could decrease if the volume of saltwater processed and disposed of by our customers' decreases or if we are unable to increase the rates charged to correspond with increasing costs of operations. Our revenues and profitability for PIS and IS could decrease if the demand for our inspectors decrease, if our safety record declines and we are unable to obtain affordable insurance, if we are unable to recruit and retain qualified inspectors or if we are unable to increase the daily and hourly rates charged to correspond with increasing costs of operations. In addition, new agreements for our services in these business segments entered into by us may not be obtainable on terms acceptable to us or, if obtained, may not be obtained on terms consistent with current practices, in which case our revenue and profitability could decline. We also cannot ensure that the parties from whom we lease, license or otherwise occupy the land on which certain of our facilities are situated, or the parties from whom we lease certain of our equipment, will renew our current leases, licenses or other occupancy agreements upon their expiration on commercially reasonable terms or at all. Any such failure to honor the terms of the leases or licenses or renew our current leases or licenses could have a material adverse effect on our financial position, results of operations and cash flows.

We may be unable to attract and retain a sufficient number of skilled and qualified workers.

The delivery of our water and environmental services and products requires personnel with specialized skills and experience who can perform physically demanding work. The saltwater disposal industry has experienced a high rate of employee turnover as a result of the volatility of the oilfield service industry and the demanding nature of the work, and workers may choose to pursue employment in fields that offer a less demanding work environment. In addition, PIS and IS are dependent on specialized inspectors, who must undergo specific training prior to performing inspection and integrity services.

Our ability to be productive and profitable will depend upon our ability to employ and retain skilled workers. In addition, our ability to expand our operations depends in part on our ability to increase the size of our skilled labor force. The demand for skilled workers is high, and the supply is limited. A significant increase in the wages paid by competing employers or the unionization of groups of our employees could result in a reduction of our skilled labor force, increases in the wage rates that we must pay, or both. Likewise, laws and regulations to which we are, or may in the future become, subject could increase our labor costs or subject us to liabilities to our employees. In addition, the U.S. customers in PIS and IS could choose to hire our inspectors directly. If any of these events were to occur, our capacity and profitability could be diminished and our growth potential could be impaired.

Our ability to operate our business effectively could be impaired if affiliates of our general partner fail to attract and retain key management personnel.

We depend on the continuing efforts of our executive officers and other key management personnel, all of whom are employees of affiliates of our general partner. Additionally, neither we, nor our subsidiaries, have employees. CEM LLC and its affiliates are responsible for providing the employees and other personnel necessary to conduct our operations. All of the employees that conduct our business are employed by affiliates of our general partner, including our Chairman, Chief Executive Officer and President, Peter C. Boylan III, and our Senior Vice President and Chief Financial Officer, G. Les Austin. The loss of any member of our management or other key employees could have a material adverse effect on our business. Consequently, our ability to operate our business and implement our strategies will depend on the continued ability of affiliates of our general partner to attract and retain highly skilled management personnel with industry experience. Competition for these persons is intense. Given our size, we may be at a disadvantage, relative to our larger competitors, in the competition for these personnel. We may not be able to continue to employ our senior executives and other key personnel or attract and retain qualified personnel in the future, and our failure to retain or attract our senior executives and other key personnel could have a material adverse effect on our ability to effectively operate our business.

Our business would be adversely affected if we or our customers experience significant interruptions.

We are dependent upon the uninterrupted operations of our SWD facilities for the processing of saltwater, as well as the operations of third-party facilities, such as our oil and natural gas producing customers, for uninterrupted demand of our water and environmental services. Any significant interruption at these facilities or inability to transport products to or from the third-party facilities to our SWD facilities for any reason would adversely affect our results of operations, cash flow and ability to make distributions to our unitholders. Operations at our facilities and at the facilities owned or operated by our customers could be partially or completely shut down, temporarily or permanently, as the result of any number of circumstances that are not within our control, such as:

- catastrophic events, including lightning strikes, hurricanes, seismic activity such as earthquakes, fires and floods;
- loss of electricity or power;
- explosion, breakage, loss of power, accidents to machinery, storage tanks or facilities;
- leaks in packers and tubing below the surface, failures in cement or casing or ruptures in the pipes, valves, fittings, hoses, pumps, tanks, containment systems or houses that lead to spills or employee injuries;

- environmental remediation;
- pressure issues that limit or restrict our ability to inject water into the disposal well or limitations with the injection zone formation and its permeability or porosity that could limit or prevent disposal of additional fluids;
- labor difficulties;
- malfunctions in automated control systems at the facilities;
- disruptions in the supply of saltwater to our facilities;
- failure of third-party pipelines, pumps, equipment or machinery; and
- governmental mandates, restrictions or rules and regulations.

In addition, there can be no assurance that we are adequately insured against such risks as the Partnership does not carry business interruption insurance, due to its relatively high cost as compared to its coverages and limitations thereof. As a result, our revenue and results of operations could be materially adversely affected.

The seasonal nature of the oilfield service industry in Canada may negatively affect us and our customers.

In Canada, the level of activity in the oilfield services industry is influenced by seasonal weather patterns. As warm weather returns in the spring, the winter's frost comes out of the ground (commonly referred to as "spring break up") rendering many secondary roads incapable of supporting heavy loads, and as a result, road bans are implemented prohibiting heavy loads from being transported in certain areas. As a result, the movement of the heavy equipment required for drilling and well servicing activities is restricted and the level of activity of our Canadian operations and the operations of our customers are consequently reduced.

The amount of cash we have available for distribution to holders of our common units depends primarily on our cash flow rather than on our profitability, which may prevent us from making distributions, even during periods in which we record net income.

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

Increases in interest rates could adversely impact our unit price, our ability to issue equity or incur debt for acquisitions or other purposes, and our ability to make cash distributions at our intended levels.

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

A failure in our operational and communications systems, loss of power, natural disasters, or cyber security attacks on any of our facilities, or those of third-parties, may adversely affect our results of operations and financial results.

Our business is dependent upon our operational systems to process a large amount of data and a substantial number of transactions. If any of our financial, operational or other data processing systems fail or have other significant shortcomings, our financial results could be adversely affected. Our financial results could also be adversely affected if an employee causes our operational or financial systems to fail, either as a result of inadvertent error or by deliberately tampering with or manipulating our operational systems. In addition, dependence upon automated systems may further increase the risk that operational system flaws, employee tampering or manipulation of those systems will result in losses that are difficult to detect.

Due to technology advances, we have become more reliant on technology to help increase efficiency in our business. We use computer programs to help run our financial and operations processes, and this may subject our business to increased risks. Any future cyber security attacks that affect our facilities, communications systems, our customers or any of our financial data could have a material adverse effect on our business. In addition, cyber-attacks on our customer and employee data may result in a financial loss and may negatively impact our reputation. We do not maintain specialized insurance for possible liability resulting from a cyber-attack on our assets that may shut down all or part of our business. Third-party systems on which we rely could also suffer operational system failure. Any of these occurrences could disrupt our business, result in potential liability or reputational damage or otherwise have an adverse effect on our financial results.

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 timely, reliable financial reports, prevent fraud and to operate successfully as a publicly traded partnership. Our efforts to develop and maintain our internal controls may not be successful, and we may be unable to maintain effective controls over our financial processes and reporting in the future or to comply with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002 ("Section 404"). For example, Section 404 requires us, among other things, to annually review and report on, and (except as described below) our independent registered public accounting firm to attest to, the effectiveness of our internal controls over financial reporting. 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, or 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 could subject us to regulatory scrutiny and a loss of confidence in our reported financial information, which could have an adverse effect on our business and would likely have a negative effect on the trading price of our common units.

We have recently implemented a new Enterprise Resource Planning ("ERP") business solution to create a system of integrated applications to manage our businesses and automate many functions related to financial reporting, human resources and other services. It is our intent through this ERP to integrate the major facets of our organization in order to improve planning, development, processes, sales, human resources management and other applications as they affect our evolving business model. Any failure(s) during this continued implementation process 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 a new ERP system implementation, we can provide no assurance as to our, or 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 could subject us to regulatory scrutiny and a loss of confidence in our reported financial information, which could have an adverse effect on our business and would likely have a negative effect on the trading price of our common units.

We are required to disclose changes made in our internal control over financial reporting on a quarterly basis, and we are required to assess the effectiveness of our controls annually. However, for as long as we are an “emerging growth company” under the Jumpstart Our Business Startups Act of 2012, or the JOBS Act, our independent registered public accounting firm will not be required to attest to the effectiveness of our internal controls over financial reporting pursuant to Section 404. We will need to be compliant by calendar year 2018, with an attest function performed by our independent registered public accounting firm for the year ended December 31, 2018. Even if we conclude that our internal controls over financial reporting are effective, our independent registered public accounting firm may issue a report that is qualified if it is not satisfied with our controls or the level at which our controls are documented, designed, operated or reviewed, or if it interprets the relevant requirements differently from us.

A sustained failure of our information technology systems could adversely affect our business.

An enterprise-wide information system has been developed and integrated into our operations. If our information technology systems are disrupted due to problems with the integration of our information system or otherwise, we may face difficulties in generating timely and accurate financial information. Such a disruption to our information technology systems could have an adverse effect on our financial condition, results of operations and cash available for distribution to our unitholders. In addition, we may not realize the benefits we anticipate from the implementation of our enterprise-wide information system.

We have recently implemented a new ERP business solution to create a system of integrated applications to manage our businesses and automate many functions related to financial reporting, human resources and other services. It is our intent through this ERP to integrate the major facets of our organization in order to improve planning, development, processes, sales, human resources management and other applications as they affect our evolving business model. We may not realize the benefits we anticipate should all or a part of the ERP implementation process prove to be ineffective.

Risks Inherent in an Investment in Us

Our general partner and its affiliates, including Holdings, have conflicts of interest with us and limited fiduciary duties to us and our unitholders, and they may favor their own interests to our detriment and that of our unitholders. Additionally, we have no control over the business decisions and operations of Holdings, and Holdings is under no obligation to adopt a business strategy that favors us.

As of the 2016 year-end, Holdings and its affiliates own a 64.3% limited partner interest in us and own and control our general partner and appoint all of the officers and directors of our general partner. Although our general partner has a duty to manage us in a manner that is in the best interests of our partnership and our unitholders, the directors and officers of our general partner also have a fiduciary duty to manage our general partner in a manner that is in the best interests of its owner, Holdings. Conflicts of interest may arise between Holdings and its affiliates, including our general partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of its affiliates, including Holdings, over the interests of our common unitholders. These conflicts include, among others, the following situations:

neither our partnership agreement nor any other agreement requires Holdings to pursue a business strategy that favors us or utilizes our assets, which could involve decisions by Holdings to invest in competitors, pursue and grow particular markets, or undertake acquisition opportunities for itself. Holdings' directors and officers have a fiduciary duty to make these decisions in the best interests of Holdings;

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

Holdings may be constrained by the terms of its debt instruments from taking actions, or refraining from taking actions, that may be in our best interests;

our partnership agreement replaces the fiduciary duties that would otherwise be owed by our general partner with contractual standards governing its duties, limiting our general partner's liabilities and restricting the remedies available to our unitholders for actions that, without such limitations, might constitute breaches of fiduciary duty;

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

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

expenditure, which would not reduce operating surplus, or a maintenance capital expenditure, which would reduce our operating surplus, and whether to set aside cash for future maintenance capital expenditures on certain of our assets that will need extensive repairs during their useful lives. This determination can affect the amount of available cash from operating surplus that is distributed to our unitholders and to our general partner, and the amount of adjusted operating surplus generated in any given period;

our general partner will determine which costs incurred by it are reimbursable by us;

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

our partnership agreement permits us to classify up to $10.0 million as operating surplus, even if it is generated from asset sales, non-working capital borrowings or other sources that would otherwise constitute capital surplus. This cash may be used to fund distributions to our general partner in respect of the general partner interest or the incentive distribution rights;

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

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

our general partner may exercise its right to call and purchase all of the common units not owned by it and its affiliates if it and its affiliates own more than 80.0% of the common units;

our general partner controls the enforcement of obligations owed to us by our general partner and its affiliates;

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

our general partner may or may not provide financial support to the Partnership. They may also require compensation for financial support in the form of additional units, preferred equity, dividend reinvestment plan, and other mechanisms; and

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

Under the terms of our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, does not apply to our general partner or any of its affiliates, including its executive officers, directors and owners. Any such person or entity that becomes aware of a potential transaction, agreement, arrangement or other matter that may be an opportunity for us will not have any duty to communicate or offer such opportunity to us. Any such person or entity will not be liable to us or to any limited partner for breach of any fiduciary duty or other duty by reason of the fact that such person or entity pursues or acquires such opportunity for itself, directs such opportunity to another person or entity or does not communicate such opportunity or information to us. This may create actual and potential conflicts of interest between us and affiliates of our general partner and result in less than favorable treatment of us and our unitholders. Please read *"Item 13 – Certain Relationships and Related Party Transactions – Conflicts of Interest and Duties,"*

Our partnership agreement requires that we distribute all of our available cash, which could limit our ability to grow and make acquisitions.

Our partnership agreement requires that we distribute all of our available cash to our unitholders. As a result, we expect to rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund our acquisitions and expansion capital expenditures. Therefore, to the extent we are unable to finance our growth externally, our cash distribution policy will significantly impair our ability to grow. In addition, because we will distribute all of our available cash, our growth may not be as fast as that of businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. There are no limitations in our partnership agreement, and we do not anticipate there being limitations in our indebtedness, on our ability to issue additional units, including units ranking senior to our common units as to distributions or in liquidation or that have special voting rights and other rights, and our unitholders will have no preemptive or other rights (solely as a result of their status as unitholders) to purchase any such additional units. The incurrence of additional commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which, in turn, may reduce the amount of cash that we have available to distribute to our unitholders.

Our general partner's discretion in establishing cash reserves may reduce the amount of cash we have available to distribute to unitholders.

Our partnership agreement requires our general partner to deduct from operating surplus the cash reserves that it determines are necessary to fund our future operating expenditures. In addition, the partnership agreement permits the general partner to reduce available cash by establishing cash reserves for the proper conduct of our business, to comply with applicable law or agreements to which we are a party, or to provide funds for future distributions to partners. These cash reserves will affect the amount of cash we have available to distribute to unitholders.

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

Our partnership agreement contains provisions that eliminate the fiduciary standards to which our general partner would otherwise be held by state fiduciary duty law and replaces those duties with several different contractual standards. For example, our partnership agreement permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner, free of any duties to us and our unitholders other than the implied contractual covenant of good faith and fair dealing. This provision entitles our general partner to consider only the interests and factors that it desires and relieves it of any duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates, or our limited partners. Examples of decisions that our general partner may make in its individual capacity include:

- how to allocate corporate opportunities among us and its affiliates;
- whether to exercise its limited call right;
- whether to seek approval of the resolution of a conflict of interest by the conflicts committee of the board of directors of our general partner;
- how to exercise its voting rights with respect to the units it owns;
- whether to elect to reset target distribution levels;
- whether to transfer the incentive distribution rights or any units it owns to a third party; and

whether or not to consent to any merger, consolidation or conversion of the partnership or amendment to the partnership agreement.

By purchasing a common unit, a unitholder is treated as having consented to the provisions in our partnership agreement, including the provisions discussed above. Please read *"Item 13 – Certain Relationships and Related Party Transactions – Conflicts of Interest and Duties."*

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

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

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

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

- provides that whenever our general partner makes a determination or takes, or declines to take, any other action in its capacity as our general partner, our general partner is required to make such determination, or take or decline to take such other action, in good faith, meaning that it subjectively believed that the determination or the decision to take or decline to take such action was in the best interests of our partnership, and will not be subject to any other or different standard imposed by our partnership agreement, Delaware law, or any other law, rule or regulation, or at equity;

- provides that our general partner will not have any liability to us or our unitholders for decisions made in its capacity as a general partner so long as it acted in good faith;

- provides that our general partner and its officers and directors will not be liable for monetary damages to us or our limited partners resulting from any act or omission unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our general partner or its officers and directors, as the case may be, acted in bad faith or engaged in intentional fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was unlawful; and

- provides that our general partner will not be in breach of its obligations under our partnership agreement or its fiduciary duties to us or our limited partners if a transaction with an affiliate or the resolution of a conflict of interest is approved in accordance with, or otherwise meets the standards set forth in, our partnership agreement.

In connection with a situation involving a transaction with an affiliate or a conflict of interest, our partnership agreement provides that any determination by our general partner must be made in good faith, and that our conflicts committee and the board of directors of our general partner are entitled to a presumption that they acted in good faith. In any proceeding brought by or on behalf of any limited partner or the partnership, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption. Please read *"Item 13 – Certain Relationships and Related Party Transactions – Conflicts of Interest and Duties."*

Cost reimbursements and fees due to Holdings for services provided to us or on our behalf following the termination of our amended and restated omnibus agreement could be substantial and will reduce our cash available for distribution to our unitholders.

Pursuant to our amended and restated omnibus agreement, prior to making any distributions to our unitholders, we will pay Holdings a quarterly administrative fee of $1.0 million for the provision of certain general and administrative expenses. However, during the year ended December 31, 2016, Holdings provided sponsor support to the Partnership by waiving payment of the quarterly administrative fee. Holdings received no consideration for this support. In the future, Holdings may require appropriate compensation if it provides any future additional support. This fee is subject to increase by an amount equal to the producer price index ("PPI") plus one percent or, with the concurrence of the conflicts committee, in the event of an expansion of our operations, including through acquisitions or internal growth. The amount of this fee is below the amount we would expect to reimburse the general partner for such services in the absence of the fee. In the event of termination of our amended and restated omnibus agreement, in lieu of the quarterly fee, we will be required by our partnership agreement to reimburse Holdings and its affiliates for all costs and expenses that they incur on our behalf for managing and controlling our business and operations, at which time we expect our payment for these services to increase. This increase may be substantial. Our partnership agreement provides that Holdings will determine in good faith the expenses that are allocable to us. Furthermore, Holdings and its affiliates will allocate other expenses related to our operations to us and may provide us other services for which we will be charged fees as determined by Holdings. Payments to Holdings and its affiliates following the termination of our amended and restated omnibus agreement could be substantial and will reduce the amount of cash we have available to distribute to unitholders.

Unitholders have very limited voting rights and, even if they are dissatisfied, they cannot remove our general partner without its consent.

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. For example, unlike holders of stock in a public corporation, unitholders will not have "say-on-pay" advisory voting rights. Unitholders did not elect our general partner or the board of directors of our general partner and will have no right to elect our general partner or the board of directors of our general partner on an annual or other continuing basis. The board of directors of our general partner is chosen by the member of our general partner, which is a wholly owned subsidiary of Holdings. Furthermore, if the unitholders are dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. As a result of these limitations, the price at which our common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

The unitholders will be unable initially to remove our general partner without its consent because our general partner and its affiliates own sufficient units to be able to prevent its removal. The vote of the holders of at least 66 2/3% of all outstanding common units is required to remove our general partner. As of March 8, 2017, Holdings and its affiliates own 64.3% of our outstanding common units.

Furthermore, unitholders' voting rights are further restricted by the partnership agreement provision providing that any units held by a person that owns 20.0% or more of any class of units then outstanding, other than our general partner, its affiliates, their transferees, and persons who acquired such units with the prior approval of the board of directors of our general partner, cannot vote on any matter.

Our partnership agreement also contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting the unitholders' ability to influence the manner or direction of management.

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

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, there is no restriction in our partnership agreement on the ability of Holdings to transfer its membership interest in our general partner to a third party. The new owner of our general partner would then be in a position to replace the board of directors and officers of our general partner with its own choices.

We may issue additional units without unitholder approval, which would dilute unitholders' existing ownership interests.

At any time, we may issue an unlimited number of general partner interests or limited partner interests of any type without the approval of our unitholders and our unitholders will have no preemptive or other rights (solely as a result of their status as unitholders) to purchase any such general partner interests or limited partner interests. Further, there are no limitations in our partnership agreement on our ability to issue equity securities that rank equal or senior to our common units as to distributions or in liquidation or that have special voting rights and other rights. The issuance by us of additional common units or other equity securities of equal or senior rank will have the following effects:

- our existing unitholders' proportionate ownership interest in us will decrease;
- the amount of cash we have available to distribute on each unit may decrease;
- the ratio of taxable income to distributions may increase;

- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of our common units may decline.

The issuance by us of additional general partner interests may have the following effects, among others, if such general partner interests are issued to a person who is not an affiliate of Holdings:

- management of our business may no longer reside solely with our current general partner; and
- affiliates of the newly admitted general partner may compete with us, and neither that general partner nor such affiliates will have any obligation to present business opportunities to us.

Holdings or its unitholders, directors or officers may sell units in the public or private markets, and such sales could have an adverse impact on the trading price of the common units.

As of March 8, 2017, Holdings and CEP-TIR together hold 6,957,349 common units. Additionally, we have agreed to provide Holdings and CEP-TIR with certain registration rights under applicable securities laws. The sale of these units in the public or private markets could have an adverse impact on the price of the common units or on any trading market that may develop.

Affiliates of our general partner, including, but not limited to, Holdings, may compete with us, and neither our general partner nor its affiliates have any obligation to present business opportunities to us.

Neither our partnership agreement nor our amended and restated omnibus agreement will prohibit Holdings or any other affiliates of our general partner from owning assets or engaging in businesses that compete directly or indirectly with us. Under the terms of our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, will not apply to our general partner or any of its affiliates, including Holdings. Any such entity that becomes aware of a potential transaction, agreement, arrangement or other matter that may be an opportunity for us will not have any duty to communicate or offer such opportunity to us. Moreover, except for the obligations set forth in our amended and restated omnibus agreement, neither Holdings nor any of its affiliates have a contractual obligation to offer us the opportunity to purchase additional assets from it, and we are unable to predict whether or when such an offer may be presented and acted upon. As a result, competition from Holdings and other affiliates of our general partner could materially and adversely impact our results of operations and distributable cash flow.

Our right of first offer on certain of Holdings' assets is subject to risks and uncertainty, and ultimately we may not acquire any of those assets.

Our amended and restated omnibus agreement provides us with a right of first offer on certain assets owned by and ownership interests held by Holdings and its subsidiaries that they decide to sell during the five-year period following the closing of our IPO. The consummation and timing of any acquisition by us of the assets covered by our right to first offer will depend upon, among other things, our ability to reach an agreement with Holdings on price and other terms and our ability to obtain financing on acceptable terms. Accordingly, we can provide no assurance whether, when or on what terms we will be able to successfully consummate any future acquisitions pursuant to our right of first offer, and Holdings is under no obligation to accept any offer that we may choose to make or to enter into any commercial agreements with us. For these or a variety of other reasons, we may decide not to exercise our right of first offer when we are permitted to do so, and our decision will not be subject to unitholder approval. In addition, our right of first offer may be, upon a change of control of our general partner, or by agreement between us and Holdings, terminated by Holdings at any time after it no longer controls our general partner.

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

If at any time our general partner and its affiliates own more than 80.0% of our then-outstanding common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price not less than their then-current market price. As a result, unitholders may be required to sell their common units at an undesirable time or price and may not receive any return on unitholders' investment. Unitholders may also incur a tax liability upon a sale of their units. As of March 8, 2017, Holdings and its affiliates own approximately 64.3% of our common units and therefore are not currently able to exercise the call right at that time.

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

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

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

As of December 31, 2016, there are only 4,226,315 publicly traded common units held by public unitholders. As of March 8, 2017, Holdings and CEP-TIR own 6,957,349 common units representing an aggregate 58.6% limited partner interest in us. We do not know how liquid our trading market might be. Additionally, the lack of liquidity may result in wide bid-ask spreads, contribute to significant fluctuations in the market price of the common units and limit the number of investors who are able to buy the common units.

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

Our general partner has the right, at any time units are outstanding and the holder of the incentive distribution rights has received distributions on its incentive distribution rights at the highest level to which it is entitled (50.0%) for each of the prior four consecutive fiscal quarters and the amount of such distribution did not exceed the adjusted operating surplus for such quarter, to reset the initial target distribution levels at higher levels based on our distributions at the time of the exercise of the reset election. Following a reset election, the minimum quarterly distribution will be adjusted to equal the reset minimum quarterly distribution, and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution.

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

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

Our common units trade on the NYSE. Because we are a publicly traded limited partnership, the NYSE does not require us to have a majority of independent directors on our general partner’s board of directors or to establish a compensation committee or a nominating and corporate governance committee. Additionally, any future issuance of additional common units or other securities, including to affiliates, will not be subject to the NYSE’s shareholder approval rules that apply to a corporation. Accordingly, unitholders will not have the same protections afforded to certain corporations that are subject to all of the NYSE corporate governance requirements.

The incentive distribution rights of our general partner may be transferred to a third party without unitholder consent.

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

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

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law, and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. A unitholder could be liable for any and all of our obligations as if a unitholder were a general partner if a court or government agency were to determine that unitholders' right to act with other unitholders to remove or replace our general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitute "control" of our business.

Tax Risks

Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes. If the Internal Revenue Service ("IRS") were to treat us as a corporation for U.S. federal income tax purposes, which would subject us to entity-level taxation, then our cash available for distribution to our unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in the common units depends largely on our being treated as a partnership for federal income tax purposes. We have not requested a ruling from the IRS with respect to our treatment as a partnership for U.S. federal income tax purposes.

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 U.S. federal income tax purposes. A change in our business or a change in current law could cause us to be treated as a corporation for U.S. federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35.0%, 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 a unitholder. Because a tax would be imposed upon us as a corporation, our cash available for distribution to a unitholder would be substantially reduced. Therefore, if we were treated as a corporation for federal income tax purposes, there would be a material reduction in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units.

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

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

Changes in current state, county or city law may subject us to additional entity-level taxation by individual states, countries or cities. Several states have subjected, or are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of any such taxes may substantially reduce the cash available for distribution to a unitholder. Our partnership agreement provides that, if a law is enacted or existing law is modified or interpreted in a manner that subjects us to entity-level taxation, the minimum quarterly distribution amount and the target distribution levels may be adjusted to reflect the impact of that law on us.

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

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial interpretation at any time. For example, members of Congress and the President have periodically considered substantive changes to the existing U.S. federal income tax laws that affect publicly traded partnerships, including the elimination of partnership tax treatment for publicly traded partnerships. Any modification to the U.S. federal income tax laws and interpretations thereof may or may not be retroactively applied and could make it more difficult or impossible to meet the qualifying income exception upon which we rely for our treatment as a partnership for U.S. federal income tax purposes. We are unable to predict whether any such changes will ultimately be enacted. However, it is possible that a change in law could affect us, and any such changes could negatively impact the value of an investment in our common units.

Our unitholders' share of our income will be taxable to them for U.S. 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.

If the IRS contests the U.S. 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 to our unitholders.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for U.S. federal income tax purposes. The IRS may adopt positions that differ from the 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 and such positions may not ultimately be sustained. A court may not agree with some or all of the positions we take. Any contest with the IRS, and the outcome of any IRS contest, may have a materially adverse impact on the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner, because the costs will reduce our cash available for distribution to our unitholders and for incentive distributions to our general partner.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after December 31, 2017, it may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment 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 may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us. Generally, we expect to elect to have our general partner and our unitholders take such audit adjustment into account in accordance with their interests in us during the tax year under audit, but there can be no assurance that such election will be effective in all circumstances. If we are unable to have our general partner and our unitholders take such audit adjustment into account in accordance with their interests in us during the tax year under audit, 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, penalties and interest, our cash available for distribution to our unitholders might be substantially reduced. These rules are not applicable to us 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 U.S. federal income tax purposes equal to the difference between the amount realized and their tax basis in those common units. Because distributions in excess of their allocable share of our net taxable income decrease their tax basis in their common units, the amount, if any, of such prior excess distributions with respect to the common units a unitholder sells will, in effect, become taxable income to the unitholder if it sells such common units at a price greater than its tax basis in those common units, even if the price received is less than its original cost. Furthermore, a substantial portion of the amount realized on any sale of unitholders' common units, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder's share of our nonrecourse liabilities, a unitholder that sells common units may incur a tax liability in excess of the amount of cash received from the sale.

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

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

Some of our activities may not generate qualifying income, and we conduct these activities in separate subsidiaries that are treated as corporations for U.S. federal income tax purposes. Corporate U.S. federal income taxes paid by these subsidiaries reduce our cash available for distribution.

In order to maintain our status as a partnership for U.S. federal income tax purposes, 90% or more of our gross income in each tax year must be qualifying income under Section 7704 of the Internal Revenue Code. To ensure that 90% or more of our gross income in each tax year is qualifying income, we currently conduct the portions of our business unrelated to these operations in separate subsidiaries that are treated as corporations for U.S. federal income tax purposes. These corporate subsidiaries will be subject to corporate-level tax, which reduces the cash available for distribution to us and, in turn, to our unitholders. If the IRS were to successfully assert that any corporate subsidiary has more tax liability than we anticipate or legislation were enacted that increased the corporate tax rate, our cash available for distribution to our unitholders would be further reduced.

We are in the process of requesting a ruling from the IRS upon which, if granted, we may rely with respect to the qualifying nature of the income from certain activities conducted by PIS and IS. If we do not obtain a favorable ruling from the IRS, we will be required to continue to conduct these activities in subsidiaries that are treated as corporations for U.S. federal income tax purposes and are subject to corporate-level income taxes.

We are in the process of requesting a ruling from the IRS upon which, if granted, we may rely with respect to the qualifying nature of the income from certain activities conducted by PIS and IS. If the IRS is unwilling or unable to provide a favorable ruling with respect to such income, we will continue to be subject to corporate-level tax on the revenues generated by such activities. Conversely, if the IRS does provide a favorable ruling, we may choose to conduct such activities in the future in a tax pass-through entity. Such restructuring may result in a significant, one-time tax liability and other costs, which will reduce our cash available for distribution.

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

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

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

We prorate our items of income, gain, loss and deduction for federal income tax purposes between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred.

The U.S. Department of Treasury and the IRS have issued Treasury Regulations that permit publicly traded partnerships to use a monthly simplifying convention that is similar to ours, but they do not specifically authorize all aspects of the proration method we have adopted. If the IRS were to successfully challenge this method, we could be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose common units are loaned to a "short seller" to effect a short sale of common units may be considered as having disposed of those common units. If so, he would no longer be treated for U.S. 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 a unitholder whose common units are loaned to a "short seller" to effect a short sale of common units may be considered as having disposed of the loaned common units, he may no longer be treated for U.S. 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 to the short seller, 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.

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, in certain circumstances, including when we issue additional units, we must 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 amount, character and timing of taxable income or loss allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

The sale or exchange of 50.0% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for U.S. federal income tax purposes.

We will be considered to have technically terminated our partnership for U.S. federal income tax purposes if there is a sale or exchange of 50.0% or more of the total interests in our capital and profits within a twelve month period. For purposes of determining whether the 50.0% threshold has been met, multiple sales of the same interest will be counted only once. Our technical termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns (and our unitholders could receive two Schedules K-1 if relief was not available, as described below) for one fiscal year and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for U.S. federal income tax purposes, but instead we would be treated as a new partnership for U.S. federal income tax purposes. If treated as a new partnership, we must make new tax elections, including a new election under Section 754 of the Internal Revenue Code, and could be subject to penalties if we are unable to determine that a termination occurred. The IRS has announced a publicly traded partnership technical termination relief program whereby, if a publicly traded partnership that technically terminated requests publicly traded partnership technical termination relief and such relief is granted by the IRS, among other things, the partnership will only have to provide one Schedule K-1 to unitholders for the year notwithstanding two partnership tax years.

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

In addition to U.S. federal income taxes, our unitholders are likely 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 are likely required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We currently own property or conduct business in many states, most of which impose an income tax on individuals, corporations and other entities. As we make acquisitions or expand our business, we may control assets or conduct business in additional states that impose a personal income tax. It is each unitholder’s responsibility to file all federal, state and local tax returns. Unitholders should consult their tax advisors.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Not Applicable.

ITEM 2. PROPERTIES

Our Properties

As of December 31, 2016, W&ES had an aggregate of approximately 115,000 barrels of maximum daily disposal capacity in the following SWD facilities, all of which were built since June 2011 with most having new well bores, using completion techniques consistent with current industry practices and utilizing well depths of at least 5,000 feet and injection intervals beginning at least 4,000 feet beneath the surface:

Location	County	In-service Date	Leased / Owned (3)
Tioga, ND	Williams	June 2011	Owned
Manning, ND	Dunn	December 2011	Owned
Grassy Butte, ND	McKenzie	May 2012	Leased
New Town, ND (1)	Mountrail	June 2012	Leased
Pecos, TX (1)	Reeves	July 2012	Owned
Williston, ND	Williams	August 2012	Owned
Stanley, ND	Mountrail	September 2012	Owned
Orla, TX (1)	Reeves	September 2012	Owned
Belfield, ND	Billings	October 2012	Leased
Watford City, ND (1), (2)	McKenzie	May 2013	Leased
Arnegard, ND (1)	McKenzie	August 2014	Leased

(1) Currently receives piped water.
(2) We own a 25.0% non-controlling interest in this SWD facility.
(3) Some facilities are constructed on land that is leased under long-term arrangements.

We lease general office space at our corporate headquarters located at 5727 S. Lewis Avenue, Suite 300, Tulsa, Oklahoma 74105. The lease expires in February 2018 unless terminated earlier under certain circumstances specified in our lease. In our PIS segment, we also lease office space in Calgary, Alberta, Canada for our Canadian operations that expires April 30, 2017. Our IS segment owns an office building and staging and storage facility in Giddings, Texas.

ITEM 3. LEGAL PROCEEDINGS

Stuart v. TIR

In July 2014, a group of former minority shareholders of Tulsa Inspection Resources, Inc. ("TIR Inc."), formerly an Oklahoma corporation, filed a civil action in the United States District Court for the Northern District of Oklahoma against TIR LLC, members of TIR LLC, and certain affiliates of TIR LLC's members. TIR LLC is the successor in interest to TIR Inc., resulting from a merger between the entities that closed in December 2013 (the "TIR Merger"). The former shareholders in TIR Inc. claim that they did not receive sufficient value for their shares in the TIR Merger and are seeking rescission of the TIR Merger or, alternatively, compensatory and punitive damages. The Partnership is not named as a defendant in this civil action. The Partnership anticipates no disruption in its business operations related to this action.

Flatland Resources v. CES LLC

In September 2015, Flatland Resources I, LLC and Flatland Resources II, LLC, two of our management services customers (under common ownership) initiated a civil action in the District Court for the McKenzie County District of the State of North Dakota against CES LLC. The customers claim that CES LLC breached the management agreements and interfered with their business relationships, and seek to rescind the management agreements and recover any damages. The customers initiated this lawsuit upon dismissal from federal court due to lack of jurisdiction of CES LLC's lawsuit against the customers seeking to enforce the management agreements. CES LLC subsequently filed an answer and counterclaims, as well as a third party complaint against the principal of the customers seeking to enforce the management agreements and other injunctive relief, as well as monetary damages. The court subsequently granted CES's motion to transfer venue to the Grand Forks County District Court. In the first quarter of 2017, CES received a cash payment and other consideration and the parties settled the matter and dismissed all associated claims.

Other

From time to time, we are subject to legal proceedings and claims that arise in the ordinary course of business. Like other organizations, our operations are subject to extensive and rapidly changing federal and state environmental, health and safety and other laws and regulations governing air emissions, wastewater discharges, and solid and hazardous waste management activities.

We are not a party to any other material pending or overtly threatened legal or governmental proceedings, other than proceedings and claims that arise in the ordinary course and are incidental to our business.

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED UNITHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common units are listed on the NYSE under the symbol "CELP."

On March 8, 2017, the closing price for the common units was $12.14 per unit and there were approximately 3,700 unitholders of record and beneficial owners (held in street name) of the Partnership's common units. The Partnership will issue approximately 6,200 federal K-1s to unitholders of record for 2016.

In addition to our common units issued at our IPO date, we also issued 5,913,000 subordinated units, for which there was no established public trading market. As of December 31, 2016, 5,612,699 of the subordinated units were effectively held by Holdings and its controlled affiliates, either directly or indirectly through its ownership of CEP-TIR. The remaining 300,301 subordinated units were held directly by certain beneficial owners and management. With the payment of the February 2017 quarterly distribution and the fulfillment of other requirements as provided in the partnership agreement, on February 14, 2017 the subordination period with respect to our 5,913,000 subordinated units expired and all outstanding subordinated units converted to common units on a one-for-one basis. Prior to the conversion date, the subordinated units were not entitled to receive distributions until the common units received the minimum quarterly distribution of $0.3875 per common unit plus any arrearages from prior quarters. The conversion did not impact the total number of our outstanding units representing limited partner interests.

The high and low trading prices for our common units and distribution paid per unit by quarter were as follows:

Quarter Ended	High	Low	Distribution (a)
March 31, 2014	$26.00	$19.55	$0.301389 (b)
June 30, 2014	24.97	21.65	0.396844
September 30, 2014	25.78	22.22	0.406413
December 31, 2014	24.93	11.54	0.406413
March 31, 2015	19.83	11.82	0.406413
June 30, 2015	18.00	12.41	0.406413
September 30, 2015	16.64	9.21	0.406413
December 31, 2015	12.99	7.02	0.406413
March 31, 2016	10.73	5.28	0.406413
June 30, 2016	10.27	7.34	0.406413
September 30, 2016	12.36	8.04	0.406413
December 31, 2016	11.69	8.99	0.406413

(a) Represents declared distributions associated with each respective quarter. Distributions were declared and paid within 45 days following the close of each quarter in accordance with our cash distribution policy.

(b) Reflects a pro-rated portion of the targeted minimum quarterly cash distribution of $0.3875 for the period from the closing of the Partnership's IPO on January 21, 2014 through March 31, 2014.

Our Cash Distribution Policy

Our partnership agreement requires that, within 45 days after the end of each quarter, we distribute all of our available cash to unitholders of record on the applicable record date. It is the Partnership's intent to continue to make cash distributions to unitholders on a quarterly basis, however, the Partnership makes no representation or assurances as to the availability of future cash distributions since they are dependent upon future earnings, cash flows, capital requirements, financial condition and other factors.

Definition of Available Cash

Available cash, for any quarter, consists of all cash and cash equivalents on hand at the end of that quarter:

less , the amount of cash reserves established by our general partner at the date of determination of available cash for the quarter to:

provide for the proper conduct of our business, which could include, but is not limited to, amounts reserved for capital expenditures, working capital and operating expenses;

comply with applicable law, any of our debt instruments or other agreements; or

provide funds for distributions to our unitholders (including our general partner) for any one or more of the next four quarters;

plus , if our general partner so determines, all or a portion of cash on hand on the date of determination of available cash for the quarter, including cash on hand resulting from working capital borrowings made after the end of the quarter.

Distributions

Although it is the Partnership's policy to continue to make cash distributions to unitholders on a quarterly basis, the Partnership makes no representation or assurances as to the availability of future cash distributions since they are dependent upon future earnings, cash flows, capital requirements, financial condition and other factors. It is currently anticipated that our cash distributions will be reduced by fifty percent until the board of directors determines that an increase would be appropriate. Our partnership agreement requires that we make distributions of available cash from operating surplus for any quarter in the following manner:

- *first,* 100.0% to all unitholders, pro rata, until we distribute for each outstanding unit an amount equal to the minimum quarterly distribution for that quarter; and
- *thereafter,* in the manner described in "*General Partner Interest and Incentive Distribution Rights*" below.

The preceding discussion is based on the assumptions that we do not issue additional classes of equity securities.

General Partner Interest and Incentive Distribution Rights

Incentive distribution rights ("IDRs") represent the right to receive an increasing percentage of quarterly distributions of available cash from operating surplus after the minimum quarterly distribution and the target distribution levels have been achieved. The IDRs are effectively held by the same ownership group that own and control our general partner.

The following discussion assumes there are no arrearages on common units.

If for any quarter we have distributed available cash from operating surplus to the common unitholders in an amount equal to the minimum quarterly distribution, then, our partnership agreement requires that we distribute any additional available cash from operating surplus for that quarter among the unitholders and the owner(s) of the IDRs in the following manner:

- first, 100.0% to all unitholders, pro rata, until each unitholder receives a total of $0.445625 per unit for that quarter (the "first target distribution");
- second, 85.0% to all unitholders, pro rata, and 15.0% to the owner(s) of the IDRs, until each unitholder receives a total of $0.484375 per unit for that quarter (the "second target distribution"); and
- third, 75.0% to all unitholders, pro rata, and 25.0% to the owner(s) of the IDRs, until each unitholder receives a total of $0.581250 per unit for that quarter (the "third target distribution"); and
- thereafter, 50.0% to all unitholders, pro rata, and 50.0% to the owner(s) of the IDRs.

Securities Authorized for Issuance under Equity Compensation Plans

See "Item 12 — Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters" for information regarding our equity compensation plans as of December 31, 2016.

Unregistered Sales of Equity Securities

None not previously reported on a current report on Form 8-K.

Issuer Purchases of Equity Securities

None.

ITEM 6. SELECTED FINANCIAL DATA

The following table should be read together with "*Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations*" and the historical financial statements and accompanying notes included in "*Item 8 – Financial Statements and Supplementary Data*."

Cypress Energy Partners, L.P. (the "Partnership") is a Delaware limited partnership formed in 2013 to provide independent pipeline inspection and integrity services to producers and pipeline companies and to provide saltwater disposal ("SWD") and other water and environmental services to U.S. onshore oil and natural gas producers and trucking companies. Trading of our common units began January 15, 2014 on the New York Stock Exchange under the symbol "CELP." At our Initial Public Offering ("IPO"), 4,312,500 of our common units were sold to the general public. The remaining common units and 100% of the subordinated units were constructively owned by affiliates, employees, and directors of the Partnership. With the payment of the February 2017 quarterly distribution and the fulfillment of other requirements provided in the partnership agreement, on February 14, 2017 the subordination period with respect to our 5,913,000 subordinated units expired and all outstanding subordinated units converted to common units on a one-for-one basis. In connection with the IPO, Holdings II, a wholly-owned subsidiary of Holdings, conveyed a 100% interest in CEP LLC. Prior to its contribution to the Partnership, CEP LLC distributed to Holdings its interest in four subsidiaries. In addition to CEP LLC, affiliates of Holdings contributed 50.1% of their interest in the TIR Entities (the Partnership's PIS segment). The Partnership then subsequently conveyed this 50.1% interest to CEP LLC. We have recast prior period financial data and information of Cypress Energy Partners, L.P. to reflect CEP LLC's distribution of its four subsidiaries to Holdings, which were originally acquired on December 31, 2012, and to reflect the conveyance of CEP LLC and the TIR Entities to the Partnership at the closing of our IPO, as if the contribution of CEP LLC had occurred as of March 15, 2012 and the contribution of the TIR Entities had occurred as of June 26, 2013, the date affiliated members of the Partnership acquired a controlling interest in the TIR Entities. Effective February 1, 2015, the Partnership acquired the remaining 49.9% interest in the TIR Entities previously held by affiliates of Holdings. Effective May 1, 2015, the Partnership acquired a 51% interest in Brown Integrity, LLC, a hydrostatic testing integrity services business creating our IS segment.

The following table also presents Adjusted EBITDA, which we use in evaluating the performance and liquidity of our business. This financial measure is not calculated or presented in accordance with generally accepted accounting principles, or GAAP. We explain this measure below and reconcile it to net income and net cash from operating activities, its most directly comparable financial measures calculated and presented in accordance with GAAP.

	Cypress Energy Partners, L.P.					Predecessor (d)
	Year Ended December 31, 2016	Year Ended December 31, 2015 (a)	Year Ended December 31, 2014	Year Ended December 31, 2013 (b) Recast	Period from March 15 (Inception) through December 31, 2012 (c) Recast	Year Ended December 31, 2012
	(in thousands, except cash distributions per unit and operational data)					
Income Statement Data						
Revenues	$ 297,997	$ 371,191	$ 404,418	$ 249,133	$ 619	$ 12,203
Costs of services	262,517	326,261	355,355	213,690	309	3,662
Gross margin	35,480	44,930	49,063	35,443	310	8,541
General and administrative expense	21,853	23,795	21,321	12,467	2,056	477
Depreciation, amortization and accretion	4,861	5,427	6,345	5,164	99	1,398
Impairments	10,530	6,645	32,546	4,131	—	—
Operating income (loss)	(1,764)	9,063	(11,149)	13,681	(1,845)	6,666
Interest expense, net	6,559	5,656	3,208	4,000	—	111
Offering costs	—	—	446	1,376	—	—
Net income (loss)	(9,162)	4,091	(15,179)	4,355	(1,845)	6,595
Net income attributable to non-controlling interests	(4,499)	599	4,973	22	—	—
Net income (loss) attributable to partners / controlling interests	(4,663)	3,492	(20,152)	4,333	—	—
Balance sheet Data - Period End						
Total assets	$ 167,512	$ 190,882	$ 187,524	$ 238,441	$ 79,990	$ 27,588
Long-term debt	135,699	139,129	75,282	72,851	—	2,314
Total parent net investment and owners' equity	19,388	40,702	100,428	135,547	77,746	24,769
Cash Flow Data						
Cash flows from operating activities	$ 24,819	$ 26,921	$ 13,016	$ 7,154	$ (2,244)	$ 7,246
Cash flows from investing activities	(1,330)	(64,879)	(2,286)	5,779	(65,613)	(15,236)
Cash flows from financing activities	(21,289)	42,501	(16,030)	13,363	68,341	8,425
Cash distributions per unit (subsequent to IPO) (e)	1.63	1.63	1.51	—	—	—

Capital expenditures	1,376	1,857	2,286	4,329	65,613	15,236
Other Financial Data						
Adjusted EBITDA	$ 19,794	$ 24,663	$ 28,499	$ 23,110	$ (1,746)	$ 8,104
Adjusted EBITDA attributable to limited partners / controlling interests	22,238	23,147	18,190	23,079	(1,746)	8,104
Operational Data						
Average number of inspectors (PIS segment)	1,147	1,392	1,535	1,706		
Average revenue per inspector per week	$ 4,601	$ 4,711	$ 4,773	$ 4,952		
Average number of field personnel (IS segment)	23	33				
Average revenue per field personnel per week	$ 11,577	$ 12,653				
Total barrels of saltwater disposed (in thousands)	13,307	18,864	19,066	19,541	551	8,674
Average revenue per barrel	$ 0.67	$ 0.78	$ 1.18	$ 1.14	$ 1.12	$ 1.41

(a) Activity for the year ended December 31, 2015 includes operations of Brown (IS segment) from the May 1, 2015 acquisition date to the end of the year.

(b) Activity for the year ended December 31, 2013 includes operations of the TIR Entities (PIS segment from the June 26, 2013 acquisition date through the end of the year.

(c) During the period from its inception through the date of its acquisition of the Predecessor on December 31, 2012, CEP LLC had no significant assets or operations.

(d) Includes activities of certain entities that were not contributed to the Partnership.

(e) Includes February distributions related to the previous quarter ended December 31.

Non-GAAP Financial Measures

We define Adjusted EBITDA as net income (loss); plus interest expense; depreciation, amortization and accretion expenses; income tax expense; impairments; non-cash allocated expenses; offering costs; and equity-based compensation expense. We define Adjusted EBITDA attributable to limited partners as net income (loss) attributable to limited partners; plus interest expense attributable to limited partners; depreciation, amortization and accretion expenses attributable to limited partners; impairments attributable to limited partners; income tax expense attributable to limited partners; offering costs attributable to limited partners; non-cash allocated expenses attributable to limited partners; and equity-based compensation attributable to limited partners. We define Distributable Cash Flow as Adjusted EBITDA attributable to limited partners excluding cash interest paid, cash income taxes paid and maintenance capital expenditures. Adjusted EBITDA, Adjusted EBITDA attributable to limited partners and Distributable Cash Flow are used as supplemental financial measures by management and by 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;
- our ability to incur and service debt and fund capital expenditures;
- 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 the presentation of these non-GAAP measures provide useful information to investors in assessing our financial condition and results of operations. The GAAP measures most directly comparable to Adjusted EBITDA, Adjusted EBITDA attributable to limited partners' and Distributable Cash Flow are net income (loss) and cash flow from operating activities. These non-GAAP measures should not be considered as alternatives to the most directly comparable GAAP financial measure. Each of these non-GAAP measures exclude some, but not all, items that affect the most directly comparable GAAP financial measure. Adjusted EBITDA, Adjusted EBITDA attributable to limited partners and Distributable Cash Flow should not be considered alternatives to net income (loss), income (loss) before income taxes, net income (loss) attributable to limited partners, cash flows from operating activities, or any other measure of financial performance calculated in accordance with GAAP, as those items are used to measure operating performance, liquidity, or the ability to service debt obligations.

Because Adjusted EBITDA, Adjusted EBITDA attributable to limited partners, and Distributable Cash Flow may be defined differently by other companies in our industry, our definitions of Adjusted EBITDA, Adjusted EBITDA attributable to limited partners, and Distributable Cash Flow may not be comparable to a similarly titled measure of other companies, thereby diminishing their utility.

The following tables present a reconciliation of *net income (loss)* to Adjusted EBITDA and to Distributable Cash Flow, a reconciliation of *net income (loss) attributable to limited partners* to Adjusted EBITDA attributable to limited partners and to Distributable Cash Flow, and a reconciliation of *net cash provided by operating activities* to Adjusted EBITDA and to Distributable Cash Flow for each of the periods indicated.

Reconciliation of Net Income (Loss) to Adjusted EBITDA and to Distributable Cash Flow

	Years ended December 31,		
	2016	2015 (a)	2014
	(in thousands)		
Net income (loss)	$(9,162)	$4,091	$(15,179)
Add:			
Interest expense	6,559	5,656	3,208
Depreciation, amortization and accretion	5,788	6,004	6,513
Impairments	10,530	6,645	32,546
Income tax expense	1,195	452	468
Non-cash allocated expenses	3,798	648	497
Offering costs	—	—	446
Equity based compensation	1,086	1,167	—
Adjusted EBITDA	$19,794	$24,663	$28,499
Adjusted EBITDA attributable to general partner	(2,500)	—	1,651
Adjusted EBITDA attributable to non-controlling interests	56	1,516	8,658
Adjusted EBITDA attributable to limited partners / controlling interests	$22,238	$23,147	$18,190
Less:			
Cash interest paid, cash taxes paid, maintenance capital expenditures	6,717	5,940	381
Distributable cash flow	$15,521	$17,207	$17,809

(a) The Partnership acquired a 51% ownership interest in Brown effective May 1, 2015. Due to this, amounts for the year ended December 31, 2015 include Brown from this date forward. The Partnership acquired the remainder of the TIR Entities February 1, 2015. Adjusted EBITDA attributable to non-controlling interests for the year ended December 31, 2015 includes the activity of the TIR Entities through its acquisition date.

Reconciliation of Net Income (Loss) Attributable to Limited Partners to Adjusted EBITDA Attributable to Limited Partners and to Distributable Cash Flow

	Years ended December 31,		
	2016	2015 (a)	2014
	(in thousands)		
Net income (loss) attributable to limited partners	$1,635	$4,140	$(20,301)
Add:			
Interest expense attributable to limited partners	6,556	5,290	861
Depreciation, amortization and accretion attributable to limited partners	5,373	5,522	4,849
Impairments attributable to limited partners	6,409	6,645	32,546

Income tax expense attributable to limited partners	1,179	383	235
Equity based compensation attributable to limited partners	1,086	1,167	—
Adjusted EBITDA attributable to limited partners	22,238	23,147	18,190
Less:			
Cash interest paid, cash taxed paid and maintenance capital expenditures	6,717	5,940	381
Distributable cash flow	$15,521	$17,207	$17,809

(a) The Partnership acquired a 51% ownership interest in Brown effective May 1, 2015. Due to this, amounts for the year ended December 31, 2015 include Brown from this date forward. The Partnership acquired the remainder of the TIR Entities February 1, 2015. Adjusted EBITDA attributable to limited partners for the year ended December 31, 2015 includes the activity of the TIR Entities through its acquisition date.

51

Reconciliation of Net Cash Provided by Operating Activities to Adjusted EBITDA and to Distributable Cash Flow

	Years ended December 31,		
	2016(a)	2015 (a)	2014
	(in thousands)		
Cash flows provided by operating activities	$24,819	$26,921	$13,016
Changes in trade accounts receivable, net	(9,871)	(9,039)	(6,650)
Changes in prepaid expenses and other	(1,350)	(233)	933
Changes in accounts payable and accrued liabilities	(478)	1,222	2,964
Change in income taxes payable	(662)	196	15,612
Offering costs	—	—	446
Equity-based compensation	—	—	(785)
Interest expense (excluding non-cash interest)	5,989	5,109	2,494
Income tax expense (excluding deferred tax benefit)	1,219	484	468
Other	128	3	1
Adjusted EBITDA	$19,794	$24,663	$28,499
Adjusted EBITDA attributable to general partner	(2,500)	—	1,651
Adjusted EBITDA attributable to non-controlling interests	56	1,516	8,658
Adjusted EBITDA attributable to limited partners / controlling interests	$22,238	$23,147	$18,190
Less:			
Cash interest paid, cash taxes paid, maintenance capital expenditures	6,717	5,940	381
Distributable cash flow	$15,521	$17,207	$17,809

(a) The Partnership acquired a 51% ownership interest in Brown effective May 1, 2015. Due to this, amounts for the year ended December 31, 2015 include Brown from this date forward.

52

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

This Management's Discussion and Analysis of Financial Condition and Results of Operations contains a discussion of our business, including a general overview of our properties, our results of operations, our liquidity and capital resources, and our quantitative and qualitative disclosures about market risk. At the closing of our IPO on January 21, 2014, CEP LLC and a 50.1% interest in the TIR Entities were contributed to us and became our Water and Environmental Services ("W&ES") segment and our Pipeline Inspection Services ("PIS") segment, respectively. These contributions were treated for accounting purposes as a combination of entities under common control and the results of CEP LLC are included as if the contributions had occurred as of March 15, 2012 and the results of the TIR Entities were included in our financial statements for periods subsequent to June 26, 2013, the date Holdings acquired a controlling interest. Brown Integrity, LLC (our Integrity Services ("IS") segment) was acquired effective May 1, 2015, and the results of this segment have been included in our financial statements for periods subsequent to that date.

The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control, including among other things, the risk factors discussed in "Item 1A. Risk Factors" of this Annual Report on Form 10-K. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for oil and natural gas, production volumes, estimates of proved reserves, capital expenditures, economic and competitive conditions, regulatory changes and other uncertainties, as well as those factors discussed below and elsewhere in this Annual Report on Form 10-K, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. See "Cautionary Remarks Regarding Forward-Looking Statements" in the front of this Annual Report on Form 10-K.

Overview

We are a growth-oriented master limited partnership formed in September 2013 to provide services to the oil and gas industry. We provide independent pipeline inspection and integrity services to various energy exploration and production ("E&P") and midstream companies and their vendors in our PIS and IS segments throughout the United States and Canada. The PIS segment is comprised of the operations of the TIR Entities and the IS segment is comprised of the operations of Brown. We also provide SWD and other water and environmental services to U.S. onshore oil and natural gas producers and trucking companies through our W&ES segment. The W&ES segment is comprised of the historical operations of CEP LLC that were contributed to us. We operate ten SWD facilities, eight of which are in the Bakken Shale region of the Williston Basin in North Dakota and two of which are in the Permian Basin in west Texas. We also have a management agreement in place to provide staffing and management services to one 25%-owned SWD facility in the Bakken Shale region. In all of our business segments, we work closely with our customers to help them comply with increasingly complex and strict environmental and safety rules and regulations applicable to production and pipeline operations, assisting in reducing their operating costs.

How We Generate Revenue

We generate revenue in the PIS segment primarily by providing inspection services on midstream pipelines, gathering systems, and distribution systems, including data gathering and supervision of third-party construction, inspection, and maintenance and repair projects. Our results in this segment are driven primarily by the number of inspectors that perform services for our customers and the fees that we charge for those services, which depend on the type and number of inspectors used on a particular project, the nature of the project, and the duration of the project. The number of inspectors engaged on projects is driven by the type of project, prevailing market rates, the age and condition of customers' midstream pipelines, gathering systems, and distribution systems, and the legal and regulatory requirements relating to the inspection and maintenance of those assets. We charge our customers on a per-inspector basis, including per diem charges, mileage, and other reimbursement items.

We generate revenue in our IS segment primarily by providing hydrostatic testing services to major natural gas and petroleum companies and pipeline construction companies. We perform these services on newly-constructed and existing natural gas and petroleum pipelines. We generally charge our customers in this segment on a fixed-bid basis. Bid prices vary based on the size and length of the pipeline being inspected, the complexity of services provided, and the utilization of our work force and equipment. Our results in this segment are driven primarily by the number of field personnel that perform services for our customers, the fees that we charge for those services (which depend on the type and number of field personnel used on a particular project), the type of equipment used and the fees charged for the utilization of that equipment, and the nature and duration of the project.

We generate revenue in the W&ES segment primarily by treating flowback and produced water and injecting the saltwater into our SWD facilities. Our results in W&ES are driven primarily by the volumes of produced water and flowback water we receive and the fees we charge for our services. These fees are charged on a per-barrel basis under contracts that are short-term in nature and vary based on the quantity and type of saltwater disposed, competitive dynamics, and operating costs. The volumes of saltwater disposed at our SWD facilities are driven by water volumes generated from existing oil and natural gas wells during their useful lives and development drilling and production volumes from the wells located near our facilities. Producers' willingness to engage in new drilling is determined by a number of factors, the most important of which are the prevailing and projected prices of oil, natural gas, and NGLs, the cost to drill and operate a well, the availability and cost of capital, and environmental and governmental regulations. We generally expect the level of drilling to positively correlate with long-term trends in prices of oil, natural gas, and NGLs. Revenues in this segment are recognized when the service is performed and collectability of fees is reasonably assured. We also generate revenue for managing an SWD facility.

In addition, for minimal marginal cost, we generate revenue by selling residual oil we recover from the flowback and produced water. Our ability to recover residual oil is dependent upon the residual oil content in the saltwater we treat, which is, among other things, a function of water type, chemistry, source, and temperature. Generally, where outside temperatures are lower, there is less residual oil content and separation is more difficult. Thus, our residual oil recovery during the winter season is usually lower than our recovery during the summer season in North Dakota. Additionally, residual oil content will decrease if, among other things, producers begin recovering higher levels of residual oil in saltwater prior to delivering such saltwater to us for treatment.

How We Evaluate Our Operations

Our management uses a variety of financial and operating metrics to analyze our performance. We view these metrics as significant factors in assessing our operating results and profitability and intend to review these measurements frequently for consistency and trend analysis. These metrics include:

- inspector headcount in PIS;
- field personnel headcount and utilization in IS;
- saltwater disposal and residual oil volumes in W&ES;
- operating expenses;
- segment gross margin;
- safety metrics;
- Adjusted EBITDA;
- maintenance and expansion capital expenditures; and
- distributable cash flow.

Inspector Headcount

The amount of revenue we generate in PIS depends primarily on the number of inspectors that perform services for our customers. The number of inspectors engaged on projects is driven by the type of project, prevailing market rates, the age and condition of customers' midstream pipelines, gathering systems, miscellaneous infrastructure, distribution systems, and the legal and regulatory requirements relating to the inspection and maintenance of those assets.

Field Personnel Headcount and Utilization

The amount of revenue we generate in IS depends primarily on the number of field personnel that perform services for our customers and the fees that we charge for those services, which depend on the type and number of field personnel used on a particular project, the type of equipment used and the fees charged for the utilization of that equipment, and the nature and the duration of the project. The number of field personnel engaged on projects is driven by the type of project, the size and length of the pipeline being inspected, the complexity of services provided, and the utilization of our work force and equipment.

Saltwater Disposal and Residual Oil Volumes

The amount of revenue we generate in W&ES depends primarily on the volume of produced water and flowback water that we dispose for our customers pursuant to published or negotiated rates, as well as the volume of residual oil that we sell pursuant to rates that are determined based on the quality of the oil sold and prevailing oil prices. Our revenues from produced water, flowback water, and residual oil sales are generated pursuant to contracts that are short-term in nature. Revenues in this segment are recognized when the service is performed and collectability of fee is reasonably assured. The volumes of saltwater disposed at our SWD facilities are driven by water volumes generated from existing oil and natural gas wells during their useful lives and development drilling and production volumes from the wells located near our facilities. Producers' willingness to engage in new drilling is determined by a number of factors, the most important of which are the prevailing and projected prices of oil, natural gas, and NGLs, the cost to drill and operate a well, the availability and cost of capital and environmental and governmental regulations. We generally expect the level of drilling to positively correlate with long-term trends in prices of oil, natural gas, and NGLs.

Approximately 6%, 8%, and 22% of our W&ES segment revenue for the years ended December 31, 2016, 2015 and 2014, respectively, was derived from sales of residual oil recovered during the saltwater treatment process. Our ability to recover residual oil is dependent upon the oil content in the saltwater we treat, which is, among other things, a function of water type, chemistry, source, and temperature. Generally, where outside temperatures are lower, oil separation is more difficult. Thus, our residual oil recovery during the winter season is lower than our recovery during the summer season in North Dakota. Additionally, residual oil content will decrease if, among other things, producers begin recovering higher levels of residual oil in saltwater prior to delivering such saltwater to us for treatment.

Operating Expenses

The primary components of our operating expenses that we evaluate include costs of services, general and administrative, and depreciation and amortization.

Costs of services. Employee-or-contractor-related costs and per diem expenses are the primary costs of services components in PIS and IS. These expenses fluctuate from period to period based on the number, type, and location of projects on which we are engaged at any given time. We seek to maximize the profitability of our operations in part by minimizing, to the extent appropriate, expenses directly tied to operating and maintaining our assets. Repair and maintenance costs, employee-related costs, residual oil disposal costs, lease expenses, and utility expenses are the primary cost of services components in W&ES. These expenses generally remain relatively stable across broad ranges of saltwater disposal volumes but can fluctuate from period to period depending on the mix of activities performed during that period and the timing of these expenses.

General and administrative. General and administrative expenses include management and overhead payroll, general office expenses, management fees, legal fees, and other expenses.

Under our amended and restated omnibus agreement, Holdings charges us an annual administrative fee of $4.0 million (payable in equal quarterly installments) for the provision of certain partnership overhead expenses. This fee is subject to an increase by an annual amount equal to PPI plus one percent or, with the concurrence of the conflicts committee, in the event of an expansion of our operations, including through acquisitions or internal growth. To the extent that Holdings incurs overhead expenses in excess of our annual administrative fee that are attributable to the operations of the Partnership, these expenses are reported in our Consolidated Statements of Operations within *general and administrative expense* and as an equity *contribution attributable to our General Partner* in our Consolidated Statement of Equity.

Included in this administrative fee are general and administrative expenses attributable to operating as a publicly traded partnership, such as expenses associated with annual and quarterly SEC reporting; tax return and Schedule K-1 preparation and distribution expenses; Sarbanes-Oxley compliance; listing on the New York Stock Exchange; independent registered public accounting firm fees; certain legal fees; investor relations, registrar, and transfer agent fees; director and officer liability insurance costs; and director compensation. Our partnership agreement provides that Holdings will determine and allocate expenses related to our operations and may provide us other services for which we will be charged fees as determined in good faith. Payments to Holdings and its affiliates following the terminiation of our amended and restated omnibus agreement could be substantial and will reduce the amount of cash we have available to distribute to unitholders.

During the year ended December 31, 2016, Holdings provided sponsor support to the Partnership by waiving payment of the quarterly administrative fee. We reported the amount of the waived fee within *general and administrative expense* in our consolidated statement of operations and as an equity contribution in our consolidated statement of equity.

Depreciation, amortization and accretion Depreciation, amortization and accretion expense primarily consists of our estimate of the decrease in value of our capitalized tangible and intangible assets as a result of using the assets over time. Depreciation and amortization are recorded on a straight-line basis. We estimate our assets have useful lives ranging from 3 to 39 years. The facilities, wells, and equipment of our W&ES Segment constituted approximately 60% and 75% of the net book value of our fixed assets as of December 31, 2016 and 2015, respectively, and generally have useful lives of 5 to 15 years.

Segment Gross Margin, Adjusted EBITDA and Distributable Cash Flow

We view segment gross margin as one of our primary management tools, and we track this item on a regular basis, both as an absolute amount and as a percentage of revenues compared to prior periods. We also track Adjusted EBITDA, defined as net income (loss) plus interest expense, depreciation and amortization expense, income tax expense, offering costs, impairments, non-cash allocated expenses, and equity-based compensation. We use distributable cash flow, defined as Adjusted EBITDA less net cash interest paid, cash taxes paid, and maintenance capital expenditures, as an additional measure to analyze our performance. Distributable cash flow does not reflect changes in working capital balances, which could be significant, as headcounts of PIS vary from period to period. Adjusted EBITDA and distributable cash flow are non-GAAP, supplemental financial measures used by management and by external users of our financial statements, such as investors, lenders, and analysts, to assess:

- our operating performance as compared to those of other providers of similar services, without regard to financing methods, historical cost basis, or capital structure;
- the ability of our assets to generate sufficient cash flow to support our indebtedness and make distributions to our partners;
- the viability of capital expenditure projects and the overall rates of return on alternative investment opportunities;
- our ability to incur and service debt and fund capital expenditures; and
- the viability of acquisitions and other capital expenditure projects and the rates of return on various investment opportunities.

Adjusted EBITDA and distributable cash flow are not financial measures presented in accordance with GAAP. We believe that the presentation of these non-GAAP financial measures provides useful information to investors in assessing our financial condition and results of operations. Net income is the GAAP measure most directly comparable to Adjusted EBITDA. The GAAP measure most directly comparable to distributable cash flow is net cash provided by operating activities. Our non-GAAP financial measures should not be considered as alternatives to the most directly comparable GAAP financial measure. Each of these non-GAAP financial measures has important limitations as an analytical tool because it excludes some, but not all, of the items that affect the most directly comparable GAAP financial measure. You should not consider Adjusted EBITDA or distributable cash flow in isolation or as a substitute for analysis of our results as reported under GAAP. Because Adjusted EBITDA and distributable cash flow may be defined differently by other companies in our industry, our definitions of these non-GAAP financial measures may not be comparable to similarly titled measures of other companies, thereby diminishing their utility.

For a further discussion of the non-GAAP financial measures of Adjusted EBITDA and reconciliation of that measure to their most comparable financial measures calculated and presented in accordance with GAAP, please read “ *Item 6 — Selected Financial Data — Non-GAAP Financial Measures*.”

Outlook

In January 2017, a lightning strike at our Orla SWD facility initiated a fire that effectively destroyed the surface equipment at the facility. Due to the aftereffects of the fire, we were required to perform some environmental remediation and reclamation at the facility. All appropriate governmental agencies were contacted and informed of our remediation procedures. Temporary operations were established within 11 days of the incident in order to minimize the disruption of business at this facility. We are currently working with our insurance providers to complete remediation and reconstruct the SWD facility (we have minimal deductibles related to our pollution and property coverage at this facility). Currently, we anticipate that the facility will be rebuilt by the third quarter of 2017.

In early March 2017, the largest customer of our Canadian subsidiary (in our PIS segment) completed its bid process and they selected new service providers offering more aggressive terms for their major projects (although we continue to perform work for this customer on smaller integrity projects). In Canada, the inspectors are independent contractors for Canadian tax reasons instead of employees and therefore change is easier to implement for inspection clients. During the year ended December 31, 2016, we generated approximately $25.0 million of revenue and $1.7 million of gross margin from inspection work for this customer, which represented approximately 81% of the revenues and 81% of the gross margin of our Canadian subsidiary (this work represented approximately 8.4% of our consolidated revenues and 4.9% of our consolidated gross margin for the year ended December 31, 2016). We are currently evaluating our options related to the future of our Canadian subsidiary. Our Canadian operations have been challenging for several years. We have been focused on improving our margin and mix of business for the last several years as seen in our operating results.

In February 2017, the Partnership paid the fourth quarter 2016 distribution, the amount of which was the same as for the past nine quarters. Operating results in the fourth quarter of 2016 were improved over results in the fourth quarter of 2015. The Partnership is seeing the benefits of cost reductions implemented early in 2016 and each quarter's operating results throughout 2016 reflected sequential improvements. During 2016, Holdings voluntarily supported the Partnership by waiving the $4.0 million fee that otherwise would have been payable under the omnibus agreement and by contributing an additional $2.5 million for reimbursement of expenses incurred by the Partnership. Holdings could have received consideration for this financial support, however, it did not request any consideration from the Partnership.

In light of these developments, and softening commodity prices our board now believes it is prudent and responsible to make the difficult decision to reduce our quarterly distribution for the first time since our initial public offering in January of 2014. Absent an acquisition in the near future, we currently anticipate reducing the current distribution by approximately 50%. The exact amount, record date, and payment date of the distribution will be determined by the Board after review of first quarter results. If this distribution level is maintained throughout fiscal 2017, compared to the previous distribution level of $0.406413 per quarter ($1.63 annualized), it will provide approximately $9.7 million of internally generated capital on an annualized basis to provide increased liquidity, reduce leverage, invest in selected growth projects in the future, and strengthen the Company's balance sheet. This action should provide a sound catalyst to reducing our currently elevated cost of capital by de-levering and improving increased distribution coverage to our unitholders. We are confident these actions support the long-term interests of our unitholders, employees, and other stakeholders. We see encouraging signs with some new customers and we are focused on organic growth, and improved SWD asset utilization in an effort to improve cash flow that will in turn contribute to the improvement of all of our financial ratios. We continue to believe the fundamental demand for increased inspection and water disposal remains strong over the long-term, but the recovery has been slower than previously anticipated.

We continue to evaluate acquisition opportunities, and Holdings is prepared to assist the Partnership in acquiring attractive assets that may be larger than what the Partnership can independently acquire, with plans to offer those assets to the Partnership as drop-down opportunities over time. The Partnership is not currently evaluating any opportunities that would require material dilutive equity issuances. We hope to continue to grow our existing lines of business organically with minimal investment as our customers increase their spending and budgets coming out of the two-year oil and gas economic downturn.

Pipeline Inspection Services

Demand is once again growing for our pipeline inspection services, as we operate in a very large market with many customer prospects that we do not currently serve, and given that we provide federally-mandated essential services to protect our nation's critical energy infrastructure. The majority of our existing and potential customers are once again investing in their businesses following a difficult two-year downturn. We continue to focus on new lines of business to serve our existing customers. The majority of our clients are public investment-grade companies with long planning cycles that lead to healthy backlogs of new long-term projects, in addition to maintaining their existing pipeline networks that also require inspection and integrity services. The public utility company ("PUC") component of the industry, which brings natural gas to homes and businesses, remains an area with growth potential. We believe that with increasing regulatory requirements, and the aging pipeline infrastructure, that the PIS business is more insulated from changes in commodity prices in the near term than has been the case in the past. However, a prolonged depression in oil and natural gas prices could lead to a downturn in demand for our services as was the case over the last two years.

The downturn in energy prices required many of our customers that rely more heavily on commodity prices to focus on reducing their operating costs. Several clients have sought to reduce the rates paid to inspectors to reduce their inspection costs. We have recently renewed several sizable existing contracts and are bidding on several new contracts. However, we continue to see certain of our customers' projects slipping past original start dates as a result of permitting or other delays and were recently informed we were not a successful bidder on a request for proposal to perform inspection services for a customer that currently represents a large portion of the revenues of our Canadian subsidiary. Many of our customers are in the process of finalizing 2017 operating budgets (including inspection service costs) for submission to their board of directors. Many new projects and opportunities are awarded by our customers in the fourth quarter and the first quarter of the calendar year.

Integrity Services

Brown had a difficult year in 2016 and we were forced to implement aggressive measures to manage and reduce its cost structure. We have also recently hired some business development talent that will focus on the potential synergies that may develop between IS and other current customers of the Partnership, as well as the growth and nurture of its historical, ongoing business. Brown operated in 13 states during 2016, compared with almost 40 states that the TIR Entities (through our PIS segment) operated in throughout 2016. Brown's revenues declined during 2016, due in part to adverse market conditions and the fact that some construction companies performed their own hydrostatic testing work. There are indicators that energy companies are becoming more optimistic about market conditions, and if infrastructure companies become more active in developing new pipelines in the regions we serve, our IS segment could experience increased revenues in the future.

56

Water and Environmental Services

In our W&ES segment, the decline in the market price of crude oil that began in 2014 had an adverse impact on our revenues over the last two years. The resultant slowdown in exploration and production activity led to lower volumes, and the lower commodity prices led to lower revenues from sales of crude oil we recovered from the water we received. In addition, many of our E&P customers requested pricing concessions to help them cope with the lower commodity prices. In the majority of the basins in the country, new SWD facilities were developed to support the previous rig counts and activity levels prior to the sharp contraction in activity and commodity prices. These events have led to excess SWD facility supply relative to current demand in many locations, including the Bakken and the Permian that, in turn, has led to aggressive pricing. Rig activity has increased significantly in the Permian Basin and less so in the Bakken region since its low points in the first half of 2016. We have always focused on produced water vs. flowback water and therefore, we believe we have been less impacted than many competitors. During 2016, approximately 96% of our water volume was from produced water disposal. We are clearly being impacted by lower water volumes in the markets we serve, lower skim oil volumes as our flowback volumes decline, lower per-barrel water pricing and lower per-barrel oil pricing. In the second quarter of 2016, we took aggressive actions to reduce operating costs in an effort to offset the financial impact of continued depressed market volumes and prices. Additionally, we continue to focus on piped water opportunities to secure additional long-term volumes of produced water for the life of the oil and gas wells' production. Piped water continues to represent a growing percentage of our total volume. We also provide management services for an SWD facility in which we own a 25% interest.

We will continue to actively pursue the right acquisition opportunities with the same discipline that protected the Partnership during a heated market in 2014 and 2013 that drove up valuations to unsustainable levels. We also continue to evaluate and compete for some interesting opportunities for pipelines and SWD's directly with E&P companies seeking to monetize their midstream assets.

Despite the low oil and gas commodity prices of recent years, the Partnership has continued throughout 2016, and expects to sustain in 2017, positive cash flows. We continue to work collaboratively with our customers to help them address the volatility in commodity prices and their need to reduce operating expenses until prices stabilize. We also continue to carefully evaluate market pricing on a facility-by-facility basis. In January 2017, one of our facilities was struck by lightning. The downhole facilities were not damaged and we had insurance covering the surface facilities with a reasonable deductible. We do not carry business interruption insurance given its costs, waiting periods, and coverages. Within two weeks, the facility re-opened with temporary surface facilities. We have begun the process of designing and evaluating new surface facility configurations that will be implemented with insurance proceeds.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to select appropriate accounting policies and make estimates and assumptions that affect the reported amounts of assets, liabilities, revenue and expenses. See "*Note 2 — Summary of Significant Accounting Policies*" in the audited financial statements included in "*Item 8 — Financial Statements and Supplementary Data*" for descriptions of our major accounting policies and estimates. Certain of these accounting policies and estimates involve judgments and uncertainties to such an extent that there is a reasonable likelihood that materially different amounts would have been reported under different conditions, or if different assumptions had been used. The following discussions of critical accounting estimates, including any related discussion of contingencies, address all important accounting areas where the nature of accounting estimates or assumptions could be material due to the levels of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to change.

As a company with less than $1.0 billion in revenue during its last fiscal year, we qualify as an “emerging growth company” as defined in the Jumpstart Our Business Startups Act of 2012, or the JOBS Act. As an emerging growth company, we have elected to opt out of the exemption that allows emerging growth companies to extend the transition period for complying with new or revised financial accounting standards.

Impairments of Long-Lived Assets

We assess property, plant and equipment (“PP&E”) for possible impairment whenever events or changes in circumstances indicate that the carrying value of the assets may not be recoverable. Such indicators include, among others, the nature of the asset, the projected future economic benefit of the asset, changes in regulatory and political environments, and historical and future cash flow and profitability measurements. If the carrying value of an asset group exceeds the undiscounted cash flows estimated to be generated by the asset group, we recognize an impairment loss equal to the excess of carrying value of the asset group over its estimated fair value. Estimating the future cash flows and the fair value of an asset group involves management estimates on highly uncertain matters such as future commodity prices, the effects of inflation on operating expenses, and the outlook for national or regional market supply and demand for the services we provide.

For our W&ES segment, we evaluate property and equipment for impairment at the SWD facility level. Our estimates utilize judgments and assumptions such as undiscounted future cash flows, discounted future cash flows, estimated fair value of the asset group, and the current and future economic environment in which the asset is operated. Significant judgments and assumptions in these assessments include estimates of water disposal rates, disposal volumes, expected capital costs, oil and gas drilling and producing volumes in the markets served, risks associated with the different zones into which saltwater is disposed, and our estimate of an applicable discount rate commensurate with the risk of the underlying cash flow estimates. PP&E is not a significant component of our PIS or IS segments.

The W&ES segment has experienced increased competition in the regions in which we operate, which has resulted in declining volumes and increased pricing pressure. Steady and continued declines in oil prices have intensified competitive pressures and had a direct impact on our revenues. Many of our customers have announced significantly reduced drilling programs in the Bakken in particular. The decline in drilling has impacted the amount of flowback and produced water that we process and dispose, and has negatively impacted our pricing as our customers look for ways to reduce costs. In addition, as we process lower water volumes, in particular flowback water volumes directly attributable to drilling, we recover less skim oil.

During the years ended December 31, 2016, 2015 and 2014, we identified impairment indicators at certain of our SWD facilities and reviewed the associated property and equipment for impairment. We recognized impairment charges of $2.1 million, $6.6 million, and $12.8 million during the years ended December 31, 2016, 2015 and 2014, respectively, for assets that were determined to be impaired primarily driven by the dramatic decline in oil prices from over $100 / barrel to as low as $26 / barrel during the two-year downturn. These impairment reviews utilized inputs generally consistent with those described above. Judgments and assumptions are inherent in our estimate of future cash flows used to evaluate these assets. The use of alternate judgments and assumptions could result in the recognition of different levels of impairment charges in the Consolidated Financial Statements.

An estimate as to the sensitivity to earnings for these periods had we used other assumptions in our impairment reviews and impairment calculations is not practicable, given the number of assumptions involved in the estimates. Favorable changes to some assumptions might have obviated the need to impair any assets in these periods, whereas unfavorable changes might have caused an additional unknown number of other assets to become impaired. Additionally, further unfavorable changes in the future are reasonably possible, and therefore, it is possible that we may incur additional impairment charges in the future.

Business Combinations and Intangible Assets Including Goodwill

We account for acquisitions of businesses using the acquisition method of accounting. Accordingly, assets acquired and liabilities assumed are recorded at their estimated fair values at the acquisition date. The excess of purchase price over fair value of net assets acquired, including the amount assigned to identifiable intangible assets, is recorded as goodwill. The results of operations of acquired businesses are included in the Consolidated Financial Statements from the acquisition date.

Identifiable Intangible Assets

Our recorded identifiable intangible assets of $29.6 million and $32.5 million at December 31, 2016 and 2015, respectively, consist primarily of customer relationships and trademarks and trade names, amortized on a straight-line basis over estimated useful lives ranging from 5 – 20 years. Identifiable intangible assets with finite lives are amortized on a straight-line basis over their estimated useful lives, which is the period over which the asset is expected to contribute directly or indirectly to our future cash flows. We have no indefinite-lived intangibles other than goodwill. The determination of the fair value of the intangible assets and the estimated useful lives are based on an analysis of all pertinent factors including (1) the use of widely-accepted valuation approaches, such as the income approach, or the cost approach, (2) our expected use of the asset, (3) the expected useful life of related assets, (4) any legal, regulatory, or contractual provisions, including renewal or extension periods that would cause substantial costs or modifications to existing agreements, and (5) the effects of demand, competition, and other economic factors. Should any of the underlying assumptions indicate that the value of the intangible assets might be impaired, we may be required to reduce the carrying value and subsequent useful life of the asset. If the underlying assumptions governing the amortization of an intangible asset were later determined to have significantly changed, we may be required to adjust the amortization period of such asset to reflect any new estimate of its useful life. Any write-down of the value or unfavorable change in the useful life of an intangible asset would increase expense at that time. There were no impairments of identifiable intangible assets during the years ended December 31, 2016 or 2015.

58

Goodwill

At December 31, 2016 and 2015, the Partnership had $56.9 million and $65.3 million of goodwill, respectively. Goodwill is not amortized, but is subject to annual reviews on November 1 for impairment at a reporting unit level. The reporting units are determined primarily from the manner in which the business is managed and operated. A reporting unit is an operating segment or a component that is one level below an operating segment. We have determined that the PIS, IS, and W&ES segments are the appropriate reporting units for testing goodwill impairment.

To perform a goodwill impairment assessment, we first evaluate qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit exceeds its carrying value. If this assessment reveals that it is more likely than not that the carrying value of a reporting unit exceeds its fair value, we then compare the carrying value to the estimated fair market value of the reporting unit. If the carrying value exceeds the fair market value, we calculate the implied fair value of the goodwill and record an impairment loss, if necessary.

During second quarter of 2016, we identified potential indicators of impairment in our IS segment (Brown) that prompted us to perform a goodwill impairment assessment at that time. We estimated the fair value of the reporting unit using the income approach, under which we estimated the future cash flows to be generated by the business and discounted these cash flows using an assumed market interest rate. Significant inputs in the valuation included projections of future revenues, anticipated operating costs and appropriate discount rates. To estimate the fair value of the reporting unit and the implied fair value of goodwill, we assumed a tax structure where a buyer would obtain a step-up in the tax basis of the net assets acquired. Significant assumptions used in valuing the reporting unit included revenue growth rates ranging from 2% to 5% annually and a discount rate of 17.5%. In our assessment, the carrying value of the reporting unit, including goodwill, exceeded its estimated fair value. We then determined through our hypothetical acquisition analysis that the fair value of goodwill was impaired. As a result, we recorded an impairment loss of $8.4 million in our IS segment and reduced the value of recorded goodwill to $1.6 million in the second quarter of 2016.

During the fourth quarter 2016, we performed qualitative assessments on each of our reporting units to determine whether the fair values of the reporting units were more likely than not to be lower than their respective carrying values. Our evaluation consisted of assessing various qualitative factors, including projected future earnings, recent trends in earnings, market capitalization, current customer relationships and projects, and current economic conditions. In addition, as we continued to monitor the value of our IS segment (Brown) through the end of 2016, we performed additional quantitative calculations to determine if the IS goodwill may be impaired beyond that which was recorded in the second quarter of 2016. The qualitative and quantitative assessments in these reporting units indicated the fair values of the reporting units exceeded their carrying values and the goodwill of the reporting units was not impaired as of November 1 or December 31, 2016.

Our estimates of fair value are sensitive to changes in a number of variables, certain of which relate to broader macroeconomic conditions outside our control. As a result, actual performance could be different from these expectations and assumptions. This could be caused by events such as strategic decisions made in response to economic and competitive conditions and the impact of economic factors. In addition, some of the estimates and assumptions used in determining fair value of the reporting units are outside the control of management, including commodity prices, interest rates, cost of capital, and our credit ratings. The facilities of our W&ES reporting units are concentrated in two basins, and changes in oil and gas production in these two basins could have a significant impact on the profitability of this reporting unit. Our IS reporting unit experienced a downward trend in revenues during 2016. Our estimate of the fair value of the IS segment assumes that our revenues in future years will be higher than in 2016, which we believe to be a reasonable estimate based on historical results, management's plans for growing revenues of the segment, and management's economic outlook for the industry. While we believe we have made reasonable estimates and assumptions to estimate the fair values of our reporting units, it is reasonably possible that changes could occur that would require a goodwill impairment charge in the near future.

Depreciation Methods, Estimated Useful Lives of Property and Equipment

Depreciation expense represents the systematic write-off of the cost of property and equipment, net of residual or salvage value (if any), to the results of operations for the periods the assets are used. We depreciate our property and equipment using the straight-line method, which results in recording depreciation expense evenly over the estimated life of the individual assets. The estimate of depreciation expense requires us to make assumptions regarding the useful economic lives and residual values of our assets. At the time we acquired and placed our property and equipment in service, we developed assumptions about such lives and residual values that we believe are reasonable; however, circumstances may develop that could require us to change these assumptions in future periods, which would change our depreciation expense amounts prospectively. We currently use a life of 15 years for wells and related equipment, which include subsurface well completion and other improvements. We use a life of 9 years for tanks, plumbing and storage tanks and we generally use 5 years for our testing equipment and trailers. We use lives of 30 – 39 years for buildings. We believe that these lives represent the economic lives of the assets and that substantial capital expenditures would need to be incurred to extend their economic lives.

Consolidated Results of Operations – Cypress Energy Partners, L.P.

Factors Impacting Comparability

The historical results of operations for the periods presented may not be comparable, either to each other or to our future results of operations, for reasons described below:

The Partnership has recorded impairments of long-lived assets, intangible assets, and goodwill totaling $10.5 million, $6.6 million, and $32.5 million in 2016, 2015, and 2014, respectively.

Effective June 1, 2015, the Partnership acquired the remaining 49% interest in Cypress Energy Services, LLC ("CES LLC") previously held by a related party. As a result of this transaction, the 2014 Consolidated Financial Statements reflect a non-controlling interest of 49% of CES LLC from the IPO date through the end of the period, while the 2015 Consolidated Financial Statements reflect a 49% non-controlling interest from January 1, 2015 through May 31, 2015 related to CES LLC.

Effective May 1, 2015, the Partnership acquired a 51% controlling interest in Brown, a hydrostatic integrity services business. The Consolidated Financial Statements include Brown from this date forward with a 49% non-controlling interest.

At the closing of the IPO, we acquired a 50.1% interest in each of the TIR Entities with Holdings and certain affiliates continuing to hold the remaining 49.9% interest ("Retained Interest"). The non-controlling interest is reduced by certain interest charges as outlined in our amended and restated omnibus agreement. The contribution of interests in the TIR Entities to the Partnership has been treated as a reorganization of entities under common control. Accordingly, the results of operations and assets and liabilities of the TIR Entities are included in the historical financial information of the Partnership for periods from June 26, 2013, the date Holdings obtained control of the TIR Entities. Effective February 1, 2015, the Partnership acquired the remaining 49.9% non-controlling ownership interest of the TIR Entities from affiliated parties. Accordingly, the 2014 Consolidated Financial Statements reflect a non-controlling interest of 49.9% of the TIR Entities from the IPO date through the end of the period, while the Consolidated Financial Statements for 2015 reflect a 49.9% non-controlling interest from January 1, 2015 through January 31, 2015 related to the TIR Entities (less certain amounts charged directly to the non-controlling interests in both periods).

In the fourth quarter of 2014, the Partnership acquired an additional SWD facility in the Bakken shale region of North Dakota. Therefore, the results for the years ended December 31, 2015 and 2016 include the activity of this facility.

The year ended December 31, 2014 included non-recurring offering costs of $0.4 million and incurred in conjunction with our IPO. In addition, net income of the Partnership for the period from January 1, 2014 through January 20, 2014 (the period prior to our IPO) is reflected as *net income attributable to general partner* in the Consolidated Statements of Operations for the year ended December 31, 2014.

General and administrative expenses have increased as a result of operating as a publicly traded partnership. At the closing of the IPO, CEP LLC, the Partnership and other affiliates entered into an omnibus agreement with Holdings. Among other things, the agreement calls for an annual administrative fee to be paid by the Partnership in the amount of $4.0 million (adjusted annually as provided for in the omnibus agreement), payable in quarterly installments to Holdings, for providing the Partnership with certain overhead services, including executive management services by certain officers of our General Partner, compensation expense, for employees required to manage and operate our business, as well as the costs of operating a publicly traded partnership, including costs associated with SEC reporting requirements, tax return and Schedule K-1 preparation and distribution, independent registered public accounting firm fees, investor relations activities, and registrar and transfer agent fees. During the year ended December 31, 2016, Holdings provided sponsor support to the Partnership by waiving payment of the quarterly administrative fee. We reported the amount of the waived fee within *general and administrative expense* in our consolidated statement of operations and as an equity contribution in our consolidated statement of equity.

Interest expense will not be comparable between periods presented as a result of changes in the amount of debt outstanding and interest rates.

Consolidated Results of Operations

The following table compares the operating results of Cypress Energy Partners, L.P. for the years ended December 31:

	2016	2015 (a)	2014
	(in thousands)		
Revenues	$297,997	$371,191	$404,418
Costs of services	262,517	326,261	355,355
Gross margin	35,480	44,930	49,063
Operating costs and expense:			
General and administrative	21,853	23,795	21,321
Depreciation, amortization and accretion	4,861	5,427	6,345
Impairments	10,530	6,645	32,546

Operating income (loss)	(1,764)	9,063	(11,149)
Other income (expense):			
Interest expense, net	(6,559)	(5,656)	(3,208)
Offering costs	—	—	(446)
Gain on waiver of right of purchase and other, net	356	1,136	92
Net income (loss) before income tax expense	(7,967)	4,543	(14,711)
Income tax expense	1,195	452	468
Net income (loss)	(9,162)	4,091	(15,179)
Net income (loss) attributable to non-controlling interests	(4,499)	599	4,973
Net income (loss) attributable to partners / controlling interests	(4,663)	3,492	(20,152)
Net income (loss) attributable to general partner	(6,298)	(648)	149
Net income (loss) attributable to limited partners	$1,635	$4,140	$(20,301)

(a) Activity for the year ended December 31, 2015 includes the operations of Brown (IS segment) from the May 1, 2015 acquisition date through the end of the year.

See the detailed discussion of revenues, costs of services, gross margin, general and administrative expense and depreciation, amortization and accretion by reportable segment below. See also Note 14 to our Consolidated Financial Statements included in "*Item 8. – Financial Statement and Supplementary Data.*"

The following is a discussion of significant changes in the non-segment related corporate other income and expenses for the years ended December 31, 2016, 2015, and 2014.

Interest expense. Interest expense primarily consists of interest on borrowings under our Credit Agreement, as well as amortization of debt issuance costs and unused commitment fees. Interest expense increased in 2015 and 2016 primarily due to increased borrowings related to the acquisition of the remaining 49.9% interest in the TIR Entities and the acquisition of 51% of Brown. Average debt outstanding for the years ended December 31, 2016, 2015, and 2014 was $137.3 million, $129.9 million, and $72.5 million, respectively.

Offering costs. During the year ended December 31, 2014, we incurred offering costs of $0.4 million for professional services related to our IPO.

Gain on waiver of right of purchase and other, net. During 2015, the Partnership received $1.0 million for relinquishing its option to purchase certain assets from a related party. During 2016, the Partnership generated $0.3 million of income from its 25% interest in an SWD facility, which it is accounted for under the equity method.

Income tax expense. We qualify as a partnership for income tax purposes and therefore, generally do not pay income tax; instead, each owner reports his or her share of our income or loss on his or her individual tax return. Income tax expense relates to one taxable corporate subsidiary in the United States and one taxable corporate subsidiary in Canada in our PIS segment, as well as business activity, gross margin, and franchise taxes incurred in certain states. The increase in income tax expense from 2015 to 2016 results primarily from increased income generated by our TIR-PUC subsidiary that is taxed as a corporation for federal and state income tax purposes.

Net income attributable to noncontrolling interests. The net income attributable to non-controlling interests shown in our Consolidated Results of Operations reflects interests in the net income of consolidated entities that are not 100% owned by the Partnership. The decrease from 2014 to 2015 reflects the fact that we acquired the remaining 49.9% of the TIR Entities effective February 1, 2015. The 2015 amount includes one month of minority ownership of the TIR Entities and eight months of 49% of Brown Integrity, LLC earnings (acquired May 1, 2015). The net loss attributable to noncontrolling interests in 2016 relates primarily to Brown, which recorded an impairment loss of $8.4 million ($4.1 million of which was attributable to the noncontrolling interest).

Segment Operating Results

Pipeline Inspection Services (PIS)

The following table summarizes the operating results of our PIS segment for the years ended December 31, 2016 and 2015.

	Years Ended December 31,					
	2016	% of Revenue	2015	% of Revenue	Change	% Change
	(in thousands, except average revenue and inspector data)					
Revenue	$275,171		$341,929		$(66,758)	(19.5)%
Costs of services	247,214		309,584		(62,370)	(20.1)%
Gross margin	27,957	10.2 %	32,345	9.5 %	(4,388)	(13.6)%
General and administrative	12,521	4.6 %	16,672	4.9 %	(4,151)	(24.9)%
Depreciation, amortization and accretion	2,439	0.9 %	2,512	0.7 %	(73)	(2.9)%
Operating income	$12,997	4.7 %	$13,161	3.8 %	$(164)	(1.2)%
Operating Data						
Average number of inspectors	1,147		1,392		(245)	(17.6)%
Average revenue per inspector per week	$4,601		$4,711		$(110)	(2.3)%
Revenue variance due to number of inspectors					$(58,777)	
Revenue variance due to average revenue per inspector					$(7,981)	

62

Revenues. Revenues decreased $66.8 million from 2015 to 2016, primarily due to a decrease in the average number of inspectors engaged (a decline of 245 inspectors accounting for $58.8 million of the revenue decrease) and, to a lesser extent, a reduction in the average revenue billed for each inspector during the years presented. During 2016, we experienced delays and/or cancellations of significant projects within our customer base as a result of economic conditions in the energy industry. We continue to focus on areas of inspection less impacted by economic conditions, such as maintenance projects and projects associated with public utility companies to help mitigate the decline in revenues associated with new construction projects. The decline in average revenue per inspector is generally impacted by a change in customer mix as well as pricing concessions granted during the year. Fluctuations in the average revenue per inspector per year are not unexpected, given that we charge different rates for different types of inspectors and different types of inspection services.

Costs of services. Costs of services decreased $62.4 million from 2015 to 2016, which is directly attributable to the decline in revenues and average number of inspectors in the field.

Gross margin. Gross margin decreased $4.4 million from 2015 to 2016. The gross margin percentages from year-to-year improved slightly (10.2% in 2016 compared to 9.5% in 2015). The increase in gross margin percentage is attributable to the mix of services provided throughout the year.

General and administrative. General and administrative expenses decreased $4.2 million, due primarily to the fact that Holdings waived the omnibus fee in 2016 (in 2015, $2.8 million of the omnibus fee was reported within the PIS segment). Compensation expense was approximately $0.5 million lower in 2016 than in 2015, due to focused efforts to reduce overhead costs in response to the energy sector downturn.

Operating income. Operating income for the year ended December 31, 2016 decreased $0.2 million compared to the year ended December 31, 2015, primarily due to the gross margin decrease of $4.4 million, partially offset by a decrease in general and administrative expense of $4.2 million.

The following table summarizes the operating results of our PIS segment for the year ended December 31, 2015 and 2014.

	Years Ended December 31,					
	2015	% of Revenue	2014	% of Revenue	Change	% Change
	(in thousands, except average revenue and inspector data)					
Revenue	$341,929		$382,002		$(40,073)	(10.5)%

Costs of services	309,584		346,738		(37,154)	(10.7)%
Gross margin	32,345	9.5%	35,264	9.2%	(2,919)	(8.3)%
General and administrative	16,672	4.9%	17,734	4.6%	(1,062)	(6.0)%
Depreciation, amortization and accretion	2,512	0.7%	2,539	0.7%	(27)	(1.1)%
Operating income	$13,161	3.8%	$14,991	3.9%	$(1,830)	(12.2)%
Operating Data						
Average number of inspectors	1,392		1,535		(143)	(9.3)%
Average revenue per inspector per week	$4,711		$4,773		$(62)	(1.3)%
Revenue variance due to number of inspectors					$(35,126)	
Revenue variance due to average revenue per inspector					$(4,947)	

63

Revenues. Revenues decreased $40.1 million from 2014 to 2015 primarily due to a decrease in the average number of inspectors engaged (down 143 inspectors accounting for $35.1 million of the decrease from year-to-year) and, to a lesser extent, a reduction in the average revenue billed for each inspector during the years presented. The decline in the average number of inspectors deployed is directly attributable to the timing of projects for our customers. During 2015 we have seen delays and/or cancellations of significant projects within our customer base as a result of economic conditions in the energy industry. We continue to focus on areas of inspection less impacted by economic conditions, such as maintenance projects and projects associated with public utility companies to help mitigate the decline in revenues associated with new construction projects. The decline in average revenue per inspector is impacted by a change in customer mix as well as pricing concessions granted during the year. Fluctuations in the average revenue per inspector per year are not unexpected given our mix of customers as we have different billing rates and charges for different types of inspectors and different types of inspection services.

Costs of services. Costs of services decreased $37.2 million from 2014 to 2015, which is directly attributable to the decline in revenues and average number of inspectors in the field.

Gross margin. Gross margin decreased $2.9 million from 2014 to 2015. The gross margin percentages from year-to-year improved slightly (9.5% in 2015 and 9.2% in 2014). The increase in gross margin is attributable to the mix of services provided throughout the year.

General and administrative. General and administrative expenses decreased $1.1 million primarily due to focused efforts to reduce overhead costs, primarily non-billable payroll, in response to the energy sector downturn.

Operating income. Operating income for the year ended December 31, 2015 decreased $1.8 million compared to the year ended December 31, 2014, primarily due to the gross margin decrease of $2.9 million, offset by a decrease in general and administrative costs of $1.1 million.

Integrity Services (IS)

The following table summarizes the results of the IS segment for the year ended December 31, 2016 and the period from May 1, 2015 (date of acquisition) through December 31, 2015.

	Year Ended December 31,					
	2016	% of Revenue	2015 (a)	% of Revenue	Change	% Change
	(in thousands, except average revenue and inspector data)					
Revenue	$13,884		$14,614		$(730)	(5.0)%
Costs of services	11,542		10,398		1,144	11.0 %
Gross margin	2,342	16.9 %	4,216	28.8 %	(1,874)	(44.4)%
General and administrative	2,829	20.4 %	2,490	17.0 %	339	13.6 %
Depreciation, amortization and accretion	658	4.7 %	421	2.9 %	237	56.3 %
Impairments	8,411		—	0.0 %	8,411	
Operating income (loss)	$(9,556)	(68.8)%	$1,305	8.9 %	$(10,861)	(832.3)%
Operating Data						
Average number of field personnel	23		33		(10)	(30.3)%
Average revenue per field personnel per week	$11,577		$12,653		$(1,076)	(8.5)%
Revenue variance due to number of field personnel					$(6,020)	
Revenue variance due to average revenue per field personnel					$(1,846)	
Revenue variance due to period differences (see (a))					$7,136	

(a) We owned the IS segment for only eight months of the year ended December 31, 2015.

Revenue. Revenues decreased $0.7 million from 2015 to 2016. Revenues of the IS segment were adversely affected by a slowdown in new projects by its customers and by the loss of key business development employees. These decreases were partially offset by an additional four months of activity in 2016, as Brown was acquired May 1, 2015.

Costs of services. Costs of services increased $1.1 million from 2015 to 2016, as we owned Brown for the full year ended December 31, 2016, but for only eight months of the year ended December 31, 2015. The employees of the IS segment who perform work in the field are full-time employees, and therefore represent fixed costs (in contrast to the employees of the PIS segment who perform work in the field, most of whom only earn wages when they are performing work for a customer, and whose wages are therefore variable costs). In addition, increases in costs of services were partially offset by cost saving measures instituted during 2016, including the closing of an office and reductions in work force.

Gross margin. Gross margin decreased $1.9 million from 2015 to 2016. The decrease in gross margin was due to lower revenues. Because most of the employees of the IS segment are full time employees, cost of services from 2015 to 2016 did not decline commensurate with the decrease in revenues over the same period.

General and administrative. General and administrative expenses increased $0.3 million. This increase was primarily due to the fact that we owned our 51% interest in Brown for the full year ended December 31, 2016, but for only eight months of the year ended December 31, 2015. The resultant increase in general and administrative expense was partially offset by reductions in personnel that we initiated in response to the low-revenue environment.

Depreciation, amortization and accretion. Depreciation and amortization expense increased $0.2 million from 2015 to 2016. This increase was primarily due to the fact that we owned our 51% interest in Brown for the full year ended December 31, 2016, but for only eight months of the year ended December 31, 2015.

Impairments. During the year ended December 31, 2016, we recorded an impairment of $8.4 million to the goodwill of the IS segment.

Operating income (loss). Operating income for the year ended December 31, 2016 decreased $10.9 million compared to the year ended December 31, 2015, primarily due to the gross margin decrease of $1.9 million and to the goodwill impairment charge of $8.4 million.

Water and Environmental Services (W&ES)

The following table summarizes the operating results of our W&ES segment for the years ended December 31, 2016 and 2015.

	Year Ended December 31,					
	2016	% of Revenue	2015	% of Revenue	Change	% Change
	(in thousands, except per barrel data)					
Revenue	$8,942		$14,648		$(5,706)	(39.0)%
Costs of services	3,761		6,279		(2,518)	(40.1)%
Gross margin	5,181	57.9 %	8,369	57.1 %	(3,188)	(38.1)%
General and administrative	1,866	20.9 %	3,351	22.9 %	(1,485)	(44.3)%
Depreciation, amortization and accretion	1,764	19.7 %	2,494	17.0 %	(730)	(29.3)%
Impairments	2,119	23.7 %	6,645	45.4 %	(4,526)	(68.1)%
Operating loss	$(568)	(6.4)%	$(4,121)	(28.1)%	$3,553	(86.2)%
Operating Data						
Total barrels of saltwater disposed	13,307		18,864		(5,557)	(29.5)%
Average revenue per barrel disposed (a)	$0.67		$0.78		$(0.10)	(13.5)%
Revenue variance due to barrels disposed					$(4,315)	
Revenue variance due to revenue per barrel					$(1,391)	

(a) Average revenue per barrel disposed is calculated by dividing revenues (which includes disposal revenues, residual oil sales and management fees) by the total barrels of saltwater disposed.

Revenue. The decrease of $5.7 million in revenues from 2015 to 2016 is primarily due to a 29.5% decrease in the volume of produced and flowback saltwater disposed (accounting for $4.3 million of the decrease in revenues) and to a decrease in the average revenue per barrel disposed (accounting for $1.4 million of the decrease in revenues). The decrease in volumes was due primarily to reduced exploration and production activity in the areas where we operate, as a result of low commodity prices. The decrease in average revenue per barrel processed was due to pricing pressures resulting from competition, the fact that recovered oil volumes were lower as a percentage of water volumes processed, and to lower selling prices for crude oil we recovered. Oil revenue represented 6% of total revenue in 2016, compared to 8% in 2015.

Costs of services. Costs of services decreased by $2.5 million from 2015 to 2016, due primarily to a $1.3 million decrease in employee compensation expense and to a $0.9 million decrease in repair and maintenance expense. The decrease in employee compensation expense was attributable to cost reduction measures that we implemented in mid-2016 in response to adverse conditions in the exploration and production market. These measures included the temporary suspension of activity at two of our facilities and investments in automation at other facilities. Repair and maintenance expenses fluctuate based on a variety of factors. Other decreases in cost of sales from 2015 to 2016 included a decrease of $0.2 million in utility expense and a decrease of $0.1 million in oil disposal costs, both of which are attributable to lower volumes.

Gross margin. Gross margin decreased by $3.2 million from 2015 to 2016, due to a decrease in revenues of $5.7 million, partially offset by a decrease in cost of services of $2.5 million.

General and administrative expense. General and administrative expenses decreased by $1.5 million from 2015 to 2016, due primarily to the fact that Holdings waived the omnibus fee in 2016 (the portion of the omnibus fee allocable to the WE&S segment was $1.2 million in 2015). In addition, royalty expenses were $0.2 million lower in 2016 than in 2015, as a result of lower revenues.

Depreciation, amortization and accretion. Depreciation expenses decreased from 2015 to 2016 primarily due to the prior impairment of equipment at various SWD facilities. As equipment is impaired, there is less asset basis to depreciate.

Impairments. As a result of the decline in commodity prices and a decline in drilling activity around some of our facilities, we recorded impairment charges during the years ended December 31, 2016 and 2015 to property, plant and equipment of $2.1 million and $6.6 million, respectively.

Operating loss. Operating loss declined $3.6 million from 2015 to 2016. The decrease in gross margin from 2015 to 2016 was more than offset by lower general and administrative expenses and impairment charges.

67

The following table summarizes the operating results of our W&ES segment for the years ended December 31, 2015 and 2014.

	Year Ended December 31,					
	2015	% of Revenue	2014	% of Revenue	Change	% Change
	(in thousands, except per barrel data)					
Revenue	$14,648		$22,416		$(7,768)	(34.7)%
Costs of services	6,279		8,617		(2,338)	(27.1)%
Gross margin	8,369	57.1%	13,799	61.6%	(5,430)	(39.4)%
General and administrative	3,351	22.9%	3,587	16.0%	(236)	(6.6)%
Depreciation, amortization and accretion	2,494	17.0%	3,806	17.0%	(1,312)	(34.5)%
Impairments	6,645	45.4%	32,546	145.2%	(25,901)	(79.6)%
Operating (loss)	$(4,121)	(28.1)%	$(26,140)	(116.6)%	$22,019	(84.2)%
Operating Data						
Total barrels of saltwater disposed	18,864		19,066		(202)	(1.1)%
Average revenue per barrel disposed (a)	$0.78		$1.18		$(0.40)	(34.0)%
Revenue variance due to barrels disposed					$(237)	
Revenue variance due to revenue per barrel					$(7,531)	

(a) Average revenue per barrel disposed is calculated by dividing revenues (which includes disposal revenues, residual oil sales and management fees) by the total barrels of saltwater disposed.

Revenue. The decrease of $7.8 million in revenues is primarily due to a 34.0% reduction in the overall average disposal price per barrel from 2014 to 2015 (accounting for $7.5 million of the total $7.8 million decrease year-to-year). The average revenue per barrel disposed declined from $1.18 in 2014 to $0.78 in 2015. The primary contributor to the decline in the average revenue per barrel is the decline in oil revenues. In 2014, oil revenue represented 22% of total revenue compared to 8% in 2015. The decline in oil revenue is attributable to the decline in oil prices, as well as the volume of oil recovered through our skim oil recovery process. The decline in oil recovered is associated with decreased drilling in the areas in which we operate. Drilling activities generate flowback water which is typically higher in oil content. In addition to the decline in oil revenues, the segment has experienced a corresponding decline in flowback water disposal revenues. The decline in the volume flowback water disposed was largely offset by an increase in production water volumes disposed, primarily attributable to the acquisition of the Mork facility effective December 1, 2014. However, because flowback disposal pricing is higher than production water disposal pricing, we experienced an overall decline in revenue attributable to the shift in volumes between flowback disposal and production disposal.

Costs of services. Costs of services decreased from 2014 to 2015 primarily due to lower repairs and maintenance expenses, lower labor related costs and lower oil disposal costs. Repairs and maintenance expenses can fluctuate period to period depending on the nature and timing of required repairs and the type and volume of water disposed at each facility. The decrease in repairs and maintenance is attributable to lower water volumes, in particular flowback volumes associated with drilling activity, as well as the occurrence of some large expenditures in 2014. In response to lower volumes and prices, we have altered labor schedules and hours of operation across our facilities which has resulted in lower total labor costs. In addition to the schedule adjustments, we are no longer incurring labor costs for two facilities that we previously managed. The lower oil disposal costs are directly attributable to the decline in oil barrels sold.

Gross margin. Gross margin decreased as a result of the reduced revenues, offset by a reduction in cost of services. The decrease in gross margin percentage is mainly caused by lower water disposal revenues, offset in part, by lower costs of services from 2014 to 2015. The decrease in the gross margin percentage is also attributable to the loss of management revenue related to two management contracts terminated by the owners in the first half of 2015.

General and administrative expense. The reduction in general and administrative expenses of $0.2 million is mainly attributable to general cost cutting measures instituted by the Partnership.

Depreciation, amortization and accretion. Depreciation expense decreased from period to period primarily due to the prior impairment of equipment at various SWD facilities. As equipment is impaired, there is less asset basis to depreciate.

Impairments. As a result of the decline in commodity prices and a decline in drilling activity around some of our facilities, we recorded impairment charges during the years ended December 31, 2015 and 2014 associated with our W&ES segment totaling $6.6 million and $32.5 million, respectively. The impairment charges consist of impairments of long lived assets in the years ended December 31, 2015 and 2014 totaling $6.6 million and $12.8 million, respectively, and goodwill impairments in the year ended December 31, 2014 totaling $19.8 million.

Operating loss. Operating loss declined $22.0 million from 2014 to 2015 primarily due to a decrease in impairment charges totaling $25.9 million. Excluding the impairment charges, segment operating loss increased $3.9 million primarily attributable to the decline in the gross margin discussed above, offset in part, by lower depreciation, amortization and accretion deductions due to the impairment write down to the basis of depreciable assets in 2014.

Liquidity and Capital Resources

We anticipate making growth capital expenditures in the future, including acquiring new businesses that may include pipeline inspection companies and SWD facilities or expanding our existing assets and offerings in our current operations. In addition, the working capital needs of the PIS segment are substantial, driven by payroll and per diem expenses paid to our inspectors on a weekly basis. Please read *"Risk Factors — Risks Related to Our Business — The working capital needs of the PIS segment are substantial"*, which could require us to seek additional financing that we may not be able to obtain on satisfactory terms, or at all. Consequently, our ability to develop and maintain sources of funds to meet our capital requirements is critical to our ability to meet our growth objectives. We expect that our future growth capital expenditures will be funded by borrowings under our Credit Agreement and the issuance of debt and equity securities. However, we may not be able to raise additional funds on desired or favorable terms or at all.

At December 31, 2016, our sources of liquidity included:

$26.7 million in cash on the balance sheet at December 31, 2016 (inclusive of cash attributable to the non-controlling interest holders);

borrowings under our Credit Agreement under which we had $63.1 million available for borrowings at December 31, 2016 that are limited by certain borrowing base limitations and financial covenant ratios as outlined in the Credit Agreement; and

issuance of equity and/or debt securities. The Partnership filed a Securities Registration Statement with the Securities and Exchange Commission on June 8, 2015 to register $1.0 billion in securities, which the Partnership may issue in any combination of equity or debt securities from time to time in one or more offerings.

Currently, we believe that the cash generated from our current sources of liquidity will be sufficient to allow us to meet working capital requirements and capital expenditures for the foreseeable future.

Our board now believes it is prudent and responsible to make the difficult decision to reduce our quarterly distribution for the first time since our initial public offering in January of 2014. Absent an acquisition in the near future, we currently anticipate reducing the current distribution by approximately 50%. The exact amount, record date, and payment date of the distribution will be determined by the Board after review of first quarter results. If this distribution level is maintained throughout fiscal 2017, compared to the previous distribution level of $0.406413 per quarter ($1.63 annualized), it will provide approximately $9.7 million of internally generated capital on an annualized basis to provide increased liquidity, reduce leverage, invest in selected growth projects in the future, and strengthen the Company's balance sheet. This action should provide a sound catalyst to reducing our currently elevated cost of capital by de-levering and improving increased distribution coverage to our unitholders. We are confident these actions support the long-term interests of our unitholders, employees, and other stakeholders. We see encouraging signs with some new customers and we are focused on organic growth, and improved SWD asset utilization in an effort to improve cash flow that will in turn contribute to the improvement of all of our financial ratios. We continue to believe the fundamental demand for increased inspection and water disposal remains strong over the long-term, but the recovery has been slower than previously anticipated.

Cash Flows

The following table sets forth a summary of the net cash provided by (used in) operating, investing and financing activities for the periods identified. The cash flows include activity of the IS segment since the acquisition of Brown on May 1, 2015 and therefore, may not be comparable from period to period.

	Year Ended December 31,		
	2016	2015 (in thousands)	2014
Net cash provided by operating activities	$24,819	$ 26,921	$13,016
Net cash used in investing activities	(1,330)	(64,879)	(2,286)
Net cash provided by (used in) financing activities	(21,289)	42,501	(16,030)
Effect of exchange rates on cash	343	(1,150)	(633)
Net increase (decrease) in cash and cash equivalents	$2,543	$ 3,393	$(5,933)

Operating activities. Net operating cash inflows for the year ended December 31, 2016 were $24.8 million, consisting of a net loss of $9.2 million plus non-cash expenses of $21.6 million and net changes in working capital of $12.4 million. Non-cash expenses included depreciation and impairment expense, among others. Non-cash expenses also included expenses attributable to the Partnership that were paid by Holdings and recorded as an equity contribution in the Partnership’s financial statements. The net change in working capital included a net decrease of $9.9 million in accounts receivable over the course of 2016. Net operating cash for the year ended December 31, 2015 included $4.1 million of net income, $15.0 million of non-cash expenses, and $7.9 million of net changes in working capital. Net operating cash inflows for the year ended December 31, 2014 were $13.0 million, consisting of a net loss of $15.2 million plus non-cash expenses of $41.1 million, partially offset by a net change in working capital of $12.9 million. Operating cash outflows during 2014 included the payment of $15.0 million of income taxes related to the conversion of the U.S. TIR Entities from taxable entities to pass-through entities for income tax purposes.

Investing activities. Cash used in investing activities consists primarily of acquisitions and capital expenditures. In 2015, we acquired the remainder of the TIR Entities for $52.6 million and we acquired a 51% interest in Brown for $10.4 million. In 2014 we acquired an SWD facility for $1.8 million. Capital expenditures were $1.4 million, $1.9 million, and $0.5 million during the years ended December 31, 2016, 2015, and 2014, respectively. Capital expenditures during 2016 consisted primarily of equipment purchases, much of which was in support of increasing revenues in TIR’s non-destructive examination business.

Financing activities. Financing cash outflows for the year ended December 31, 2016 included $19.7 million of distributions to owners and $4.0 million of repayments on the revolving credit facility. Financing cash inflows for the year ended December 31, 2016 included $2.5 million of contributions from Holdings to support the Partnership. Financing cash inflows during the year ended December 31, 2015 included net borrowings of $63.3 million on the revolving credit facility, in order to fund acquisitions. Financing cash outflows for the year ended December 31, 2015 included $20.8 million of distributions to owners. Financing cash outflows for the year ended December 31, 2014 included $17.7 million of distributions to owners, $0.9 million of debt issuance costs related to the revolving credit facility, and $0.3 million of offering costs related to the Partnership’s IPO. Financing cash inflows for the year ended December 31, 2014 included net borrowings of $2.6 million on the revolving credit facility and $0.5 million of contributions from parent entities.

Working Capital

Our working capital was $54.3 million at December 31, 2016, compared to $64.2 million at December 31, 2015, a reduction of approximately 15% compared to a reduction in revenue of approximately 20%. Our PIS and IS segments have substantial working capital needs as they generally pay their inspectors and field personnel on a weekly basis, but typically receive payment from their customers 45 to 90 days after the services have been performed. We utilize borrowings under our Credit Agreement to fund the working capital needs of these segments. These borrowings reduce the amount of credit available for other uses, such as acquisitions and growth projects, and increases interest expense, thereby reducing cash flow. Please read *"Risk Factors — Risks Related to Our Business — The working capital needs of the PIS segment are substantial, which could require us to seek additional financing that we may not be able to obtain on satisfactory terms, or at all."*

Capital Requirements

W&ES has capital needs requiring investment for the maintenance of existing SWD facilities and the acquisition or construction and development of new SWD facilities. Our partnership agreement will require that we categorize our capital expenditures as either maintenance capital expenditures or expansion capital expenditures.

Maintenance capital expenditures are those cash expenditures that will enable us to maintain our operating capacity or operating income over the long-term. Maintenance capital expenditures include tankage, workovers, pipelines, pumps and other improvement of existing capital assets, including the construction or development of new capital assets to replace our existing saltwater disposal systems as they become obsolete. Other examples of maintenance capital expenditures are expenditures to repair, refurbish and replace tubing and packers on the SWD well itself to maintain equipment reliability, integrity and safety, as well as to address environmental laws and regulations. Maintenance capital expenditures for the years ended December 31, 2016 and 2015 were $0.5 million and $0.5 million, respectively.

Expansion capital expenditures are those capital expenditures that we expect will increase our operating capacity or operating income over the long-term. Expansion capital expenditures include the acquisition of assets or businesses from Holdings or third-parties and the construction or development of additional saltwater disposal capacity or efficiencies, to the extent such expenditures are expected to expand our long-term operating capacity or operating income. Expansion capital expenditures include interest payments (and related fees) on debt incurred to finance all or a portion of expansion capital expenditures in respect of the period from the date that we enter into a binding obligation to commence the construction, development, replacement, improvement, automation or expansion of a capital asset and ending on the earlier to occur of the date that such capital improvement commences commercial service and the date that such capital improvement is abandoned or disposed of. Expansion capital expenditures for the years ended December 31, 2016 and 2015 were $0.8 million and $1.2 million, respectively.

Our future expansion capital expenditures may vary significantly from period to period based on the investment opportunities available to us. We expect to fund future capital expenditures from cash flow generated from our operations, borrowings under our Credit Agreement, the issuance of additional partnership units or debt offerings.

Our Credit Agreement

The Partnership is party to a credit agreement (as amended, the "Credit Agreement") that provides up to $200.0 million in borrowing capacity, subject to certain limitations. The Credit Agreement includes a working capital revolving credit facility ("Working Capital Facility") which provides up to $75.0 million in borrowing capacity to fund working capital needs and an acquisition revolving credit facility ("Acquisition Facility") which provides up to $125.0 million in borrowing capacity to fund acquisitions and expansion projects if lenders agree to increase their commitments. In addition, the Credit Agreement contains an accordion feature that allows us to increase the availability under the facilities by an additional $125.0 million. The Credit Agreement matures on December 24, 2018.

Outstanding borrowings at December 31, 2016 and 2015 under the Credit Agreement were as follows:

	December 31,	
	2016	2015
	(in thousands)	
Working capital facility	$48,000	$52,000
Acquisition facility	88,900	88,900
Total borrowings	136,900	140,900
Debt issuance costs	1,201	1,771
Long-term debt	$135,699	$139,129

The carrying value of the partnership's long-term debt approximates fair value, as the borrowings under the Credit Agreement are considered to be priced at market for debt instruments having similar terms and conditions (Level 2 of the fair value hierarchy).

Borrowings under the Working Capital Facility are limited by a monthly borrowing base calculation as defined in the Credit Agreement. If, at any time, outstanding borrowings under the Working Capital Facility exceed the Partnership's calculated borrowing base, a principal payment in the amount of the excess is due upon submission of the borrowing base calculation. Available borrowings under the Acquisition Facility may be limited by certain financial covenant ratios as defined in the Credit Agreement. The obligations under our Credit Agreement are secured by a first priority lien on substantially all assets of the Partnership.

All borrowings under the Credit Agreement bear interest, at our option, on a leveraged based grid pricing at (i) a base rate plus a margin of 1.25% to 2.75% per annum ("Base Rate Borrowing") or (ii) an adjusted LIBOR rate plus a margin of 2.25% to 3.75% per annum ("LIBOR Borrowings"). The applicable margin is determined based on the leverage ratio of the Partnership, as defined in the Credit Agreement. Generally, the interest rate on our Credit Agreement borrowings ranged between 3.54% and 4.52% for the year ended December 31, 2016, 2.68% and 4.17% for the year ended December 31, 2015 and 2.65% and 3.50% for the year ended December 31, 2014. Interest on Base Rate Borrowings is payable monthly. Interest on LIBOR Borrowings is paid upon maturity of the underlying LIBOR contract, but no less often than quarterly. Commitment fees are charged at a rate of 0.50% on any unused credit and are payable quarterly.

Our Credit Agreement contains various customary affirmative and negative covenants and restrictive provisions. Our Credit Agreement also requires maintenance of certain financial covenants, including a combined total adjusted leverage ratio (as defined in our Credit Agreement) of not more than 4.0 to 1.0 and an interest coverage ratio (as defined in our Credit Agreement) of not less than 3.0 to 1.0. At December 31, 2016, our combined total adjusted leverage ratio was 3.41 to 1.0 and our interest coverage ratio was 3.78 to 1.0, pursuant to the Credit Agreement. Upon the occurrence and during the continuation of an event of default, subject to the terms and conditions of our Credit Agreement, the lenders may declare any outstanding principal of our Credit Agreement debt, together with accrued and unpaid interest, to be immediately due and payable and may exercise the other remedies set forth or referred to in our Credit Agreement. We were in compliance with all debt covenants as of December 31, 2016 and expect to remain in compliance with all of our financial debt covenants for the next twelve months following the filing of this Form 10-K. Working capital borrowings, which are fully secured by the Partnership's net working capital, are subject to a monthly borrowing base and are excluded from the Partnership's debt compliance ratios.

In addition, our Credit Agreement restricts our ability to make distributions on, or redeem or repurchase, our equity interests. However, we may make distributions of available cash so long as, both at the time of the distribution and after giving effect to the distribution, no default exists under our Credit Agreement, the borrowers and the guarantors are in compliance with the financial covenants, the borrowing base (which includes 100% of cash on hand) exceeds the amount of outstanding credit extensions under the Working Capital Facilities by at least $5.0 million, and at least $5.0 million in lender commitments are available to be drawn under the Working Capital Facility.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements.

Contractual Obligations

A summary of the Partnership's contractual obligations and other commitments as of December 31, 2016 is shown in the table below.

	Total	Less than 1 Year	1 - 3 Years	3 - 5 Years	More than 5 Years
Long-term debt	$136,900	$—	$136,900	$ —	$ —
Lease obligations	1,598	865	176	50	507
Total	$138,498	$865	$137,076	$ 50	$ 507

71

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to market risk, including the effects of adverse changes in commodity prices and interest rates as described below.

The primary objective of the following information is to provide forward-looking quantitative and qualitative information, about our potential exposure to market risks. The term “market risk” refers to the risk of loss arising from adverse changes in oil, natural gas, and NGL prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. None of our market risk sensitive instruments were entered into for speculative trading purposes.

Commodity Price Risk

We are exposed to the impact of market fluctuations in the prices of crude oil in W&ES. Both our profitability and our cash flow are affected by volatility in the prices of these commodities. Crude oil prices are impacted by changes in the supply and demand for crude oil, as well as market uncertainty. For a discussion of the volatility of crude oil prices, please read “*Risk Factors*.” Adverse effects on our cash flow from reductions in crude oil prices could adversely affect our ability to make cash distributions to unitholders. We do not hedge our exposure to crude oil prices.

Less than 0.2% of our consolidated revenues in 2016 were derived from sales of commodities. A hypothetical change in commodity prices of 10% would result in an increase or decrease of our revenues derived from sales of commodities of approximately $0.1 million. Increases or decreases in commodity prices can also result in changes in demand for our wastewater disposal and pipeline inspection and integrity services resulting in an increase or decrease of our revenues and gross margins.

Interest Rate Risk

We currently have exposure to changes in interest rates on our indebtedness associated with our Credit Agreement. We may implement swap or cap structures to mitigate our exposure to interest rate risk; however, we do not currently have any swaps or cap structures in place. Accordingly, as of December 31, 2016, our exposure consists of floating interest rate fluctuations on our outstanding indebtedness under our Credit Agreement of $136.9 million. A hypothetical change in interest rates of 1.0% would result in an increase or decrease of our annual interest expense of approximately $1.4 million.

The credit markets have recently experienced historical lows in interest rates. As the overall economy strengthens, it is possible that monetary policy will continue to tighten further, resulting in higher interest rates to counter possible inflation as has been evidenced by recent interest rate hikes by the Federal Reserve. Interest rates on floating rate credit facilities and future debt offerings could be higher than current levels, causing our financing costs to increase accordingly.

Counterparty and Customer 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 amounts they owe to us, this could have a material adverse effect on our business, financial condition, results of operations or cash flows. In addition, any downgrade of our customers' receivables from investment grade (defined as BBB- or higher by S&P or Baa3 or higher by Moody's) could reduce our borrowing capacity or potentially place the Partnership at risk of default on the working capital revolving credit facility of our Credit Agreement. The result of downgrades of our customers' receivables could have a material adverse effect on our business, financial condition, results of operations, or cash flows. Throughout 2016, over 89% of our revenues were earned from customers that were rated investment grade.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The following information is included in this Item 8:

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Cypress Energy Partners, GP, LLC, as

General Partner of Cypress Energy Partners, L.P.,

and the Limited Partners of Cypress Energy Partners, L.P.

We have audited the accompanying consolidated balance sheets of Cypress Energy Partners, L.P. (the "Partnership") as of December 31, 2016 and 2015, and the related consolidated statements of operations, comprehensive income (loss), owners' equity and cash flows for each of the three years in the period ended December 31, 2016. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Partnership's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Partnership's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Cypress Energy Partners, L.P. at December 31, 2016 and 2015, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2016, in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP

Tulsa, Oklahoma

March 15, 2017

CYPRESS ENERGY PARTNERS, L.P.
Consolidated Balance Sheets
As of December 31, 2016 and 2015
(in thousands, except unit data)

	December 31, 2016	December 31, 2015 (as adjusted)
ASSETS		
Current assets:		
Cash and cash equivalents	$26,693	$24,150
Trade accounts receivable, net	38,482	48,265
Prepaid expenses and other	1,042	2,329
Total current assets	66,217	74,744
Property and equipment:		
Property and equipment, at cost	22,459	23,706
Less: Accumulated depreciation	7,840	5,369
Total property and equipment, net	14,619	18,337
Intangible assets, net	29,624	32,486
Goodwill	56,903	65,273
Other assets	149	42
Total assets	$167,512	$190,882
LIABILITIES AND OWNERS' EQUITY		
Current liabilities:		
Accounts payable	$1,690	$2,205
Accounts payable - affiliates	1,638	913
Accrued payroll and other	7,585	7,095
Income taxes payable	1,011	350
Total current liabilities	11,924	10,563
Long-term debt	135,699	139,129
Deferred tax liabilities	362	371
Asset retirement obligations	139	117
Total liabilities	148,124	150,180
Commitments and contingencies - Note 13		
Owners' equity:		
Partners' capital:		
Common units (5,945,348 and 5,920,467 units outstanding at December 31, 2016 and 2015, respectively)	(7,722)	253
Subordinated units (5,913,000 units outstanding at December 31, 2016 and 2015)	50,474	59,143
General partner	(25,876)	(25,876)
Accumulated other comprehensive loss	(2,538)	(2,791)
Total partners' capital	14,338	30,729
Non-controlling interests	5,050	9,973

Total owners' equity	19,388	40,702
Total liabilities and owners' equity	$167,512	$190,882

See accompanying notes.

CYPRESS ENERGY PARTNERS, L.P.
Consolidated Statements of Operations
For the Years Ended December 31, 2016, 2015 and 2014
(in thousands, except unit and per unit data)

	2016	2015	2014
Revenues	$297,997	$371,191	$404,418
Costs of services	262,517	326,261	355,355
Gross margin	35,480	44,930	49,063
Operating costs and expense:			
General and administrative	21,853	23,795	21,321
Depreciation, amortization and accretion	4,861	5,427	6,345
Impairments	10,530	6,645	32,546
Operating income (loss)	(1,764)	9,063	(11,149)
Other income (expense):			
Interest expense, net	(6,559)	(5,656)	(3,208)
Offering costs	—	—	(446)
Gain on waiver of right of purchase and other, net	356	1,136	92
Net income (loss) before income tax expense	(7,967)	4,543	(14,711)
Income tax expense	1,195	452	468
Net income (loss)	(9,162)	4,091	(15,179)
Net income (loss) attributable to non-controlling interests	(4,499)	599	4,973
Net income (loss) attributable to partners / controlling interests	(4,663)	3,492	(20,152)
Net income (loss) attributable to general partner	(6,298)	(648)	149
Net income (loss) attributable to limited partners	$1,635	$4,140	$(20,301)
Net income (loss) attributable to limited partners allocated to:			
Common unitholders	$819	$2,071	$(10,150)
Subordinated unitholders	816	2,069	(10,151)
	$1,635	$4,140	$(20,301)
Net income (loss) per common limited partner unit:			
Basic	$0.14	$0.35	$(1.72)
Diluted	$0.13	$0.35	$(1.72)
Net income (loss) per subordinated limited partner unit - basic and diluted	$0.14	$0.35	$(1.72)
Weighted average common limited partner units outstanding:			
Basic	5,934,226	5,918,608	5,913,000
Diluted	6,090,103	5,918,608	5,913,000
Weighted average subordinated limited partner units outstanding - basic and diluted	5,913,000	5,913,000	5,913,000

See accompanying notes.

CYPRESS ENERGY PARTNERS, L.P.
Consolidated Statements of Comprehensive Income (Loss)
For the Years Ended December 31, 2016, 2015 and 2014
(in thousands)

	2016	2015	2014
Net income (loss)	$(9,162)	$4,091	$(15,179)
Other comprehensive income (loss) - foreign currency translation	253	(1,742)	(937)
Comprehensive income (loss)	$(8,909)	$2,349	$(16,116)
Comprehensive income (loss) attributable to non-controlling interests	(4,499)	142	4,658
Comprehensive income (loss) attributable to general partner	(6,298)	(648)	149
Comprehensive income (loss) attributable to limited partners	$1,888	$2,855	$(20,923)

See accompanying notes.

CYPRESS ENERGY PARTNERS, L.P.
Consolidated Statement of Owners' Equity
For the Years Ended December 31, 2016, 2015 and 2014
(in thousands)

	Parent Net Investment Attributable to Controlling Interest	**Parent Net** Investment Attributable to Non-Controlling Interest	Partners' Capital **General Partner**	**Common Units**	**Subordinated Units**	**Accumulated Other Comprehensive Loss**	**Non-controlling Interests**	**Total Owners' Equity**
Owners' equity at December 31, 2013	$ 130,012	$ 719	$ 4,816	$ —	$ —	$ —	$ —	$ 4,816
Net income (loss) for the period January 1, 2014 through January 20, 2014	1,092	(6)	(446)	—	—	—	—	(446
Foreign currency translation adjustment for the period January 1, 2014 through January 20, 2014	(304)	—	—	—	—	—	—	—
Net distributions to members	(168)	—	—	—	—	—	—	—
Contributions attributable to General Partner	—	—	979	—	—	—	—	979
Contributions of Predecessor and 50.1% of TIR Entities in exchange for units	(130,632)	(713)	—	22,491	82,470	(208)	26,592	131,34
Proceeds from initial public offering, net of	—	—	(2,853)	80,213	—	—	—	77,360

costs								
Distribution of initial public offering proceeds to Cypress Energy Holdings, LLC	—	—	—	(80,213)	—	—	—	(80,21
Distributions to limited partners	—	—	—	(6,532)	(6,532)	—	—	(13,06
Distributions to non-controlling interests	—	—	—	—	—	—	(4,683)	(4,683
Equity-based compensation	—	—	—	476	309	—	—	785
Net income (loss) for the period January 21, 2014 through December 31, 2014	—	—	(497)	(10,150)	(10,151)	—	4,979	(15,81
Foreign currency translation adjustment for the period January 21, 2014 through December 31, 2014	—	—	—	—	—	(317)	(315)	(632
Owners' equity at December 31, 2014	—	—	1,999	6,285	66,096	(525)	26,573	100,42
Net income (loss)	—	—	(648)	2,071	2,069	—	599	4,091
Foreign currency translation adjustment	—	—	—	—	—	(1,285)	(457)	(1,742
Acquisition of 49.9% interest in the TIR Entities (Note 3)	—	—	(27,729)	—	—	(981)	(23,878)	(52,58
Acquisition of 51% interest in Brown Integrity, LLC (Note 3)	—	—	—	—	—	—	9,497	9,497

Acquisition of 49% interest in Cypress Energy Services, LLC (Note 12)	—	—	—	470	470	—	(940)	—
Contributions attributable to General Partner	—	—	648	—	—	—	—	648
Distributions to limited partners	—	—	—	(9,620)	(9,612)	—	—	(19,23
Distributions to non-controlling interests	—	—	(146)	—	—	—	(1,421)	(1,567
Equity-based compensation	—	—	—	1,047	120	—	—	1,167
Owners' equity at December 31, 2015	—	—	(25,876)	253	59,143	(2,791)	9,973	40,702
Net income (loss)	—	—	(6,298)	819	816	—	(4,499)	(9,162
Foreign currency translation adjustment	—	—	—	—	—	253	—	253
Contributions attributable to General Partner	—	—	6,298	—	—	—	—	6,298
Distributions to limited partners	—	—	—	(9,646)	(9,612)	—	—	(19,25
Distributions to non-controlling interests	—	—	—	—	—	—	(424)	(424
Equity-based compensation	—	—	—	959	127	—	—	1,086
Taxes paid related to net share settlement of equity-based compensation	—	—	—	(107)	—	—	—	(107
Owners' equity at December 31, 2016	$ —	$ —	$ (25,876)	$ (7,722)	$ 50,474	$ (2,538)	$ 5,050	$ 19,388

See accompanying notes.

78

CYPRESS ENERGY PARTNERS, L.P.
Consolidated Statements of Cash Flows
For the Years Ended December 31, 2016, 2015 and 2014
(in thousands)

	2016	2015	2014
Operating activities:			
Net income (loss)	$(9,162)	$4,091	$(15,179)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, amortization and accretion	5,788	6,004	6,513
Impairments	10,530	6,645	32,546
(Gain) loss on asset disposals	(19)	(1)	3
Interest expense from debt issuance cost amortization	570	547	714
Equity-based compensation expense	1,086	1,167	785
Equity in earnings of investee	(309)	(102)	(46)
Distributions from investee	200	100	55
Deferred tax benefit, net	(24)	(32)	(13)
Non-cash allocated expenses	3,798	648	497
Changes in assets and liabilities:			
Trade accounts receivable	9,871	9,039	6,650
Prepaid expenses and other	1,350	233	(933)
Accounts payable and accrued payroll and other	478	(1,222)	(2,964)
Income taxes payable	662	(196)	(15,612)
Net cash provided by operating activities	24,819	26,921	13,016
Investing activities:			
Proceeds from fixed asset disposals	46	2	—
Acquisition of 49.9% interest in the TIR Entities (Note 3)	—	(52,588)	—
Cash paid for acquisition of 51% interest in Brown Integrity, LLC, net of cash acquired (Note 3)	—	(10,436)	—
Acquisitions of businesses	—	—	(1,769)
Purchases of property and equipment	(1,376)	(1,857)	(517)
Net cash used in investing activities	(1,330)	(64,879)	(2,286)
Financing activities:			
Proceeds form initial public offering	—	—	80,213
Distribution of initial public offering proceeds to Cypress Energy Holdings, LLC	—	—	(80,213)
Payment of offering costs	—	—	(314)
Payment of debt issuance costs	—	—	(883)
Advances on long-term debt	—	68,800	7,600
Repayments of long-term debt	(4,000)	(5,500)	(5,000)
Taxes paid related to net share settlement of equity-based compensation	(107)	—	—
Contributions from general partner	2,500	—	482
Distributions to members prior to IPO	—	—	(168)
Distributions to limited partners	(19,258)	(19,232)	(13,064)
Distributions to non-controlling members	(424)	(1,567)	(4,683)
Net cash provided by (used in) financing activities	(21,289)	42,501	(16,030)

Effect of exchange rates on cash	343	(1,150)	(633)
Net increase (decrease) in cash and cash equivalents	2,543	3,393	(5,933)
Cash and cash equivalents, beginning of period	24,150	20,757	26,690
Cash and cash equivalents, end of period	$26,693	$24,150	$20,757
Non-cash items:			
Accrued capital expenditures	$—	$100	$756
Supplemental cash flow disclosures:			
Cash taxes paid	$551	$579	$16,674
Cash interest paid	5,859	5,167	2,415

See accompanying notes.

CYPRESS ENERGY PARTNERS, L.P.

Notes to Consolidated Financial Statements

1. Organization and Operations

Cypress Energy Partners, L.P. (the “Partnership”) is a Delaware limited partnership formed in 2013 to provide independent pipeline inspection and integrity services to producers and pipeline companies and to provide salt water disposal (“SWD”) and other water and environmental services to U.S. onshore oil and natural gas producers and trucking companies. Trading of our common units began January 15, 2014 on the New York Stock Exchange under the symbol “CELP.” At our Initial Public Offering (“IPO”), 4,312,500 of our common units were made available to the general public at $20.00 per common unit ($18.70 per common unit, net of underwriting discounts, commissions and fees). We received net proceeds of $80.2 million from the IPO, after deducting underwriting discounts and structuring fees. The net proceeds from the IPO were distributed to Cypress Energy Holdings II, LLC as reimbursement for certain capital expenditures it incurred with respect to assets contributed to us.

Total deferred offering costs of $2.9 million, including costs incurred during the year ended December 31, 2014 of $0.3 million, were charged against the proceeds of the IPO. In addition, the Partnership incurred $0.4 million of offering costs during the year ended December 31, 2014 that were expensed as incurred. These non-recurring costs are reflected as *offering costs* in the Partnership’s Consolidated Statement of Operations.

Our business is organized into the Pipeline Inspection Services (“PIS”), Integrity Services (“IS”) and Water and Environmental Services (“W&ES”) reportable segments. PIS provides pipeline inspection and other services to energy exploration and production (“E&P”), public utility companies (“PUC’s”), and midstream companies and their vendors throughout the United States and Canada. The inspectors of PIS perform a variety of inspection services on midstream pipelines, gathering systems, and distribution systems, including data gathering and supervision of third-party construction, inspection, and maintenance and repair projects.

IS provides independent hydrotesting integrity services to pipeline owners, as well as pipeline construction companies located throughout the United States. Field personnel in this segment primarily perform hydrostatic testing on newly-constructed and existing natural gas and petroleum pipelines.

W&ES provides services to oil and natural gas producers and trucking companies through its ownership and operation of eight commercial SWD facilities in the Bakken Shale region of the Williston Basin in North Dakota and two in the Permian Basin in Texas. All of the facilities utilize specialized equipment and remote monitoring to minimize downtime and increase efficiency for peak utilization. These facilities also contain oil skimming processes that remove oil from water delivered to the sites. In addition to these SWD facilities, we provide management and staffing services for a third-party SWD facility pursuant to a management agreement (see Note 12). We also own a 25% interest in this facility.

2. Basis of Presentation and Significant Accounting Policies

Basis of Presentation

The accompanying Consolidated Financial Statements include our accounts and those of our controlled subsidiaries. All intercompany transactions and account balances have been eliminated. We have made certain reclassifications to the prior period financial statements to conform with classification methods used in the current fiscal year. These reclassifications have had the effect of reducing previously reported total assets and total liabilities, as the adoption of required accounting guidance from the Financial Accounting Standards Board ("FASB") necessitated changes in the presentation of certain assets and liabilities, including the presentation of deferred tax assets and liabilities as noncurrent and the netting of debt issuance costs with its associated debt.

CYPRESS ENERGY PARTNERS, L.P.

Notes to Consolidated Financial Statements - Continued

The accompanying Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States ("GAAP") for consolidated financial information and in accordance with the rules and regulations of the Securities and Exchange Commission. The Consolidated Financial Statements include all adjustments considered necessary for a fair presentation of the financial position and results of operations for the periods presented.

Use of Estimates in the Preparation of Financial Statements

The preparation of the Partnership's Consolidated Financial Statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the Consolidated Financial Statements and accompanying notes. Actual results could differ from those estimates.

Areas requiring the use of assumptions, judgments, and estimates include amounts of expected future cash flows used in determining possible impairments of long-lived assets, the determination of fair values of assets acquired and liabilities assumed in business combinations, and future asset retirement obligations. Certain estimates are inherently imprecise and may change as future information becomes available. The use of alternative judgments and/or assumptions could result in different outcomes.

Fair Value Measurement

The Partnership utilizes fair value measurements to measure assets in a business combination or assess impairment of property and equipment, intangible assets, and goodwill. Fair value is the amount received from the sale of an asset or the amount paid to transfer a liability in an orderly transaction between market participants (an exit price) at the measurement date. Fair value is a market-based measurement considered from the perspective of a market participant. The Partnership uses market data or assumptions that it believes market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation. These inputs can be readily observable, market corroborated, or unobservable. The Partnership applies both market and income approaches for fair value measurements using the best available information while utilizing valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs.

The fair value hierarchy prioritizes the inputs used to measure fair value, giving the highest priority to quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The Partnership classifies fair value balances based on the observability of those inputs. The three levels of the fair value hierarchy are as follows:

Level 1 – Quoted prices for identical assets or liabilities in active markets that management has the ability to access. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Inputs are other than quoted prices in active markets included in Level 1 that are either directly or indirectly observable. These inputs are either directly observable in the marketplace or indirectly observable through corroboration with market data for substantially the full contractual term of the asset or liability being measured.

Level 3 – Inputs that are not observable for which there is little, if any, market activity for the asset or liability being measured. These inputs reflect management's best estimate of the assumptions market participants would use in determining fair value.

Contributions Attributable to General Partner

During the years ended December 31, 2016, 2015, and 2014, Holdings incurred overhead expenses on behalf of the Partnership totaling $3.8 million, $0.6 million and $0.5 million, respectively. These costs represent amounts incurred by Holdings in excess of amounts charged to the Partnership under our omnibus agreement. These expenses are reflected as *general and administrative* in the Consolidated Statements of Operations for the years ended December 31, 2016, 2015, and 2014 and as *contributions attributable to General Partner* in the Consolidated Statement of Owners' Equity.

In addition to incurring the expenses described above, Holdings provided the Partnership with additional temporary financial support by making cash contributions of $2.5 million in 2016 as a reimbursement for certain expenditures incurred by the Partnership. These payments are reflected as a *contribution attributable to general partner* in the Consolidated Statement of Owners' Equity and as a component of the *net loss attributable to the general partner* in the Consolidated Statements of Operations for the year ended December 31, 2016.

Cash and Cash Equivalents

The Partnership considers all investments purchased with initial maturities of three months or less to be cash equivalents. Cash equivalents consist primarily of investments in highly-liquid securities. The carrying amounts of cash and cash equivalents reported in the balance sheet approximate fair value.

As of December 31, 2016, U.S. cash balances are insured by the Federal Deposit Insurance Corporation (FDIC) up to $250,000 per financial institution. Canadian cash balances are insured by the Canada Deposit Insurance Corporation (CDIC) up to $100,000 (Canadian Dollars) per financial institution. At times, cash balances may be in excess of the FDIC or CDIC insurance limits. We periodically assess the financial condition of the institutions where we deposit funds, and, we believe our credit risk related to these funds was minimal at December 31, 2016.

CYPRESS ENERGY PARTNERS, L.P.

Notes to Consolidated Financial Statements - Continued

Property and Equipment

Property and equipment consists of land, land and leasehold improvements, buildings, facilities, wells and equipment, computer and office equipment, and vehicles. The Partnership records property and equipment at cost. Costs of renewals and improvements that substantially extend the useful lives of the assets are capitalized. Maintenance and repairs are expensed as incurred. Depreciation for these assets is computed using the straight-line method over the estimated useful lives of the assets. Upon retirement, impairment, or disposition of an asset, the cost and related accumulated depreciation are removed from the balance sheet and the resultant gain or loss, if any, is reflected in the Consolidated Statement of Operations.

CYPRESS ENERGY PARTNERS, L.P.

Notes to Consolidated Financial Statements - Continued

Debt Issuance Costs

Debt issuance costs represent fees and expenses associated with securing the Partnership's Credit Agreement (see Note 7). Amortization of the capitalized debt issuance costs is computed using the effective interest method over the term of the Credit Agreement.

Income Taxes

As a limited partnership, we generally are not subject to federal, state or local income taxes. The tax on the net income of the Partnership is generally borne by the individual partners. Net income for financial statement purposes may differ significantly from taxable income of the partners as a result of differences between the tax basis and financial reporting basis of assets and liabilities and the taxable income allocation requirements under our partnership agreement. The aggregated difference in the basis of our net assets for financial and tax reporting purposes cannot be readily determined because information regarding each partner's tax attributes is not available to us.

The TIR Entities that have Canadian activity are taxable in Canada. In addition, the Partnership owns three subsidiaries, Tulsa Inspection Resources – PUC, LLC ("TIR-PUC"), Brown Integrity - PUC, LLC, and Cypress Energy Finance Corporation, that have elected to be taxed as corporations for U.S. federal income tax purposes. The amounts recognized as income tax expense, income taxes payable, and deferred tax liabilities in the Consolidated Financial Statements represent the Canadian and U.S. taxes referred to above, as well as partnership-level taxes levied by various states, most notably franchise taxes assessed by the state of Texas.

As a publicly-traded partnership, we are subject to a statutory requirement that our "qualifying income" (as defined by the Internal Revenue Code, related Treasury Regulations, and Internal Revenue Service pronouncements) exceed 90% of our total gross income, determined on a calendar year basis. If our qualifying income does not meet this statutory requirement, we could be taxed as a corporation for federal and state income tax purposes. Our income has met the statutory qualifying income requirement for each year since our IPO.

The Partnership evaluates uncertain tax positions for recognition and measurement in the Consolidated Financial Statements. To recognize a tax position, the Partnership determines whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation, based on the technical merits of the position. A tax position that meets the more likely than not threshold is measured to determine the amount of benefit to be recognized in the Consolidated Financial Statements. The amount of tax benefit recognized with respect to any tax position is measured as the largest amount of benefit that is greater than 50% likely of being realized upon settlement. The Partnership had no uncertain tax positions that required recognition in the financial statements at December 31, 2016 or 2015. Any interest or penalties would be recognized as a component of income tax expense.

CYPRESS ENERGY PARTNERS, L.P.

Notes to Consolidated Financial Statements - Continued

Revenue Recognition

Revenues are recognized when there is persuasive evidence that an arrangement exists, delivery has occurred or services have been rendered, the price is fixed or determinable, and collectability is reasonably assured. Revenues related to pipeline inspection and integrity services are recognized when the services are performed. Water disposal revenues are recognized upon receipt of the wastewater at our disposal facilities. Revenues from sales of oil that is recovered in the process of treasing wastewater are recognized when the oil is delivered to the customer.

Unit-Based Compensation

Our General Partner adopted a long-term incentive plan ("LTIP") under which the Partnership grants equity-based compensation to employees and directors. The cost of such equity-based compensation is measured based on the grant-date fair value of those instruments. That cost is recognized on a straight-line basis over the requisite service period, as described in Note 11.

Net Income (Loss) Per Unit

We utilize the two-class method in calculating basic and diluted income (loss) per common and subordinated unit. *Net income (loss) attributable to partners / controlling interests* is allocated to the general partner and limited partners in accordance with their respective partnership ownership percentages, after giving effect to any specifically allocated items.

For the year ended December 31, 2016, there were 155,877 dilutive phantom restricted units. For the year ended December 31, 2015, there were no dilutive phantom restricted units. For the year ended December 31, 2014, there were 14,520 phantom restricted units; however, as we were in a net loss position, they were excluded from the net income per unit calculation.

Accounts Receivable and Concentration of Credit Risk

We operate in the United States and Canada. We grant unsecured credit to customers under normal industry standards and terms, and have established policies and procedures that allow for an evaluation of each customer's creditworthiness. The Partnership determines accounts receivable allowances based on management's assessment of the creditworthiness of the customers. Trade receivables are written off against the allowance when deemed uncollectible. Recoveries of trade receivables previously written off are recorded when received. The Partnership does not typically charge interest on past due trade receivables and does not require collateral for its trade receivables. The Partnership had an allowance for doubtful accounts of $0.6 million and $0.7 million at December 31, 2016 and 2015, respectively, and recorded bad debt expense of approximately $0.0 million, $0.1 million and $0.1 million in the years ended December 31, 2016, 2015 and 2014, respectively.

We had three customers that each represented more than 10% of total accounts receivable as of December 31, 2016 and 2015. If one or more of these customers were to default on their payment obligations, we may not be able to replace any of these customers in a timely fashion, on favorable terms, or at all. In addition, any downgrade of our customers' receivables from investment grade (defined as BBB- or higher by S&P or Baa3 or higher by Moody's) could reduce our borrowing capacity or potentially place the Partnership at risk of default on the working capital revolving credit facility of our Credit Agreement. The result of downgrades of our customers' receivables could have a material adverse effect on our business, financial condition, results of operations, or cash flows.

The majority of our revenues are generated in the United States. Total revenues generated in Canada were $31.2 million, $27.5 million, and $32.4 million for the years ended December 31, 2016, 2015, and 2014, respectively.

Accrued Payroll and Other

Included in *accrued payroll and other* is $5.6 million and $5.8 million of payroll costs as of December 31, 2016 and 2015, respectively. The remaining amounts relate to various other accrued liabilities.

CYPRESS ENERGY PARTNERS, L.P.

Notes to Consolidated Financial Statements - Continued

Fair Value of Financial Instruments

The carrying amounts reported in the Consolidated Balance Sheets for cash and cash equivalents; trade accounts receivable, net; prepaid expenses and other; accounts payable; accounts payable – affiliates; accrued payroll and other; and income taxes payable approximate their fair values.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are reported at fair value on a nonrecurring basis in the Partnership's Consolidated Balance Sheets. The following methods and assumptions were used to estimate the fair values:

Impairments of Property and Equipment

The Partnership reviews its property and equipment for impairment whenever events or changes in circumstances indicate, in the judgment of management, that a decline in the recoverability of their carrying value may have occurred. When an indicator of impairment exists, the Partnership compares its estimate of undiscounted cash flows attributable to the assets to the carrying value of the assets to determine whether an impairment has occurred. If the estimate of undiscounted cash flows is less than the carrying value of the asset group, the Partnership determines the amount of the impairment recognized in the financial statements by estimating the fair value of the assets and records a loss for the amount by which the carrying value exceeds the estimated fair value. Assets are grouped for impairment purposes at each SWD facility in the W&ES segment, as these asset groups represent the lowest level as which cash flows are separately identifiable. The Partnership recorded impairment losses to property, plant, and equipment of $2.1 million, $6.6 million, and $12.8 million for the years ended December 31, 2016, 2015 and 2014, respectively (see Note 4). Unfavorable changes in the future are reasonably possible, and therefore it is possible that we may incur additional impairment charges in the future.

Goodwill

At December 31, 2016 and 2015, the Partnership had $56.9 million and $65.3 million of goodwill, respectively. Goodwill is not amortized, but is subject to annual reviews on November 1 for impairment at a reporting unit level. The reporting units used to evaluate and measure goodwill for impairment are determined primarily from the manner in which the business is managed or operated. We have determined that our PIS, IS, and W&ES operating segments are the appropriate reporting units for testing goodwill impairment. The accounting estimate relative to assessing the impairment of goodwill is a critical accounting estimate for each of our operating segments.

For our PIS reporting unit, we performed qualitative assessments to determine whether the fair value of the reporting unit was less than its carrying value. Our evaluations consisted of assessing various qualitative factors including current and projected future earnings, capitalization, current customer relationships and projects, and the impact of lower crude oil prices on our earnings. The qualitative assessment on this reporting unit indicated that there was no need to conduct further quantitative testing for goodwill impairment. Different judgments from those we used in our qualitative analysis could have resulted in the requirement to perform a quantitative goodwill impairment analysis.

During 2016, for our IS and W&ES segments, after giving consideration to certain qualitative factors, including trends in the energy industry and recorded impairments of property and equipment, we elected to perform quantitative goodwill impairment analyses. We computed the fair values of the reporting units using multiple valuation methodologies, including market approaches (market price multiples of comparable companies) and income approaches (discounted cash flow analyses). These approaches are consistent with the requirement to utilize all appropriate valuation techniques as described in ASC 820-10-35-24 "*Fair Value Measurements and Disclosures.*" Given recent declines in the price of crude oil and the related impact on the valuations of energy related companies, relevant market data was difficult to obtain and was of limited usefulness. Accordingly, we relied heavily on the use of the income approach for the valuations of the reporting units.

Based on our valuation, we determined that the goodwill in our IS segment was impaired as of June 30, 2016 by $8.4 million (see Note 5). During 2014, we determined that the carrying value of the W&ES reporting unit exceeded the fair value of the reporting unit, resulting in a goodwill impairment charge of $19.8 million. Further unfavorable changes in the future are reasonably possible, and therefore it is possible that we may incur additional impairment charges in the future.

CYPRESS ENERGY PARTNERS, L.P.

Notes to Consolidated Financial Statements - Continued

Intangible Assets

Intangible assets include acquired customer relationships, trade names, and certain other intangibles acquired via various acquisitions and have been recorded utilizing various assumptions to determine fair market value including, but not limited to, replacement costs, liquidation values, future cash flows on a discounted basis of the net assets acquired, pay-off values, and average royalty rates. Due to the unobservable nature of these assumptions, these fair value measurements are considered to be Level 3 fair value estimates. Amortization of intangible assets is computed utilizing the straight-line method over their estimated useful lives, typically 5 – 20 years (see Note 6).

We review our intangible assets for impairment whenever events or changes in circumstances indicate we should assess the recoverability of the carrying amount of the intangible asset. We recognized no impairments for other intangible assets in 2016 or 2015.

Should we continue to experience a continued, prolonged energy market down turn resulting in further declines in revenues and cash flows, we could incur additional impairment charges associated with our property and equipment, goodwill, or intangible assets.

Non-controlling Interest

The non-controlling interests shown in our Consolidated Financial Statements reflect interests in consolidated subsidiaries that we own less than 100% of, but over which we exercise control.

Business Combinations

The Partnership evaluates all potential acquisitions and changes in control to determine whether it has purchased or acquired control of a business. If the acquired or newly-controlled assets meet the definition of a business, the transaction is accounted for as a business combination; otherwise it is accounted for as an asset acquisition. Transactions discussed in Note 3 were accounted for as business combinations for the periods described.

Foreign Currency Translation

The reporting currency is the U.S. dollar. Non-U.S. dollar denominated monetary items are translated into U.S. dollars at the rate of exchange in effect at the balance sheet date. Non-U.S. dollar denominated non-monetary items are translated to U.S. dollars at the exchange rate in effect when the transactions occur. Revenues and expenses denominated in foreign currencies are translated at the exchange rate in effect during the period. Foreign exchange gains or losses on translation are included in other comprehensive income.

New Accounting Standards

In 2016 the Partnership has adopted the following new accounting standards issued by the Financial Accounting Standards Board ("FASB");

The FASB issued Accounting Standards Update ("ASU") 2015-17 – *Income Taxes* in November 2015. ASU 2015-17 was issued as a part of the FASB's initiative to reduce complexity in accounting standards. The Partnership adopted this guidance beginning January 1, 2016. The guidance simplifies the presentation of deferred income taxes by requiring deferred tax assets and liabilities to be classified as noncurrent in a classified consolidated balance sheet. Therefore, the Partnership's deferred tax assets and liabilities have been classified as noncurrent in the Consolidated Balance Sheets for the periods presented.

The FASB issued ASU 2015-03 – *Interest – Imputation of Interest* in April 2015. This guidance requires certain debt issuance costs to be presented on the balance sheet as a reduction of the carrying amount of the long-term debt. The Partnership has adopted this guidance beginning January 1, 2016. As a result of the adoption of this ASU, netted debt issuance costs against *long-term debt* for all periods presented, moving the debt issuance costs from noncurrent assets to noncurrent liabilities on the Partnership's Consolidated Balance Sheets.

The FASB issued ASU 2014-15 – *Presentation of Financial Statements – Going Concern* in August 2014. ASU 2014-15 applies to all entities and is effective for the annual period ending after December 15, 2016 and for annual and interim periods thereafter and will be applied prospectively. Early application is permitted. This standard requires the Partnership's management to assess our ability to continue as a going concern. The amendments (1) require an evaluation every reporting period (including interim periods), (2) provide principles for considering the mitigating effect of management's plans, (3) require certain disclosures when substantial doubt is alleviated as a result of consideration of management's plans, (4) require an express statement and other disclosures when substantial doubt is not alleviated, and (5) require an assessment for a period of one year after the date that the financial statements are issued (or available to be issued). This guidance is intended to reduce diversity in the timing and content of footnote disclosures related to an entity's going concern. The adoption of this guidance did not affect our financial position, results of operations or cash flows.

Other accounting guidance proposed by the FASB that may have some impact on the Consolidated Financial Statements of the Partnership, but have not yet been adopted by the Partnership include:

The FASB issued ASU 2017-04 – *Intangibles – Goodwill and Other* in January 2017. The objective of this guidance is to simplify how an entity is required to test goodwill for impairment by eliminating Step 2 from the goodwill impairment test. Step 2 measures a goodwill impairment loss by comparing the implied fair value of a reporting unit's goodwill with the carrying amount of that goodwill. Instead, the Partnership will be required to perform its annual goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount. In the event the carrying amount exceeds the reporting unit's fair value, a goodwill impairment charge for the excess will be recorded (not exceeding the recorded amount of the reporting unit's goodwill). The Partnership will be required to adopt the amendments in this ASU for its annual goodwill impairment tests in fiscal years beginning after December 15, 2019. Early adoption is permitted for annual goodwill impairment tests performed on testing dates after January 1, 2017. The Partnership is currently evaluating whether to early adopt this guidance and the potential effects adoption may have on our financial position, results of operations and cash flows.

Also in January 2017, the FASB issued ASU 2017-01 – *Business Combinations*. The intent of this ASU is to clarify the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. The Partnership will be required to apply the provisions in the ASU to acquisitions occurring in annual periods beginning after December 15, 2017 and should be applied prospectively. Early application is allowed. The Partnership anticipates that the adoption of this guidance will not materially affect our financial position, results of operations or cash flows.

The FASB issued ASU 2016-15 – *Statement of Cash Flows* in August 2016. This guidance was issued to address diversity in practice of how cash receipts and cash payments are presented and classified in the statement of cash flows. It specifically addresses eight cash flow issues with the objective of reducing the current existing diversity in practice. Specific portions of the guidance that may apply directly to the Partnership include (1) the classification of debt prepayment or debt extinguishment costs, (2) classification of contingent consideration payments made after a business combination, (3) classification of distributions received from equity method investees, and potentially (4) the classification of separately identifiable cash flows and application of the predominance principle. Current GAAP is either unclear or does not include specific guidance on the classification issues addressed in this ASU. These amendments are effective for fiscal years beginning after December 15, 2017 and interim periods with those fiscal years and will be retrospectively applied to each period presented. The Partnership has not yet determined the impact this guidance may have on the Consolidated Financial Statements, but since the ASU addresses classification issues, the Partnership does not expect the adoption of this guidance to materially affect our financial position, results of operations or cash flows.

The FASB issued ASU 2016-09 – *Compensation – Stock Compensation* in March 2016. The purpose of the guidance is to simplify several aspects of the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The amendments in this ASU are effective for fiscal years beginning after December 15, 2016, and all interim periods within that year. Amendments are to be applied retrospectively or prospectively, depending on the specific provision included in the ASU. We will adopt this guidance in the first quarter of 2017 and are still assessing whether to account for forfeitures when they occur or continue to record expense based on estimates of future forfeitures. Should we make the policy election to account for forfeitures as they occur, we would be required to record a cumulative-effect adjustment to owners' equity as of the beginning of 2017, which would reduce partners' capital by approximately $0.3 million.

The FASB issued ASU 2016-02 – *Leases* in February 2016. This guidance was proposed in an attempt to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. The main difference between previous GAAP and this new guidance is the recognition on the balance sheet of lease assets and lease liabilities by lessees for leases that have been classified as operating leases under previous GAAP. The amendments in this ASU are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years and will be retrospectively applied to each period presented. Early application is permitted. We are currently assessing the impact this guidance will have on our Consolidated Financial Statements.

The FASB issued ASU 2014-09 – *Revenue from Contracts with Customers* in May 2014. ASU 2014-09 is intended to clarify the principles for recognizing revenue and to develop a common standard for recognizing revenue for GAAP and International Financial Reporting Standards that is applicable to all organizations. The Partnership will be required to adopt this standard in 2018 and to apply its provisions retrospectively to each prior reporting period presented or retrospectively with the cumulative effect of initially applying the ASU recognized at the date of initial application (modified retrospective method). Although we continue to evaluate the financial impact of this ASU on the Partnership, we currently plan to adopt this standard utilizing the modified retrospective method and do not anticipate that the adoption of this ASU will materially impact our financial position, results of operations or cash flows.

CYPRESS ENERGY PARTNERS, L.P.

Notes to Consolidated Financial Statements - Continued

3. Business Combinations

2015 Business Combinations

Brown Integrity, LLC

On May 6, 2015, the Partnership acquired a 51% interest in Brown, a pipeline integrity services business focused on hydrostatic testing. The purchase price was $10.4 million (net of cash acquired) and was financed through the Partnership's credit facilities. The Partnership also has the right, but not the obligation, to acquire the remaining 49% of Brown commencing May 1, 2017 pursuant to a formula that would yield a maximum additional purchase price of $28.0 million in any combination of cash and Partnership units. The effective date of the transaction was May 1, 2015.

The acquisition of Brown was accounted for under the acquisition method of accounting. We recognized amounts for assets acquired and liabilities assumed at their estimated acquisition date fair values based on discounted cash flow projections, estimated replacement cost and other valuation techniques. The Partnership used an estimate of replacement cost, based on comparable market prices, to value the acquired property and equipment and utilized discounted cash flows to value the intangible assets. Key assumptions used in the valuations included projections of future operating results and the Partnership's estimated weighted-average cost of capital. Due to the unobservable nature of these inputs, these estimates are considered Level 3 fair value estimates.

The estimated fair values of the assets acquired and liabilities assumed as of the purchase date were as follows:

	(in thousands)
Cash	$ 175
Accounts receivable	3,229
Other current assets	108
Property and equipment	2,578
Intangible assets:	
Customer relationships	3,128
Trade names and trademarks	2,049

Non-compete agreements	143
Goodwill	9,992
	21,402
Current liabilities	1,294
Non-controlling interests	9,497
Net assets acquired	$10,611

CYPRESS ENERGY PARTNERS, L.P.

Notes to Consolidated Financial Statements - Continued

Intangible assets are amortized on a straight-line basis over periods ranging from 5 – 10 years. Goodwill represented the excess of the purchase price and the fair value of non-controlling interests over the fair value of identified tangible and intangible assets less the fair value of liabilities assumed. The Partnership believed that the locations, synergies created, and the projected future cash flows of Brown merited the recognition of this asset. The goodwill is fully deductible for income tax purposes by our partners.

The operating results of Brown are included in our Integrity Services segment which was created during the second quarter of 2015 in conjunction with the Brown acquisition (see Note 14).

TIR Entities

Effective February 1, 2015, the Partnership acquired the remaining 49.9% interest in the TIR Entities previously held by affiliates of Holdings for $52.6 million. We financed this acquisition with borrowings under our acquisition revolving credit facility (see Note 7). The amount paid in excess of the previously recorded non-controlling interest in the TIR Entities has been reflected in the Consolidated Statement of Owners' Equity as a reduction to the General Partner's capital.

2014 Business Combination

SWD Acquisition

Effective December 1, 2014, we acquired a recently-constructed commercial SWD facility from SBG Energy (a related party at the time) for a total purchase price of approximately $1.7 million. The facility had minimal operating activity prior to the acquisition. The acquisition was accounted for under the acquisition method of accounting. Accordingly, we recognized amounts for assets acquired and liabilities assumed at their estimated acquisition date fair values. The Partnership used various assumptions to determine fair value including, but not limited to, replacement costs, liquidation values, and future cash flows on a discounted basis.

The estimated fair values of the assets acquired and liabilities assumed as of the purchase date were as follows:

	(in thousands)
Current assets	$ 50
Property and equipment	1,837
Intangible assets:	
Contracts	241
	2,128
Current liabilities	386
Asset retirement obligation	1
Net assets acquired	$ 1,741

In addition to the amounts reflected above, the Partnership incurred additional capital costs of approximately $0.4 million to complete the SWD facility.

CYPRESS ENERGY PARTNERS, L.P.

Notes to Consolidated Financial Statements - Continued

4. Property and Equipment

Property and equipment consist of the following, recorded at cost, as of December 31, 2016 and 2015:

Asset Category	Useful Lives (years)	December 31, 2016	2015
		(in thousands)	
Land		$1,278	$2,114
Land improvements	15	698	848
Buildings and leasehold improvements	30 - 39	1,242	1,396
Facilities, wells, and equipment	5 - 15	17,563	17,711
Computer and office equipment	3 - 9	1,268	1,213
Vehicles and other	3 - 5	410	424
		22,459	23,706
Less accumulated depreciation		(7,840)	(5,369)
Net property and equipment		$14,619	$18,337

Depreciation expense is computed using the straight-line method over the estimated useful lives of the assets. Depreciation expense was $2.9 million, $3.1 million and $4.1 million for the Partnership for the years ended December 31, 2016, 2015 and 2014, respectively, of which $0.9 million, $0.6 million and $0.2 million was included as a component of costs of services for the years ended December 31, 2016, 2015 and 2014, respectively. As a result of our impairment analyses, we wrote down the value of certain property and equipment which resulted in a decreases in accumulated depreciation of $0.3 million, $1.3 million $4.3 million in 2016, 2015 and 2014, respectively.

During 2016, 2015 and 2014, the Partnership recognized impairments of property and equipment at a number of its SWD facilities. At each of these facilities, the Partnership has experienced revenue and volume decreases due to lower commodity pricing and increasing competition and has forecasted decreases in drilling activity affecting volumes and revenues over the remaining life of the underlying assets. Given these indicators of impairment, the Partnership compared its estimates of undiscounted future cash flows from the facilities to the carrying amounts of the long-lived assets of the facilities, and determined they were no longer recoverable and were impaired. The Partnership recognized impairments on the facilities totaling $2.1 million, $6.6 million and $12.8 million, included in the *impairments* caption on the Consolidated Statement of Operations for the years ended December 31, 2016, 2015 and 2014, respectfully.

The following table summarizes the impaired property and equipment in our W&ES segment for the years ended December 31, 2016, 2015 and 2014:

Asset Category	2016	2015	2014
	(in thousands)		
Land	$1,000	$587	$1,527
Land improvements	157	385	2,034
Buildings and leasehold improvements	136	568	1,054
Facilities, wells and equipment	1,726	6,951	19,679
Computer and office equipment	—	4	5
Vehicles and other	5	5	10
	3,024	8,500	24,309
Less accumulated depreciation	(289)	(1,268)	(4,296)
Net book value of impaired properties prior to impairment	2,735	7,232	20,013
Estimated fair market value of impaired properties as of date of impairment	616	587	7,241
Impairments	$2,119	$6,645	$12,772

Fair value was determined using expected future cash flows, which is a Level 3 input as defined in ASC 820, *Fair Value Measurement*. The cash flows are those expected to be generated by the market participants, discounted at the Partnership's estimated cost of capital. Because of the uncertainties surrounding the SWD facilities and the market conditions, including the Partnership's ability to generate and maintain sufficient revenues to operate the facilities profitably, our estimate of expected future cash flows may change in the future resulting in the need to further adjust our determinations of fair value.

CYPRESS ENERGY PARTNERS, L.P.

Notes to Consolidated Financial Statements - Continued

5. Goodwill

Goodwill represents the excess of cost over fair value of the assets and liabilities of businesses acquired. Changes in goodwill are as follows:

	PIS	IS	W&ES	Total
		(in thousands)		
Balance - December 31, 2014	$40,470	$—	$15,075	$55,545
Goodwill from business combination	—	9,992	—	$9,992
Foreign currency translation	(264)	—	—	$(264)
Balance - December 31, 2015	40,206	9,992	15,075	65,273
Impairments	—	(8,411)	—	(8,411)
Foreign currency translation	41	—	—	41
Balance - December 31, 2016	$40,247	$1,581	$15,075	$56,903

Goodwill is not amortized, but is subject to annual reviews on November 1 for impairment at a reporting unit level. In accordance with ASC 350 "*Intangibles — Goodwill and Other*", we have assessed the reporting unit definitions and determined that the PIS, IS and W&ES operating segments are the appropriate reporting units for testing goodwill for impairment. The accounting estimate relative to assessing the impairment of goodwill is a critical accounting estimate for each of our reporting segments.

For our PIS reporting unit, we performed qualitative assessments to determine whether the fair value of the reporting unit was more likely than not less than its carrying value. Our evaluations consisted of assessing various qualitative factors including current and projected future earnings, capitalization, current customer relationships and projects, and the impact of lower crude oil prices on our earnings. The qualitative assessments on this reporting unit indicated that there was no need to conduct further quantitative testing for goodwill impairment. Different judgments from those we used in our qualitative analyses could result in the requirement to perform quantitative goodwill impairment analyses.

For our IS and W&ES segments, after giving consideration to certain qualitative factors including trends in the energy industry, we elected to perform quantitative goodwill impairment analyses. We computed the fair value of the reporting units employing multiple valuation methodologies, including a market approaches (market price multiples of comparable companies) and a income approaches (discounted cash flow analysis). These approaches are consistent with the requirement to utilize all appropriate valuation techniques as described in ASC 820-10-35-24 "*Fair Value*

Measurements and Disclosures." Given recent declines in the price of crude oil and the related impact on the valuations of energy related companies, relevant market data was difficult to obtain and was of limited usefulness. Accordingly, we relied heavily on the use of the income approaches for the valuations of the reporting units.

In the IS segment, we experienced declining revenues in 2016 due to the overall depressed energy economy, including decreased new infrastructure construction, postponement of inspection and integrity activity by our E&P customers and reduced revenues and margins on completed contracts due to increased competition, among other things. Given these indicators of impairment, we determined a triggering event occurred in the second quarter of 2016 and thus, performed an interim impairment assessment of the approximately $10.0 million of goodwill related to our IS segment. We estimated the fair value of the reporting unit utilizing the income approach (discounted cash flows) valuation method, which is a Level 3 input as defined in ASC 820, *Fair Value Measurement*. Significant inputs in the valuation included projections of future revenues, anticipated operating costs and appropriate discount rates. To estimate the fair value of the reporting unit and the implied fair value of goodwill under a hypothetical acquisition of the reporting unit, we assumed a tax structure where a buyer would obtain a step-up in the tax basis of the net assets acquired. Significant assumptions used in valuing the reporting unit included revenue growth rates ranging from 2% to 5% annually and a discount rate of 17.5%. In our assessment, the carrying value of the reporting unit, including goodwill, exceeded its estimated fair value. We then determined through our hypothetical acquisition analysis that the fair value of goodwill was impaired. As a result, we recorded an impairment loss of $8.4 million in our IS segment and reduced the value of recorded goodwill to $1.6 million in the second quarter of 2016. This impairment is included in *impairments* on the Consolidated Statement of operations for the year ended December 31, 2016.

The W&ES segment has experienced increased competition in the regions in which we operate which has resulted in declining volumes and increased pricing pressure. Steady and continued declines in oil prices have intensified competitive pressures and had a direct impact on our revenues. Many of our customers have announced significantly reduced drilling programs in the Bakken. The decline in drilling will directly impact the amount of flowback and produced water that we process and dispose. The energy downturn is also expected to continue to negatively impact our pricing as our customers look for ways to reduce costs. In addition, as we process lower water volumes, in particular flowback water volumes directly attributable to drilling, we will recover less skim oil. SWD property and equipment were impaired in the second quarter of 2016 and in the fourth quarter of 2015 due to continued declines in disposed volumes and depressed prices. Based on our analyses, we determined that the carrying value of the W&ES reporting unit was less than the estimated fair market value and therefore, there was no goodwill impairment adjustment for 2016 or 2015. However, in 2014, we determined that the carrying value of the W&ES reporting unit exceeded the fair value of the reporting unit resulting in a goodwill impairment charge of $19.8 million. Additionally, further unfavorable changes in the future are reasonably possible, and therefore, it is possible that we may incur additional impairment charges in the future.

During the fourth quarter 2016, we performed qualitative assessments on each of our reporting units to determine whether the fair values of the reporting units were more likely than not to be lower than their respective carrying values. Our evaluation consisted of assessing various qualitative factors, including projected future earnings, recent trends in earnings, market capitalization, current customer relationships and projects, and current economic conditions. In addition, as we continued to monitor the value of our IS segment (Brown) through the end of 2016, we performed additional quantitative calculations to determine if the IS goodwill may be impaired beyond that which was recorded in the second quarter of 2016. The qualitative and quantitative assessments in these reporting units indicated the fair values of the reporting units exceeded their carrying values and the goodwill of the reporting units was not impaired as of November 1 or December 31, 2016. Our IS reporting unit experienced a downward trend in revenues during 2016. Our estimate of the fair value of the IS segment assumes that our revenues in future years will be higher than in 2016, which we believe to be a reasonable estimate based on historical results, management's plans for growing revenues of the segment, and management's economic outlook for the industry. While we believe we have made reasonable estimates and assumptions to estimate the fair values of our reporting units, it is reasonably possible that changes could occur that would require a goodwill impairment charge in the near future.

CYPRESS ENERGY PARTNERS, L.P.

Notes to Consolidated Financial Statements - Continued

6. Intangible Assets

Intangible assets consist of the following at December 31, 2016 and 2015:

Asset Category	Useful Lives (years)	December 31, 2016	December 31, 2015
		(in thousands)	
Customer relationships	5 - 20	$24,261	$24,257
Contracts	3	241	241
Non-compete agreements	3	143	143
Trademarks and trade names	10	12,079	12,067
Inspector database	10	2,080	2,080
		38,804	38,788
Less accumulated amortization		(9,180)	(6,302)
Net intangibles		$29,624	$32,486

Amortization expense for the years ended December 31, 2016, 2015 and 2014 was $2.9 million, $2.8 million and $2.4 million respectively.

Future amortization expense of our intangible assets is estimated to be as follows:

Year ending December 31,	(in thousands)
2017	$ 2,917
2018	2,829
2019	2,807
2020	2,786
2021	2,778
Thereafter	15,507
	$ 29,624

CYPRESS ENERGY PARTNERS, L.P.

Notes to Consolidated Financial Statements - Continued

7. Credit Agreement

The Partnership is party to a credit agreement (as amended, the "Credit Agreement") that provides up to $200.0 million in borrowing capacity, subject to certain limitations. The Credit Agreement includes a working capital revolving credit facility ("Working Capital Facility") which provides up to $75.0 million in borrowing capacity to fund working capital needs and an acquisition revolving credit facility ("Acquisition Facility") which provides up to $125.0 million in borrowing capacity to fund acquisitions and expansion projects. In addition, the Credit Agreement contains an accordion feature that allows us to increase the availability under the facilities by an additional $125.0 million if lenders agree to increase their c ommitments. The Credit Agreement matures on December 24, 2018.

Outstanding borrowings at December 31, 2016 and 2015 under the Credit Agreement were as follows:

	December 31,	
	2016	2015
	(in thousands)	
Working capital facility	$48,000	$52,000
Acquisition facility	88,900	88,900
Total borrowings	136,900	140,900
Debt issuance costs	1,201	1,771
Long-term debt	$135,699	$139,129

The carrying value of the partnership's long-term debt approximates fair value, as the borrowings under the Credit Agreement are considered to be priced at market for debt instruments having similar terms and conditions (Level 2 of the fair value hierarchy).

Borrowings under the Working Capital Facility are limited by a monthly borrowing base calculation as defined in the Credit Agreement. If, at any time, outstanding borrowings under the Working Capital Facility exceed the Partnership's calculated borrowing base, a principal payment in the amount of the excess is due upon submission of the borrowing base calculation. Available borrowings under the Acquisition Facility may be limited by certain financial covenant ratios as defined in the Credit Agreement. The obligations under our Credit Agreement are secured by a first priority lien on substantially all assets of the Partnership.

All borrowings under the Credit Agreement bear interest, at our option, on a leveraged based grid pricing at (i) a base rate plus a margin of 1.25% to 2.75% per annum ("Base Rate Borrowing") or (ii) an adjusted LIBOR rate plus a margin of 2.25% to 3.75% per annum ("LIBOR Borrowings"). The applicable margin is determined based on the leverage ratio of the Partnership, as defined in the Credit Agreement. Generally, the interest rate on our Credit Agreement borrowings ranged between 3.54% and 4.52% for the year ended December 31, 2016, 2.68% and 4.17% for the year ended December 31, 2015 and 2.65% and 3.50% for the year ended December 31, 2014. Interest on Base Rate Borrowings is payable monthly. Interest on LIBOR Borrowings is paid upon maturity of the underlying LIBOR contract, but no less often than quarterly. Commitment fees are charged at a rate of 0.50% on any unused credit and are payable quarterly.

Our Credit Agreement contains various customary affirmative and negative covenants and restrictive provisions. Our Credit Agreement also requires maintenance of certain financial covenants, including a combined total adjusted leverage ratio (as defined in our Credit Agreement) of not more than 4.0 to 1.0 and an interest coverage ratio (as defined in our Credit Agreement) of not less than 3.0 to 1.0. At December 31, 2016, our combined total adjusted leverage ratio was 3.41 to 1.0 and our interest coverage ratio was 3.78 to 1.0, pursuant to the Credit Agreement. Upon the occurrence and during the continuation of an event of default, subject to the terms and conditions of our Credit Agreement, the lenders may declare any outstanding principal of our Credit Agreement debt, together with accrued and unpaid interest, to be immediately due and payable and may exercise the other remedies set forth or referred to in our Credit Agreement. We were in compliance with all debt covenants as of December 31, 2016 and expect to remain in compliance with all of our financial debt covenants for the next twelve months following the filing of this Form 10-K. Working capital borrowings, which are fully secured by the Partnership's net working capital, are subject to a monthly borrowing base and are excluded from the Partnership's debt compliance ratios.

In addition, our Credit Agreement restricts our ability to make distributions on, or redeem or repurchase, our equity interests. However, we may make distributions of available cash so long as, both at the time of the distribution and after giving effect to the distribution, no default exists under our Credit Agreement, the borrowers and the guarantors are in compliance with the financial covenants, the borrowing base (which includes 100% of cash on hand) exceeds the amount of outstanding credit extensions under the Working Capital Facilities by at least $5.0 million, and at least $5.0 million in lender commitments are available to be drawn under the Working Capital Facility.

CYPRESS ENERGY PARTNERS, L.P.

Notes to Consolidated Financial Statements - Continued

The following table reflects the changes in long-term debt during the year:

Long-term debt	Working Capital Facility	Acquisition Facility	Total
	(in thousands, except %'s)		
Balance - December 31, 2015	$52,000	$ 88,900	$140,900
Payments	4,000	—	4,000
Balance - December 31, 2016	$48,000	$ 88,900	$136,900
Weighted average interest rate at December 31, 2016	3.91 %	4.48 %	

8. Income Taxes

As a limited partnership, we generally are not subject to federal, state or local income taxes. The tax on the net income of the Partnership is generally borne by the individual partners. We have Canadian activity that is taxable in Canada. In addition, we own three entities which have elected to be taxed as corporations for U.S. federal income tax purposes. The amounts recognized as income tax expense, income taxes payable, and deferred tax liabilities in the Consolidated Financial Statements represent the Canadian and U.S. taxes referred to above, as well as partnership-level taxes levied by various states (primarily Texas).

CYPRESS ENERGY PARTNERS, L.P.

Notes to Consolidated Financial Statements - Continued

Significant components of income tax expense (benefit) are as follows for the years ended December 31:

	2016	2015	2014
		(in thousands)	
Current tax expense (benefit)			
U.S. federal	$ 527	$ (123)	$ 38
State	690	501	332
Canadian	3	6	100
Total	1,220	384	470
Deferred tax expense (benefit)			
U.S. federal	(27)	45	(12)
State	(8)	13	(3)
Canadian	10	10	13
Total	(25)	68	(2)
Total income tax expense	$ 1,195	$ 452	$ 468

The increase in total income tax expense from 2015 to 2016 is primarily attributable to improved operating results of Tulsa Inspection Resources – PUC, LLC, an entity that has elected to be taxable as a corporation for federal and state income tax purposes. Revenues and net taxable income of this entity have increased from the year ended December 31, 2015 to the year ended December 31, 2016.

Non-current deferred tax liabilities of $0.4 million are primarily attributable to the recorded unamortized portion of book intangible assets in our Canadian subsidiary.

The following table reconciles the differences between the U.S. federal statutory rate of 35% to the Partnership's income tax expense on the Consolidated Statements of Operations for the years ended December 31:

	2016	2015	2014
		(in thousands)	
Tax (benefit) computed at statutory rate	$ (2,788)	$ 1,590	$ (5,149)

(Income) loss not subject to federal tax	3,336	(1,790)	5,274
State income taxes, net of federal benefit	644	514	326
Other	3	138	17
	$1,195	$452	$468

The Internal Revenue Service began an income tax audit of the 2012 Tulsa Inspection Resources, Inc. (the predecessor of the TIR Entities) federal income tax return beginning in January 2016. The Omnibus Agreement described in Note 12 provides that Holdings will indemnify us for certain liabilities associated with operations prior to the closing of the IPO should they arise in the course of this examination. To date, there have been no audit adjustments made to that corporate income tax return as filed. Tax years that remain subject to examination by various taxing authorities for each of our consolidated entities include the years 2012 through 2016. It is the Partnership's policy to recognize tax-related interest and penalties as a component of income tax expense in the year incurred. Tax-related interest and penalties were insignificant in the years ended December 31, 2016, 2015 and 2014.

As of December 31, 2016, the Partnership had no significant unrecognized tax benefits. During the next twelve months, we do not expect that the ultimate resolution of any uncertain tax positions will result in a significant increase or decrease of an unrecognized tax benefit.

CYPRESS ENERGY PARTNERS, L.P.

Notes to Consolidated Financial Statements - Continued

9. Parent Net Investment and Owners' Equity

Parent Net Investment

For the periods prior to the IPO, the net equity of the contributed entities is included in *parent net investment attributable to controlling interest* in the Consolidated Statement of Owners' Equity as of December 31, 2013. Also, prior to the IPO, CEP LLC provided treasury and accounts payable services for Holdings and other affiliates. Amounts paid on behalf of Holdings and its affiliates, net of cash transfers from Holdings, are included as a component of parent net equity. Cumulative advances for the periods prior to the IPO were $0.2 million.

Common Units and Subordinated Units

As of December 31, 2016, there are 5,945,348 common units and 5,913,000 subordinated units outstanding. Items of income (loss) are allocated to common units and subordinated units equally. The common unitholders had the right to receive the minimum quarterly cash distributions of $0.3875 per common unit, plus any arrearages in the payment of the minimum quarterly distributions on the common units from prior quarters, before any distributions of available cash could be made on the subordinated units. The subordinated units converted to common units on February 14, 2017 upon satisfaction of the requirements as outlined in our partnership agreement. For the years ended December 31, 2016, 2015, and 2014, there were no limitations or arrearages related to the quarterly distributions made by the Partnership.

Incentive Distribution Rights

Our General Partner owns a 0.0% non-economic general partnership interest in the Partnership, which does not entitle it to receive cash distributions. Affiliates of our General Partner hold incentive distribution rights ("IDRs"), which represent the right to receive an increasing percentage (15%, 25%, and 50%) of quarterly distributions of available cash from operating surplus after specified target distribution levels have been achieved. Affiliates of the General Partner would begin receiving incentive distribution payments when the quarterly cash distribution exceeds $0.445625 per unit. There were no incentive distribution payments in 2016, 2015, or 2014.

97

CYPRESS ENERGY PARTNERS, L.P.

Notes to Consolidated Financial Statements - Continued

10. Major Customers

For the year ended December 31, 2016, 2015 and 2014, three customers individually exceeded 10% of our consolidated total revenues: Enbridge Energy Partners, Pacific Gas and Electric Company and Plains All America Pipeline in 2016 and Enbridge Energy Partners, Enterprise Products Partners and Plains All America Pipeline in 2015 and 2014. No other customer accounted for more than 10% of our consolidated revenues during these years. Revenues from these customers resulted from inspection operations, which are activities conducted by our PIS segment.

11. Equity Compensation

Partnership Long-Term Incentive Plan ("LTIP")

Effective at the closing of the IPO, our General Partner adopted an LTIP that authorized up to 1,182,600 units, representing 10% of the initial outstanding units. Certain directors and employees of the Partnership have been awarded Phantom Restricted Units ("Units") under the terms of the LTIP. The fair value of the awards issued is determined based on the quoted market value of the publicly-traded common units at each grant date, adjusted for a forfeiture rate and other discounts attributable to the units awarded. Compensation expense is recognized straight-line over the vesting period of the grant. Prior to 2015, Holdings reimbursed the Partnership for the direct expense of the awards and allocated the expense to us through the annual administrative fee provided for under the terms of our amended and restated omnibus agreement (see Note 12). For the years ended December 31, 2016, 2015 and 2014, compensation expense of $1.1 million, $1.2 million and $0.5 million, respectively was recorded under the LTIP (including expense associated with subordinated unit awards described below). The following table sets forth the units granted and forfeitured under the LTIP for the years ended December 31, 2016, 2015 and 2014:

	Number of Units	Weighted Average Grant Date Fair Value / Unit
Units at January 1, 2014	—	
Units granted	178,264	$ 17.96
Units forfeited	(19,911)	$ 16.78

Units at December 31, 2014	158,353	$ 18.11
Units granted	230,310	$ 12.08
Units vested and issued	(7,467)	$ 19.72
Units forfeited	(19,498)	$ 16.92
Units at December 31, 2015	361,698	$ 14.30
Units granted	346,999	$ 6.32
Units vested and issued	(36,505)	$ 16.17
Units forfeited	(98,290)	$ 11.38
Units at December 31, 2016	573,902	$ 9.86

The majority of the common unit awards vest in three tranches, with one-third of the units vesting three years from the grant date, one-third vesting four years from the grant date, and one-third vesting five years from the grant date. However, certain of the awards have different, and typically shorter, vesting periods. Two grants, totaling 77,495 units, vest three years from the grant dates, contingent upon the recipient meeting certain performance targets. Total unearned compensation associated with the LTIP at December 31, 2016 and 2015 was $3.8 million and $3.8 million, respectively, with an average remaining life of 2.4 years and 3.3 years, respectively.

In conjunction with the IPO, phantom profits interest units previously issued under a previous LTIP were exchanged for 44,250 Units under the Partnership's LTIP. Vesting under all of the exchanged awards was retroactive to the initial grant date. The awards are considered for all purposes to have been granted under the Partnership's LTIP. In addition, at IPO, certain profits interest units previously issued were converted into 44,451 subordinated units of the Partnership outside of the LTIP. Vesting for the subordinated units is retroactive to the initial grant date. Compensation expense associated with the subordinated units was $0.1 million, $0.1 million and $0.3 million for the years ended December 31, 2016, 2015 and 2014, respectively. The exchange of the phantom profits interest units and the profits interest units resulted in the reversal of the existing equity compensation liability of $0.1 million in the first quarter of 2014 as the new awards were accounted for as equity. The unearned compensation related to the subordinated units at December 31, 2016 was $0.4 million with an average remaining life of 1.0 years.

CYPRESS ENERGY PARTNERS, L.P.

Notes to Consolidated Financial Statements - Continued

12. Related-Party Transactions

Omnibus Agreement

Effective as of the closing of the IPO, we entered into an omnibus agreement with Holdings and other related parties. The omnibus agreement, as amended in February 2015, governs the following matters, among other things:

- our payment of an annual administrative fee in the amount of $4.0 million ($1.0 million per quarter that was pro-rated in 2014 from the IPO date) to Holdings for providing certain partnership overhead services, including certain executive management services by certain officers of our General Partner, and payroll services for substantially all employees required to manage and operate our businesses. This fee also includes the incremental general and administrative expenses we incur as a result of being a publicly traded partnership. For the year ended December 31, 2016, Holdings provided sponsor support to the Partnership by waiving payment of this quarterly administrative fee;

- our right of first offer on Holdings' and its subsidiaries' assets used in, and entities primarily engaged in, providing SWD and other water and environmental services; and

- indemnification of us by Holdings for certain environmental and other liabilities (including income tax liabilities), including events and conditions associated with the operation of assets that occurred prior to the closing of the IPO and our obligation to indemnify Holdings for events and conditions associated with the operation of our assets that occur after the closing of the IPO and for environmental liabilities related to our assets to the extent Holdings is not required to indemnify us.

So long as Holdings controls our General Partner, the omnibus agreement will remain in full force and effect, unless we and Holdings agree to terminate it sooner. If Holdings ceases to control our General Partner, either party may terminate the omnibus agreement, provided that the indemnification obligations will remain in full force and effect in accordance with their terms. We and Holdings may agree to further amend the omnibus agreement; however, amendments that the General Partner determines are adverse to our unitholders will also require the approval of the Conflicts Committee of our Board of Directors.

The amount charged by Holdings under the omnibus agreement for the years ended December 31, 2015 and 2014 was $4.0 million and $3.8 million (2014 amount pro-rated from the IPO date) and is reflected in *general and administrative* in the Consolidated Statements of Operations. As noted above, Holdings provided sponsor support to the Partnership by waiving payment of this fee for the year ended December 31, 2016 and as a result, no payments were made in 2016.

To the extent that Holdings incurs expenses on behalf of the Partnership in excess of administrative expense amounts paid under the omnibus agreement (including executive management services, payroll services, general and administrative costs incurred as a result of being a publicly traded partnership, and other allocated costs), the excess is allocated to the Partnership as non-cash allocated costs. The non-cash allocated amounts are reflected as *general and administrative expenses* in the Consolidated Statement of Operations and as a *contribution attributable to general partner* in the Consolidated Statement of Owners' Equity. These costs are included as a component of *net loss attributable to general partner* in the Consolidated Statements of Operations. Non-cash allocated costs reflected in the Partnership's financial statements were $3.8 million, $0.6 million and $0.5 million, respectively, for the years ended December 31, 2016, 2015 and 2014. The allocation methods utilized in determining the non-cash allocated costs represent a reasonable allocation of costs incurred by Holdings on behalf of the Partnership.

In addition to funding certain general and administrative expenses on our behalf, Holdings provided the Partnership with additional temporary financial support by contributing a total of $2.5 million for the year ended December 31, 2016 in cash, as a reimbursement of certain expenditures incurred by the Partnership. These payments are reflected as a *contribution attributable to general partner* in the Consolidated Statement of Owners' Equity and as a component of the *net loss attributable to the general partner* in the Consolidated Statement of Operations for the year ended December 31, 2016.

CYPRESS ENERGY PARTNERS, L.P.

Notes to Consolidated Financial Statements - Continued

Other Related Party Transactions

A former board member had ownership interests in entities with which the Partnership transacts business including:

Creek Energy Services, LLC (“Creek,” – formerly Rud Transportation, LLC) – Total revenue recognized by the Partnership from Creek while it was considered a related party was $1.1 million and $2.1 million for the years ended December 31, 2015 and 2014, respectively. Accounts receivable from Creek was $0.1 million at December 31, 2015 and is included in *trade accounts receivable, net* in the Consolidated Balance Sheets.

SBG Pipeline SW 3903, LLC (“3903”) – Total revenue recognized by the Partnership from 3903 while it was considered a related party was $0.6 million for the year ended December 31, 2015, prior to the sale of the ownership interest to an unrelated third party effective June 30, 2015. There were no revenues received from 3903 for the year ended December 31, 2014.

Effective June 1, 2015, an affiliate of SBG Energy assigned and transferred its 49% membership interest in Cypress Energy Services, LLC (“CES LLC”) to the Partnership for one dollar (the “CES Transaction”). As a result, the Partnership, as of that date, owns 100% of CES LLC. Because we already controlled and consolidated CES LLC in our Consolidated Financial Statements, the previously recorded non-controlling interest in CES LLC has been reflected in the Consolidated Statement of Owners’ Equity as an increase in equity of $0.9 million for our common and subordinated unitholders.

The CES Transaction was completed in conjunction with another transaction with SBG Energy effective July 1, 2015. On that date, the Partnership waived its rights to purchase and its rights of first refusal related to certain SWD assets pursuant to a previous option agreement with SBG Energy in exchange for $1.0 million. The $1.0 million payment has been reflected in *gain on waiver of right of purchase and other, net* on the Consolidated Statements of Operations for the year ended December 31, 2015.

The Partnership provides management services to a 25% owned company, Alati Arnegard, LLC (“Arnegard”). Management fee revenue earned from Arnegard is included in *revenues* on the Consolidated Statements of Operations and totaled $0.6 million, $0.7 million and $0.6 million for the years ended December 31, 2016, 2015 and 2014, respectively. Accounts receivable from Arnegard totaled $0.1 million at December 31, 2016 and 2015 and is included in *trade accounts receivable, net* on the Consolidated Balance Sheets.

The Partnership outsources staffing and payroll services to an affiliated entity, Cypress Energy Management – Bakken Operations, LLC ("CEM-Brown"). CEM-Brown was owned 49% by SBG Energy. Effective June 1, 2015, Holdings acquired the 49% ownership interest of CEM-Brown and now owns 100% of CEM-Brown. Total employee related costs paid to CEM-Brown prior to the acquisition of the 49% ownership interest on June 1, 2015 were $1.2 million and $3.0 million for the years ended December 31, 2015 and 2014, respectively. There were no staffing or payroll services provided to the Partnership by CEM-Brown in the year ended December 31, 2016. There were no accounts payable due CEM-Brown at December 31, 2016 or 2015.

CYPRESS ENERGY PARTNERS, L.P.

Notes to Consolidated Financial Statements - Continued

13. Commitments and Contingencies

Security Deposits

The Partnership has various performance obligations which are secured with short-term security deposits totaling $0.5 million at December 31, 2016 and 2015. These amounts are included in *prepaid expenses and other* on the Consolidated Balance Sheets.

Employment Contract Commitments

The Partnership has employment agreements with certain executives. The executive employment agreements are effective for a term of three-to-five years from the commencement date, after which time they will continue on an "at-will" basis. These agreements provide for minimum annual compensation, adjusted for annual increases as authorized by the Board of Directors. Certain agreements provide for severance payments in the event of specified termination of employment. At December 31, 2016 and 2015, the aggregate commitment for future compensation and severance was approximately $1.0 million and $1.4 million, respectively.

Compliance Audit Contingencies

Certain customer master service agreements ("MSA's") offer our customers the opportunity to perform periodic compliance audits, which include the examination of the accuracy of our invoices. Should our invoices be determined to be inconsistent with the MSA, or inaccurate, the MSA's may provide the customer the right to receive a credit or refund for any overcharges identified. At any given time, we may have multiple audits ongoing. At December 31, 2016 and 2015, the Partnership had contingent liabilities of $0.1 million associated with the potential settlement of customer audits. The contingent liability is reflected in *accrued payroll and other* on the Consolidated Balance Sheets as of December 31, 2016 and 2015.

Management Service Contracts

The Partnership has historically provided management services for non-owned SWD facilities under contractual arrangements. Principals of two of these management services contract customers (under common control) approached the Partnership about selling their interest in the managed SWD facilities to the Partnership. Due to a number of factors, including the depressed energy economy and the proposed asking price for these facilities, the Partnership was unwilling to enter into a purchase agreement for the facilities. Subsequently, in May 2015, the Partnership was notified by these principals that they were terminating the management contracts related to these two facilities. While management of the Partnership believes that the parties did not have the right to terminate the agreements pursuant to the terms of the agreements, the termination of these agreements resulted in a reduction of management fee revenue and corresponding labor costs associated with staffing the facilities. Management fee revenues related to these contracts totaled \$0.3 million and \$1.5 million for the years ended December 31, 2015 and 2014, respectively, prior to the customer's improper termination of the agreements. After settlement discussions failed, the Partnership commenced litigation proceedings regarding the improper termination of these agreements. In the first quarter of 2017, the parties agreed to a settlement. See *Legal Proceedings*.

Legal Proceedings

On July 3, 2014, a group of former minority shareholders of Tulsa Inspection Resources, Inc. ("TIR Inc.", the predecessor of the TIR Entities), formerly an Oklahoma corporation, filed a civil action in the United States District Court for the Northern District of Oklahoma against TIR LLC, members of TIR LLC, and certain affiliates of TIR LLC's members. TIR LLC is the successor in interest to TIR Inc., resulting from a merger between the entities that closed in December 2013 (the "TIR Merger"). The former shareholders of TIR Inc. claim that they did not receive sufficient value for their shares in the TIR Merger and are seeking rescission of the TIR Merger or, alternatively, compensatory and punitive damages. The Partnership is not named as a defendant in this civil action. We believe that the possibility of the Partnership incurring material losses as a result of this action is remote. In addition, the Partnership anticipates no disruption in its business operations related to this action.

In September 2015, Flatland Resources I, LLC and Flatland Resources II, LLC, two of our management services customers (under common ownership) initiated a civil action in the District Court for the McKenzie County District of the State of North Dakota against CES LLC. The customers claim that CES LLC breached the management agreements and interfered with their business relationships, and seek to rescind the management agreements and recover any damages. The customers initiated this lawsuit upon dismissal from federal court due to lack of jurisdiction of CES LLC's lawsuit against the customers seeking to enforce the management agreements. CES LLC subsequently filed an answer and counterclaims, as well as a third party complaint against the principal of the customers seeking to enforce the management agreements and other injunctive relief, as well as monetary damages. The court subsequently granted CES's motion to transfer venue to the Grand Forks County District Court. In the first quarter of 2017, CES received a cash payment and other consideration and the parties settled the matter and dismissed all associated claims.

Internal Revenue Service Audits

In January 2016, the Partnership received notices from the Internal Revenue Service ("IRS") that conveyed its intent to audit the consolidated income tax return of TIR, Inc. for the 2012 tax year and audit payroll and payroll tax filings of TIR Inc. for the 2013 tax year. The 2013 payroll audit has completed with a no-change letter. Although the TIR, Inc. income tax audit for the 2012 tax year is not yet complete, the Partnership believes, based on correspondence from the IRS, that any adjustments related to this income tax audit should not be material. Additionally, based on the terms of the Partnership's omnibus agreement with Holdings, Holdings would indemnify the Partnership for certain liabilities (including income tax liabilities) associated with the operation of assets that occurred prior to the closing of our IPO should any liabilities arise as a result of these audits. Because of this, the Partnership believes that the possibility of incurring material losses as a result of these IRS audits is remote.

CYPRESS ENERGY PARTNERS, L.P.

Notes to Consolidated Financial Statements - Continued

Leases

The Partnership has entered into land lease agreements on four of its SWD facilities. The leases generally provide for initial terms of 15 – 20 years with renewal options. The Partnership also maintains various office leases in the U.S. and Canada, with its corporate offices in Tulsa, OK. Lease expense under these operating leases was $1.0 million, $0.8 million $0.1 million for the years ended December 31, 2016, 2015 and 2014, respectively.

Minimum annual lease commitments under the current office lease and other operating leases at December 31, 2016 follows:

	(in thousands)	
2017	$	865
2018		151
2019		25
2020		25
2021		25
Thereafter		507
Total	$	1,598

14. Segment Disclosures

The Partnership's operations consist of three reportable segments: (i) Pipeline Inspection Services ("PIS"), (ii) Integrity Services ("IS") and (iii) Water and Environmental Services ("W&ES"). In conjunction with the Brown acquisition (Note 3) in the second quarter of 2015, we created the IS segment. The economic characteristics of Brown were sufficiently dissimilar from our existing Pipeline Inspection and Integrity Services segment resulting in the creation of a new segment. As a result, the Pipeline Inspection and Integrity Services segment was renamed Pipeline Inspection Services.

PIS – This segment represents our pipeline inspection services operations. We aggregate these operating entities for reporting purposes as they have similar economic characteristics, including centralized management and processing. This segment provides independent inspection and integrity services to various energy, public utility and pipeline companies. The inspectors in this segment perform a variety of inspection services on midstream pipelines, gathering systems and distribution systems, including data gathering and supervision of third-party construction, inspection and maintenance and repair projects. Our results in this segment are driven primarily by the number and type of inspectors performing services for customers and the fees charged for those services, which depend on the nature and duration of the project.

IS – This segment includes the acquired operations of Brown (Note 3). This segment provides independent hydro-testing integrity services to major natural gas and petroleum pipeline companies, as well as pipeline construction companies located throughout the United States. Field personnel in this segment primarily perform hydrostatic testing on newly constructed and existing natural gas and petroleum pipelines. Results in this segment are driven primarily by field personnel performing services for customers and the fees charged for those services, which depend on the nature, scope and duration of the project.

W&ES – This segment includes the operations of ten SWD facilities, fees related to the management of third party SWD facilities, as well as an equity ownership in one managed facility. We aggregate these operating entities for reporting purposes as they have similar economic characteristics and have centralized management and processing. Segment results are driven primarily by the volumes of produced water and flowback water we inject into our SWD facilities and the fees we charge for our services. These fees are charged on a per barrel basis and vary based on the quantity and type of saltwater disposed, competitive dynamics and operating costs. In addition, for minimal marginal cost, we generate revenue by selling residual oil we recover from the disposed water.

Other – These amounts represent corporate and overhead items not specifically allocable to the other reportable segments.

CYPRESS ENERGY PARTNERS, L.P.

Notes to Consolidated Financial Statements - Continued

The following table outlines segment operating income and a reconciliation of total segment operating income to net income before income tax expense.

	PIS	IS	W&ES	Other	Total
	(in thousands)				
Year ended December 31, 2016					
Revenue	$275,171	$13,884	$8,942	$—	$297,997
Costs of services	247,214	11,542	3,761	—	262,517
Gross margin	27,957	2,342	5,181	—	35,480
General and administrative	12,521	2,829	1,866	4,637 (a)	21,853
Depreciation, amortization and accretion	2,439	658	1,764	—	4,861
Impairments	—	8,411	2,119	—	10,530
Operating income (loss)	$12,997	$(9,556)	$(568)	$(4,637)	(1,764)
Interest expense, net					(6,559)
Other, net					356
Net loss before income tax expense					$(7,967)

(a) Amount includes $3.8 million that Holdings could have charged the Partnership under the omnibus agreement. Since Holdings elected to waive this omnibus fee for the year ended December 31, 2016, none of this expense is reflected in the operating results of the individual segments.

	PIS	IS	W&ES	Other	Total
Year ended December 31, 2015					
Revenue	$341,929	$14,614	$14,648	$—	$371,191
Costs of services	309,584	10,398	6,279	—	326,261
Gross margin	32,345	4,216	8,369	—	44,930
General and administrative	16,672	2,490	3,351	1,282 (b)	23,795
Depreciation, amortization and accretion	2,512	421	2,494	—	5,427
Impairments	—	—	6,645	—	6,645
Operating income (loss)	$13,161	$1,305	$(4,121)	$(1,282)	9,063
Interest expense, net					(5,656)
Gain on waiver of right of purchase and other, net					1,136
Net loss before income tax expense					$4,543

(b) Amount includes $0.6 million of expenses incurred by Holdings in excess of the omnibus fee.

Year ended December 31, 2014

Revenue	$382,002	$—	$22,416	$—	$404,418
Costs of services	346,738	—	8,617	—	355,355
Gross margin	35,264	—	13,799	—	49,063
General and administrative	17,734	—	3,090	497	21,321
Depreciation, amortization and accretion	2,539	—	3,806	—	6,345
Impairments	—	—	32,546	—	32,546
Operating income (loss)	$14,991	$—	$(25,643)	$(497)	(11,149)
Interest expense, net					(3,208)
Offering costs					(446)
Other, net					92
Net loss before income tax expense					$(14,711)

Total Assets

December 31, 2016	$124,840	$12,079	$38,141	$(7,548)	$167,512
December 31, 2015 (as adjusted)	$130,623	$23,097	$38,418	$(1,256)	$190,882

CYPRESS ENERGY PARTNERS, L.P.

Notes to Consolidated Financial Statements – Continued

15. Distributions

The following table summarizes the cash distributions declared and paid by the Partnership since our IPO.

Payment Date	Per Unit Cash Distributions	Total Cash Distributions	Total Cash Distributions to Affiliates (a)
		(in thousands)	
May 15, 2014 (b)	$ 0.301389	$ 3,565	$ 2,264
August 14, 2014	0.396844	4,693	2,980
November 14, 2014	0.406413	4,806	3,052
Total 2014 Distributions	1.104646	13,064	8,296
February 14, 2015	0.406413	4,806	3,052
May 14, 2015	0.406413	4,808	3,053
August 14, 2015	0.406413	4,809	3,087
November 13, 2015	0.406413	4,809	3,092
Total 2015 Distributions	1.625652	19,232	12,284
February 12, 2016	0.406413	4,810	3,107
May 13, 2016	0.406413	4,812	3,099
August 12, 2016	0.406413	4,817	3,103
November 14, 2016	0.406413	4,819	3,105
Total 2016 Distributions	1.625652	19,258	12,414
February 13, 2017 (c)	0.406413	4,823	3,107
Total Distributions (through February 13, 2017 since IPO)	$ 4.762363	$ 56,377	$ 36,101

(a) Approximately 64.3% of the Partnership's outstanding units at December 31, 2016 were held by affiliates.
(b) Distribution was pro-rated from the date of our IPO through March 31, 2014.
(c) Fourth quarter 2016 distribution was declared and paid in the first quarter of 2017.

16. Subsequent Events

Canadian Subsidiary

In early 2017, the largest customer of our Canadian subsidiary (PIS segment) completed a bid process and selected different service providers for its major projects (we continue to perform certain services for this customer, such as integrity services). During the year ended December 31, 2016, pipeline inspection services to this customer accounted for approximately $25.0 million of revenue and $1.7 million of gross margin, which represented approximately 81% of the revenues and 81% of the gross margin of our Canadian operations (and approximately 8.4% of our consolidated revenues and 4.9% of our consolidated gross margin for the year ended December 31, 2016).

Our Consolidated Balance Sheet at December 31, 2016 includes customer relationship intangible assets with a net book value of $1.2 million and trade names with a net book value of $0.2 million that were initially recorded upon the acquisition of the Canadian business. Given the change in circumstances, we will evaluate these intangible assets for impairment, and may record impairments on these intangible assets in the three months ending March 31, 2017.

In addition, our Consolidated Balance Sheet at December 31, 2016 includes $2.5 million of accumulated other comprehensive losses associated with currency translation adjustments, all of which relate to our Canadian subsidiary. A portion of this balance relates to U.S.-dollar denominated intercompany payables from our Canadian subsidiary to U.S.-based entities within our consolidated group of entities. We have reported our Canadian subsidiary's currency translation losses on these intercompany balances to other comprehensive income (as translation adjustments), rather than as a reduction to net income (as translation losses), based on the intent that our investment in Canada (including intercompany loans) has been considered a long-term investment. Given the change in circumstances, in March of 2017, we have begun to evaluate our options related to the future of this subsidiary. It is possible that, during 2017, we may reclassify some or all of the $2.5 million balance in accumulated other comprehensive loss to Partners' Capital, which would be reported in the Consolidated Statement of Operations as a reduction to net income.

Orla Lightning Strike and Fire

In January 2017, a lightning strike at our Orla SWD facility initiated a fire that effectively destroyed the surface equipment at the facility. Due to the aftereffects of the fire, we were required to perform some environmental remediation and reclamation at the facility. All appropriate governmental agencies were contacted and informed of our remediation procedures. Temporary operations were established within 11 days of the incident in order to minimize the disruption of business at this facility. We are currently working with our insurance providers to complete remediation and reconstruct the SWD facility (we have minimal deductibles related to our pollution and property coverage at this facility). Currently, we anticipate that the facility will be rebuilt by the third quarter of 2017.

Subordination

Effective February 14, 2017, with the payment of the fourth quarter distribution and the fulfillment of other requirements associated with the termination of the subordination period, the Partnership emerged from subordination, therefore converting the subordinated units to common units at that time.

17. Condensed Consolidating Financial Information

The following financial information reflects consolidating financial information of the Partnership and its wholly owned guarantor subsidiaries and non-guarantor subsidiaries for the periods indicated. The information is presented in accordance with the requirements of Rule 3-10 under the SEC's Regulation S-X. The financial information may not necessarily be indicative of financial position, results of operations or cash flows had the guarantor subsidiaries or non-guarantor subsidiaries operated as independent entities. The Partnership has not presented separate financial and narrative information for each of the guarantor subsidiaries or non-guarantor subsidiaries because it believes such financial and narrative information would not provide any additional relative information that would be material in evaluating the sufficiency of the guarantor subsidiaries and non-guarantor subsidiaries. The Partnership anticipates issuing debt securities that will be fully and unconditionally guaranteed by the guarantor subsidiaries. These debt securities will be jointly and severally guaranteed by the guarantor subsidiaries. There are no restrictions on the Partnership's ability to obtain cash dividends or other distributions of funds from the guarantor subsidiaries.

The presentation of our Consolidating Balance Sheet as of December 31, 2015, our Consolidating Statement of Comprehensive Income (Loss) for the years ended December 31, 2015 and 2014, and our Consolidating Statement of Cash Flows for the year ended December 31, 2015 and 2014 have been updated to reflect adjustments between the Guarantors and Eliminations. These adjustments have (i) reduced the Guarantors' *notes receivable - affiliates* and total *partners' capital* and the Parent's investment in the Guarantors and the total *partners' capital* by $1.0 million, with the offset to Eliminations on the Consolidating Balance Sheet; (ii) reduced the Guarantor's *comprehensive income* by $0.6 million and '0.3 million for the year ended December 31, 2015 and 2014, respectively, with the offset to Eliminations on the Consolidating Statement of Comprehensive Income (Loss) and (iii) adjusted various offsetting items in working capital for the Guarantors and Eliminations in the Consolidating Statement of Cash Flows. These changes have had no impact on the consolidated results as previously reported.

Consolidating Balance Sheet
As of December 31, 2016
(in thousands)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$695	$ 20,251	$ 5,747	$ —	$ 26,693
Trade accounts receivable, net	—	33,046	6,125	(689)	38,482
Accounts receivable - affiliates	—	12,622	—	(12,622)	—
Prepaid expenses and other	—	996	46	—	1,042
Total current assets	695	66,915	11,918	(13,311)	66,217
Property and equipment:					
Property and equipment, at cost	—	19,366	3,093	—	22,459
Less: Accumulated depreciation	—	6,798	1,042	—	7,840
Total property and equipment, net	—	12,568	2,051	—	14,619
Intangible assets, net	—	23,875	5,749	—	29,624
Goodwill	—	53,914	2,989	—	56,903
Investment in subsidiaries	29,454	(417)	—	(29,037)	—
Notes receivable - affiliates	—	13,662	—	(13,662)	—
Other assets	—	139	10	—	149
Total assets	$30,149	$ 170,656	$ 22,717	$ (56,010)	$ 167,512
LIABILITIES AND OWNERS' EQUITY					
Current liabilities:					
Accounts payable	$—	$ 1,653	$ 712	$ (675)	$ 1,690
Accounts payable - affiliates	8,860	—	5,400	(12,622)	1,638
Accrued payroll and other	15	7,082	503	(15)	7,585
Income taxes payable	—	967	44	—	1,011
Total current liabilities	8,875	9,702	6,659	(13,312)	11,924
Long-term debt	(1,201)	131,400	5,500	—	135,699
Notes payable - affiliates	—	—	13,662	(13,662)	—
Deferred tax liabilities	—	8	354	—	362
Asset retirement obligations	—	139	—	—	139
Total liabilities	7,674	141,249	26,175	(26,974)	148,124
Commitments and contingencies - Note 13					
Owners' equity:					
Total partners' capital	17,425	24,357	(3,458)	(23,986)	14,338
Non-controlling interests	5,050	5,050	—	(5,050)	5,050
Total owners' equity	22,475	29,407	(3,458)	(29,036)	19,388
Total liabilities and owners' equity	$30,149	$ 170,656	$ 22,717	$ (56,010)	$ 167,512

Consolidating Balance Sheet
As of December 31, 2015
(as adjusted - in thousands)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$378	$ 19,570	$ 4,202	$ —	$ 24,150
Trade accounts receivable, net	—	40,029	8,289	(53)	48,265
Accounts receivable - affiliates	—	5,601	—	(5,601)	—
Prepaid expenses and other	—	2,078	286	(35)	2,329
Total current assets	378	67,278	12,777	(5,689)	74,744
Property and equipment:					
Property and equipment, at cost	—	20,790	2,916	—	23,706
Less: Accumulated depreciation	—	4,941	428	—	5,369
Total property and equipment, net	—	15,849	2,488	—	18,337
Intangible assets, net	—	26,135	6,351	—	32,486
Goodwill	—	53,914	11,359	—	65,273
Investment in subsidiaries	42,034	10,465	—	(52,499)	—
Notes receivable - affiliates	—	13,527	—	(13,527)	—
Other assets	—	32	10	—	42
Total assets	$42,412	$ 187,200	$ 32,985	$ (71,715)	$ 190,882
LIABILITIES AND OWNERS' EQUITY					
Current liabilities:					
Accounts payable	$6	$ 467	$ 1,732	$ —	$ 2,205
Accounts payable - affiliates	1,237	912	4,042	(5,278)	913
Accrued payroll and other	—	6,855	293	(53)	7,095
Income taxes payable	—	385	—	(35)	350
Total current liabilities	1,243	8,619	6,067	(5,366)	10,563
Long-term debt	(1,771)	135,400	5,500	—	139,129
Notes payable - affiliates	—	—	13,850	(13,850)	—
Deferred tax liabilities	—	43	328	—	371
Asset retirement obligations	—	117	—	—	117
Total liabilities	(528)	144,179	25,745	(19,216)	150,180
Commitments and contingencies					
Owners' equity:					
Total partners' capital	32,967	33,048	7,240	(42,526)	30,729
Non-controlling interests	9,973	9,973	—	(9,973)	9,973
Total owners' equity	42,940	43,021	7,240	(52,499)	40,702
Total liabilities and owners' equity	$42,412	$ 187,200	$ 32,985	$ (71,715)	$ 190,882

Consolidating Statement of Operations
For the Year Ended December 31, 2016
(in thousands)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
Revenues	$—	$ 252,955	$ 58,694	$ (13,652)	$ 297,997
Costs of services	—	222,067	54,102	(13,652)	262,517
Gross margin	—	30,888	4,592	—	35,480
Operating costs and expense:					
General and administrative	4,637	12,625	4,591	—	21,853
Depreciation, amortization and accretion	—	4,091	770	—	4,861
Impairments	—	2,119	8,411	—	10,530
Operating (loss)	(4,637)	12,053	(9,180)	—	(1,764)
Other income (expense):					
Equity earnings (loss) in subsidiaries	862	(10,020)	—	9,158	—
Interest expense, net	(889)	(4,854)	(816)	—	(6,559)
Other, net	—	334	22	—	356
Net income (loss) before income tax expense	(4,664)	(2,487)	(9,974)	9,158	(7,967)
Income tax expense	—	1,150	45	—	1,195
Net income (loss)	(4,664)	(3,637)	(10,019)	9,158	(9,162)
Net (loss) attributable to non-controlling interests	—	(4,499)	—	—	(4,499)
Net income (loss) attributable to partners / controlling interests	(4,664)	862	(10,019)	9,158	(4,663)
Net (loss) attributable to general partner	(6,298)	—	—	—	(6,298)
Net income (loss) attributable to limited partners	$ 1,634	$ 862	$ (10,019)	$ 9,158	$ 1,635

Consolidating Statement of Operations
For the Year Ended December 31, 2015
(in thousands)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
Revenues	$—	$ 329,086	$ 54,708	$ (12,603)	$ 371,191
Costs of services	—	290,524	48,340	(12,603)	326,261
Gross margin	—	38,562	6,368	—	44,930
Operating costs and expense:					
General and administrative	1,282	18,180	4,333	—	23,795
Depreciation, amortization and accretion	—	4,832	595	—	5,427
Impairments	—	6,645	—	—	6,645
Operating income (loss)	(1,282)	8,905	1,440	—	9,063
Other income (expense):					
Equity earnings in subsidiaries	6,115	1,010	—	(7,125)	—
Interest expense, net	(902)	(4,115)	(639)	—	(5,656)
Other, net	—	1,116	20	—	1,136
Net income (loss) before income tax expense	3,931	6,916	821	(7,125)	4,543
Income tax expense	—	372	80	—	452
Net income (loss)	3,931	6,544	741	(7,125)	4,091
Net income (loss) attributable to non-controlling interests	143	429	—	27	599
Net income (loss) attributable to partners / controlling interests	3,788	6,115	741	(7,152)	3,492
Net (loss) attributable to general partner	(648)	—	—	—	(648)
Net income (loss) attributable to limited partners	$4,436	$ 6,115	$ 741	$ (7,152)	$ 4,140

108

Consolidating Statement of Operations
For the Year Ended December 31, 2014
(in thousands)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
Revenues	$—	$ 370,081	$ 34,337	$ —	$ 404,418
Costs of services	—	323,821	31,534	—	355,355
Gross margin	—	46,260	2,803	—	49,063
Operating costs and expense:					
General and administrative	—	19,257	2,064	—	21,321
Depreciation, amortization and accretion	—	6,136	209	—	6,345
Impairments	—	32,546	—	—	32,546
Operating income (loss)	—	(11,679)	530	—	(11,149)
Other income (expense):					
Equity earnings in subsidiaries	(14,134)	—	—	14,134	—
Interest expense, net	(983)	(1,892)	(333)	—	(3,208)
Offering costs, net	(446)	—	—	—	(446)
Other, net	—	84	8	—	92
Net income (loss) before income tax expense	(15,563)	(13,487)	205	14,134	(14,711)
Income tax expense	—	356	112	—	468
Net income (loss)	(15,563)	(13,843)	93	14,134	(15,179)
Net income (loss) attributable to non-controlling interests	4,646	291	—	36	4,973
Net income (loss) attributable to partners / controlling interests	(20,209)	(14,134)	93	14,098	(20,152)
Net income attributable to general partner	149	—	—	—	149
Net income (loss) attributable to limited partners	$ (20,358)	$ (14,134)	$ 93	$ 14,098	$ (20,301)

Consolidating Statement of Comprehensive Income (Loss)
For the Year Ended December 31, 2016
(in thousands)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
Net income (loss)	$(4,664)	$ (3,637)	$ (10,019)	$ 9,158	$ (9,162)
Other comprehensive income - Foreign currency translation	—	71	182	—	253
Comprehensive income (loss)	$(4,664)	$ (3,566)	$ (9,837)	$ 9,158	$ (8,909)
Comprehensive (loss) attributable to non-controlling interests	—	(4,499)	—	—	(4,499)
Comprehensive (loss) attributable to general partner	(6,298)	—	—	—	(6,298)
Comprehensive income (loss) attributable to limited partners	$1,634	$ 933	$ (9,837)	$ 9,158	$ 1,888

Consolidating Statement of Comprehensive Income (Loss)
For the Year Ended December 31, 2015
(in thousands)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
Net income (loss)	$3,931	$ 6,544	$ 741	$ (7,125)	$ 4,091
Other comprehensive income - Foreign currency translation	—	(564)	(1,178)	-	(1,742)
Comprehensive income (loss)	$3,931	$ 5,980	$ (437)	$ (7,125)	$ 2,349
Comprehensive (loss) attributable to non-controlling interests	143	429	—	(430)	142
Comprehensive (loss) attributable to general partner	(648)	—	—	—	(648)
Comprehensive income (loss) attributable to limited partners	$4,436	$ 5,551	$ (437)	$ (6,695)	$ 2,855

Consolidating Statement of Comprehensive Income (Loss)
For the Year Ended December 31, 2014
(in thousands)

	Parent	Guarantors		Eliminations	Consolidated

			Non-Guarantors		
Net income (loss)	$(15,563)	$(13,843)	$ 93	$ 14,134	$ (15,179)
Other comprehensive income - Foreign currency translation	—	(316)	(621)	—	(937)
Comprehensive income (loss)	$(15,563)	$(14,159)	$ (528)	$ 14,134	$ (16,116)
Comprehensive (loss) attributable to non-controlling interests	4,646	291	—	(279)	4,658
Comprehensive income attributable to general partner	149	—	—	—	149
Comprehensive income (loss) attributable to limited partners	$(20,358)	$(14,450)	$ (528)	$ 14,413	$ (20,923)

110

Consolidating Statement of Cash Flows
For the Year Ended December 31, 2016
(in thousands)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
Operating activities:					
Net income (loss)	$(4,664)	$(3,637)	$(10,019)	$ 9,158	$ (9,162)
Adjustments to reconcile net income (loss) to cash provided by (used in) operating activities:					
Depreciation, amortization and accretion	—	4,495	1,293	—	5,788
Impairments	—	2,119	8,411	—	10,530
Gain (loss) on asset disposal	—	(12)	(7)	—	(19)
Interest expense from debt issuance cost amortization	570	—	—	—	570
Equity-based compensation expense	1,086	—	—	—	1,086
Equity in earnings of investee	—	(309)	—	—	(309)
Distributions from investee	—	200	—	—	200
Equity earnings in subsidiaries	(862)	10,020	—	(9,158)	—
Deferred tax benefit, net	—	(35)	11	—	(24)
Non-cash allocated expenses	3,798	—	—	—	3,798
Changes in assets and liabilities:					
Trade accounts receivable	—	6,983	2,252	636	9,871
Receivables from affiliates	—	(7,021)	—	7,021	—
Prepaid expenses and other	—	941	308	101	1,350
Accounts payable and accrued payroll and other	7,632	507	132	(7,793)	478
Income taxes payable	—	582	45	35	662
Net cash provided by (used in) operating activities	7,560	14,833	2,426	—	24,819
Investing activities:					
Proceeds from fixed asset disposals	—	26	20	—	46
Purchases of property and equipment	—	(1,066)	(310)	—	(1,376)
Net cash used in investing activities	—	(1,040)	(290)	—	(1,330)
Financing activities:					
Repayments of long-term debt	—	(4,000)	—	—	(4,000)
Taxes paid related to net share settlement of equity-based compensation	(107)	—	—	—	(107)
Contributions from general partner	2,500	—	—	—	2,500
Distributions from subsidiaries	9,622	(9,239)	(383)	—	—
Distributions to limited partners	(19,258)	—	—	—	(19,258)
Distributions to non-controlling members	—	—	(424)	—	(424)
Net cash provided by (used in) financing activities	(7,243)	(13,239)	(807)	—	(21,289)
Effects of exchange rates on cash	—	127	216	—	343

Net increase (decrease) in cash and cash equivalents	317	681	1,545	—	2,543
Cash and cash equivalents, beginning of period	378	19,570	4,202	—	24,150
Cash and cash equivalents, end of period	$695	$ 20,251	$ 5,747	$ —	$ 26,693

111

Consolidating Statement of Cash Flows
For the Year Ended December 31, 2015
(in thousands)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
Operating activities:					
Net income (loss)	$3,931	$6,544	$741	$(7,125)	$4,091
Adjustments to reconcile net income (loss) to cash provided by (used in) operating activities:					
Depreciation, amortization and accretion	—	5,102	902	—	6,004
Impairments	—	6,645	—	—	6,645
Loss on asset disposals	—	—	(1)	—	(1)
Interest expense from debt issuance cost amortization	547	—	—	—	547
Equity-based compensation expense	1,167	—	—	—	1,167
Equity in earnings of investee	—	(102)	—	—	(102)
Distributions from investee	—	100	—	—	100
Equity earnings in subsidiaries	(6,115)	(1,010)	—	7,125	—
Deferred tax benefit, net	—	58	(90)	—	(32)
Non-cash allocated expenses	648	—	—	—	648
Changes in assets and liabilities:					
Trade accounts receivable	—	9,540	(546)	45	9,039
Receivables from affiliates	22	3,208	—	(3,230)	—
Prepaid expenses and other	—	267	(69)	35	233
Accounts payable and accrued payroll and other	1,203	(1,074)	(4,536)	3,185	(1,222)
Income taxes payable	—	(122)	(39)	(35)	(196)
Net cash provided by (used in) operating activities	1,403	29,156	(3,638)	—	26,921
Investing activities:					
Proceeds from disposals of property and equipment	—	2	—	—	2
Cash paid for acquisition of 49.9% interest in the TIR Entities	—	(52,588)	—	—	(52,588)
Cash paid for acquisition of 51% of Brown Integrity, LLC, net of cash acquired of $175	—	(10,436)	—	—	(10,436)
Purchases of property and equipment	—	(1,607)	(250)	—	(1,857)
Net cash (used in) investing activities	—	(64,629)	(250)	—	(64,879)
Financing activities:					
Advances on long-term debt	—	63,300	5,500	—	68,800
Repayments of long-term debt	—	(5,500)	—	—	(5,500)
Distributions from subsidiaries	17,225	(17,225)	—	—	—
Distributions to limited partners	(19,232)	—	—	—	(19,232)
Distributions to non-controlling members	—	(1,567)	—	—	(1,567)
Net cash provided by (used in) financing activities	(2,007)	39,008	5,500	—	42,501
Effects of exchange rates on cash	—	(563)	(587)	—	(1,150)

Net increase (decrease) in cash and cash equivalents	(604)	2,972	1,025	—	3,393
Cash and cash equivalents, beginning of period	982	16,598	3,177	—	20,757
Cash and cash equivalents, end of period	$378	$ 19,570	$ 4,202	$ —	$ 24,150
Non-cash items:					
Accrued capital expenditures	$—	$ 6	$ 94	$ —	$ 100

112

Consolidating Statement of Cash Flows
For the Year Ended December 31, 2014
(in thousands)

	Parent	Guarantors	Non-Guarantors	Eliminations	Consolidated
Operating activities:					
Net income (loss)	$(15,563)	$(13,843)	$93	$14,134	$(15,179)
Adjustments to reconcile net income (loss) to cash provided by (used in) operating activities:					
Depreciation, amortization and accretion	—	6,304	209	—	6,513
Impairments	—	32,546	—	—	32,546
Loss on asset disposals	—	3	—	—	3
Interest expense from debt issuance cost amortization	714	—	—	—	714
Equity-based compensation expense	785	—	—	—	785
Equity in earnings of investee	—	(46)	—	—	(46)
Distributions from investee	—	55	—	—	55
Equity earnings in subsidiaries	14,134	—	—	(14,134)	—
Deferred tax benefit, net	—	(22)	9	—	(13)
Non-cash allocated expenses	—	497	—	—	497
Changes in assets and liabilities:					
Trade accounts receivable	—	4,115	2,527	8	6,650
Receivables from affiliates	(22)	(9,604)	795	8,831	—
Prepaid expenses and other	(285)	(248)	(400)	—	(933)
Accounts payable and accrued payroll and other	21	6,513	(659)	(8,839)	(2,964)
Income taxes payable	—	(14,481)	(1,131)	—	(15,612)
Net cash provided by (used in) operating activities	(216)	11,789	1,443	—	13,016
Investing activities:					
Acquisitions of businesses	—	(1,769)	—	—	(1,769)
Purchases of property and equipment	—	(483)	(34)	—	(517)
Net cash (used in) investing activities	—	(2,252)	(34)	—	(2,286)
Financing activities:					
Proceeds from initial public offering	80,213	—	—	—	80,213
Distribution of initial public offering proceeds to Cypress Energy Holdings, LLC	(80,213)	—	—	—	(80,213)
Payment of offering costs	(314)	—	—	—	(314)
Advances on long-term debt	—	7,600	—	—	7,600
Repayments of long-term debt	—	(5,000)	—	—	(5,000)
Payment of debt issuance costs	—	(883)	—	—	(883)
Distributions to members prior to IPO	(279)	111	—	—	(168)
Contribution from general partner	314	168	—	—	482
Distributions from subsidiaries	14,541	(14,541)	—	—	—
Distributions to limited partners	(13,064)	—	—	—	(13,064)

Distributions to non-controlling members	—	(4,683)	—	—	(4,683)
Net cash provided by (used in) financing activities	1,198	(17,228)	—	—	(16,030)
Effects of exchange rates on cash	—	(317)	(316)	—	(633)
Net increase (decrease) in cash and cash equivalents	982	(8,008)	1,093	—	(5,933)
Cash and cash equivalents, beginning of period	—	24,606	2,084	—	26,690
Cash and cash equivalents, end of period	$982	$16,598	$3,177	$—	$20,757
Non-cash items:					
Accrued capital expenditures	$—	$756	$—	$—	$756

113

CYPRESS ENERGY PARTNERS, L.P.

Notes to Consolidated Financial Statements - Continued

18. Quarterly Financial Information (Unaudited)

The following table sets forth certain unaudited financial data for each quarter during 2016 and 2015. The unaudited quarterly information includes all normal recurring adjustments that we consider necessary for a fair presentation of the information shown.

2016	Quarter Ended, (in thousands, except per unit amounts)			
	March 31	June 30	September 30	December 31
Revenues	$73,474	$72,311	$ 81,806	$ 70,406
Gross margin	7,760	7,365	9,926	10,429
Impairments	—	10,530	—	—
Net income (loss)	(1,361)	(11,616)	1,998	1,817
Net income (loss) attributable to partners / controlling interests	(994)	(7,004)	1,917	1,418
Net income (loss) per common limited partner unit - basic	(0.00)	(0.34)	0.28	0.20
Net income (loss) per common limited partner unit - diluted	(0.00)	(0.34)	0.27	0.19
Net income (loss) per subordinated limited partner unit - basic and diluted	(0.00)	(0.34)	0.28	0.20

Revenues and gross margin for the quarter ended December 31, 2016 include $1.2 million related to a price increase on work we performed during preceding quarters. We recognized this revenue upon receipt during the fourth quarter of a signed contract formally evidencing the customer's agreement to the new pricing.

2015	Quarter Ended, (in thousands, except per unit amounts)			
	March 31	June 30	September 30	December 31
Revenues	$94,066	$90,953	$ 96,408	$ 89,764
Gross margin	10,549	10,763	12,101	11,517
Impairments	—	—	5,567	1,078
Net income (loss)	2,826	1,859	(1,640)	1,046
Net income (loss) attributable to partners / controlling interests	2,659	1,936	(1,809)	706

Net income (loss) per common limited partner unit - basic and diluted	0.22	0.18	(0.15)	0.10
Net income (loss) per subordinated limited partner unit - basic and diluted	0.22	0.18	(0.15)	0.10

114

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of 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 the principal executive officer and principal financial officer of our general partner, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) or Rule 15d-15(e) under the Exchange Act) as of the end of the period covered by this Annual Report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including the principal executive officer and principal financial officer of our general partner, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, the principal executive officer and principal financial officer of our general partner have concluded that our disclosure controls and procedures were effective at the reasonable assurance level as of December 31, 2016. Additionally, we have implemented a quarterly sub-certification process whereby all members of upper management and certain other management will review our filings and confirm their responsibility for, among other things, the effectiveness of key controls in their functional areas and that they are unaware of inaccuracies or omissions in our financial statements.

Our management, including our principal executive officer and principal financial officer, does not expect that our disclosure controls or our internal controls over financial reporting (“Internal Controls”) will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. 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. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the Partnership have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that simple errors or mistakes can occur. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based, in part, upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Over time, controls may become inadequate because of changes in conditions, or the degree of compliance with the policies or procedures may deteriorate. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our disclosure controls and internal controls and make modifications as necessary; our intent in this regard is that the disclosure controls and the internal controls will be maintained as systems change and conditions warrant.

Management’s Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate and effective internal control over financial reporting, as such term is defined under Exchange Act Rule 13a-15(f). Our internal control over financial reporting is a process that is designed under the supervision of our Chief Executive Officer and Chief Financial Officer, and effected by our Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. Our internal control over financial reporting includes those policies and procedures that:

i. pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets;

ii. provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP, and that receipts and expenditures recorded by us are being made only in accordance with authorizations of our management and Board of Directors; and

iii. provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on our 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 and procedures may deteriorate.

The internal controls are supported by written processes and complemented by a staff of competent business process owners, as well as competent and qualified external resources used to assist in testing the operating effectiveness of the internal control over financial reporting.

Management has conducted its evaluation of the effectiveness of internal control over financial reporting as of December 31, 2016, based on the framework in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Management's assessment included an evaluation of the design of our internal control over financial reporting and testing the operational effectiveness of our internal control over financial reporting. Management reviewed the results of the assessment with the Audit Committee of the Board of Directors. Based on its assessment and review with the Audit Committee, management concluded that, at December 31, 2016, we maintained effective internal control over financial reporting, and management believes that we have no material internal control weaknesses in our financial reporting process.

Attestation Report of the Registered Public Accounting Firm

Pursuant to the Jumpstart Our Business ("JOBS") Act enacted in 2012, our independent registered public accounting firm will not be required to attest to the effectiveness of our internal control over financial reporting pursuant to Section 404 of the Sarbanes-Oxley Act of 2002 for up to five years or through such earlier date that we are no longer an "emerging growth company" as defined in the JOBS Act.

Changes in Internal Control over Financial Reporting

Beginning January 1, 2016, the Partnership initiated implementation of a new enterprise resource planning ("ERP") accounting and reporting system designed to improve the timeliness and quality of information (including financial information) to all appropriate levels of Partnership personnel. This new ERP system was not implemented in response to any material weakness in the Partnership's internal control over financial reporting. The implementation of this software occurred in phases during 2016 and will continue into the 2017 year. The implementation of the ERP system has affected the processes that constitute our internal control over financial reporting and requires ongoing testing for effectiveness. The adoption of this new ERP system has not materially affected our internal controls over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

MANAGEMENT

Management of Cypress Energy Partners, L.P.

We are managed by the executive officers of our general partner. Our general partner is not elected by our unitholders and will not be subject to re-election by our unitholders in the future. Holdings indirectly owns all of the membership interests in our general partner. Our general partner has a board of directors, and our unitholders are not entitled to elect the directors or directly or indirectly participate in our management or operations. Our general partner will be liable, as general partner, for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made specifically nonrecourse to it. Whenever possible, we intend to incur indebtedness that is nonrecourse to our general partner.

Our general partner currently has five directors. Holdings will appoint all members to the board of directors of our general partner. Pursuant to our general partner's operating agreement, Holdings appointed to our board of directors (i) Peter C. Boylan III, who has the right to serve as a director as long as CEP Capital Partners, LLC, an entity controlled by Mr. Boylan, is a member of Holdings and (ii) such other individuals selected by Mr. Boylan that, together with Mr. Boylan, constitute a percentage of the board of directors equal to the percentage of Holdings that CEP Capital Partners, LLC owns. In his exercise of this right, Mr. Boylan has appointed himself and may appoint others to the board. We have three independent directors who qualify for service on the audit committee. Our board of directors has determined that Henry Cornell, John T. McNabb II, and Stanley A. Lybarger are independent under the independence standards of the NYSE and eligible for service on the audit committee. Despite the fact that Mr. Cornell beneficially owns 2.0% of Holdings, which together with its controlled affiliates owns approximately 58.8% of our outstanding limited partner interests, the board of directors determined he is independent in that he does not have a current relationship with us that would interfere with the exercise of his independent judgment in carrying out his responsibilities as a director.

Our general partner has the sole responsibility for providing the employees and other personnel necessary to conduct our operations. All of the employees that conduct our business are employed by affiliates of our general partner, but we sometimes refer to these individuals in this report as our employees. Employees of the TIR Entities were transferred to an affiliate of our general partner subsequent to the closing of our IPO.

Director Independence

Although most companies listed on the NYSE are required to have a majority of independent directors serving on the board of directors of the listed company, the NYSE does not require a publicly traded limited partnership like us to have a majority of independent directors on the board of directors of our general partner, or to establish a compensation or a nominating and corporate governance committee. All of our audit committee members are required to meet the independence and financial literacy tests established by the NYSE and the Exchange Act.

Committees of the Board of Directors

The board of directors of our general partner has an audit committee and a conflicts committee, and may have such other committees as the board of directors shall determine from time to time. Each of the standing committees of the board of directors will have the composition and responsibilities described below.

Audit Committee

Our general partner has an audit committee comprised of three directors who each meet the independence and experience standards established by the NYSE and the Exchange Act. Henry Cornell, John T. McNabb II, and Stanley A. Lybarger serve as members of our audit committee. Mr. Lybarger began serving as Chairman of the audit committee upon his appointment on March 5, 2014. Mr. McNabb served as Chairman prior to that date. Our board of directors has determined that Mr. Lybarger and Mr. McNabb each have such accounting or related financial management expertise sufficient to qualify as an audit committee financial expert in accordance with Item 407(d) of Regulation S-K. Our audit committee will assist the board of directors in its oversight of the integrity of our financial statements and our compliance with legal and regulatory requirements and corporate policies and controls. Our audit committee will have 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. Our audit committee will also be responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm will be given unrestricted access to our audit committee.

Conflicts Committee

At least two members of the board of directors of our general partner will serve on our conflicts committee to review specific matters that may involve conflicts of interest in accordance with the terms of our partnership agreement. John T. McNabb II and Stan A. Lybarger serve as the members of the conflicts committee. Mr. McNabb serves as the Chairman of the conflicts committee. The board of directors of our general partner will determine whether to refer a matter to the conflicts committee on a case-by-case basis. The members of our conflicts committee may not be officers or employees of our general partner or directors, officers, or employees of its affiliates, and must meet the independence and experience standards established by the NYSE and the Exchange Act to serve on a committee of a board of directors. In addition, the members of our conflicts committee may not own any interest in our general partner or any interest in us or our subsidiaries other than common units or awards under our incentive compensation plan. If our general partner seeks approval from the conflicts committee, then it will be presumed that, in making its decision, the conflicts committee acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the partnership challenging such determination, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption. Please read "*Conflicts of Interest and Duties*."

Directors and Executive Officers of Cypress Energy Partners GP, LLC

Directors are elected by Holdings and hold office until their successors have been elected or qualified or until their earlier death, resignation, removal or disqualification. Executive officers are appointed by, and serve at the discretion of, the board of directors. The following table shows information for the directors and executive officers of our general partner.

Name	**Age**	**Position with Cypress Energy Partners GP, LLC**
Peter C. Boylan III	53	Chairman of the Board, Chief Executive Officer and President
G. Les Austin	51	Senior Vice President and Chief Financial Officer
Richard M. Carson	50	Senior Vice President and General Counsel
Henry Cornell	60	Director
Stanley A. Lybarger	67	Director & Audit Committee Chairman
John T. McNabb, II	72	Director & Conflicts Committee Chairman
Charles C. Stephenson, Jr.	80	Director

Peter C. Boylan III became co-Founder, President and Chief Executive Officer of Holdings in April 2012, and Chairman of the Board, President and Chief Executive Officer of Cypress Energy Partners GP, LLC, in September 2013. Since March 2002, Mr. Boylan has been the Chief Executive Officer of Boylan Partners, LLC, a provider of investment and advisory services. From 1995 to 2004, Mr. Boylan served in a variety of senior executive management positions of various public and private companies controlled by Liberty Media Corporation, including serving as a board member, Chairman, President, Chief Executive Officer, Chief Operation Officer and Chief Financial Officer of several different companies. Mr. Boylan currently serves on the board of directors of publicly traded BOK Financial Corporation. Mr. Boylan has also served on over a dozen other public and private company boards of directors over the last 20+ years. Mr. Boylan has extensive corporate senior executive management and leadership experience, and specific expertise with accounting, finance, audit, risk and compensation committee service, intellectual property, corporate development, health care, media, cable and satellite TV, software development, technology, energy and civic and community service. We believe this experience suits Mr. Boylan to serve as Chairman of the Board, Chief Executive Officer and President.

G. Les Austin is Senior Vice President and Chief Financial Officer of Cypress Energy Partners GP, LLC, having served in that capacity since March 2016 and having previously served as Vice President and Chief Financial Officer since September 2013. Mr. Austin has served as Vice President and Chief Financial Officer of CEP LLC since October 1, 2012. Mr. Austin served as Senior Vice President, Chief Financial Officer, secretary and treasurer of RAM Energy Resources, Inc. from April 2008 until its sale in February 2012. Mr. Austin served as Vice President Finance and Chief Financial Officer of Matrix Service Company from June 2004 to March 2008. Mr. Austin also served Matrix as Vice President, Accounting and Administration, Vice President of Financial Reporting and Technology, and as Vice President of Financial Planning and Reporting. Mr. Austin served as Vice President of Finance for Flint Energy Construction Company from February 1994 to March 1999. Prior to February 1994, Mr. Austin was an audit manager with Ernst & Young LLP. Mr. Austin received a B.S. in Accounting and Information Technology from Oklahoma State University. He is a Certified Public Accountant and a member of the American Institute of Certified Public Accountants. In addition, Mr. Austin serves as a director on the Advisory Board of Oklahoma State University School of Accounting.

Richard M. Carson is Senior Vice President and General Counsel of Cypress Energy Partners GP, LLC, having served in that capacity since March 2016 and having previously served as Vice President and General Counsel since September 2013. Mr. Carson served as a director, officer, and shareholder of Gable & Gotwals, a Professional Corporation (“GableGotwals”), a premier Oklahoma law firm, where he practiced securities, corporate finance, transactional and environmental law, primarily for clients in the energy industry, including several master limited partnerships. Prior to joining GableGotwals, from 1999 to 2008, Mr. Carson served in the legal department of The Williams Companies, Inc. (“Williams”), where he counseled Williams in regard to securities, corporate finance, and environmental matters, particularly relating to Williams’ master limited partnership subsidiaries, Williams Partners L.P., Williams Pipeline Partners L.P., and Williams Energy Partners L.P. (predecessor to Magellan Midstream Partners, L.P.). Mr. Carson began his career in 1991 working in legal, compliance, and management roles, primarily in the environmental services industry, before joining Williams. Mr. Carson received a Juris Doctor in 1991 from the University of Oklahoma and a Bachelor of Science, Cum Laude, from the University of Tulsa’s Honors Program in 1988. Mr. Carson serves as Chairman of the board of directors of Land Legacy. He has previously served as the Chair of the Oklahoma Bar Association’s Environmental Law Section, and the chair of the Environmental Auditing Roundtable’s South-Central Region.

Henry Cornell became a director of our board effective at the close of our public offering. Mr. Cornell is the Founder and Senior Partner of Cornell Capital LLC, a New York-based private investment firm formed in 2013. Mr. Cornell was formerly a vice-chairman of the merchant banking division of Goldman Sachs & Co., where he worked for nearly 30 years prior to his retirement in February 2013. Mr. Cornell served on the firm's corporate, real estate and infrastructure investment committees. He also led Goldman Sachs & Co.'s investment activities in Asia from 1988 – 2000. Prior to joining Goldman Sachs & Co., Mr. Cornell worked at Davis Polk & Wardwell. Mr. Cornell is also a member of the Board of Trustees of Mt. Sinai, the Whitney Museum, The Asia Society and the Navy SEAL Foundation, and a member of the Council on Foreign Relations. Mr. Cornell received his B.A. from Grinnell College in 1976 and his J.D. from New York Law School in 1981.

Stanley A. Lybarger has served as a director on the board of Cypress Energy Partners GP, LLC since March 5, 2014. Mr. Lybarger retired as president and chief executive officer of BOK Financial, a top 25 US-based bank, on January 1, 2014. He continues to serve on the board of directors of that corporation. Mr. Lybarger had a 40-year career with BOK Financial. Mr. Lybarger served as its first president and chief operating officer, in addition to continuing to hold that title for Bank of Oklahoma. He became the chief executive officer for BOK Financial and Bank of Oklahoma in 1996. Mr. Lybarger earned B.A. and M.B.A. degrees from the University of Kansas, and a Certification from the Stonier Graduate School of Banking at Rutgers University. Mr. Lybarger has also been an industry and community leader for decades and has held leadership positions at a number of organizations, including serving on the Federal Advisory Council (a 12-member council which consults and advises the Federal Reserve Board of Governors in Washington, DC), the Executive Committee of the Financial Institutions Division of the American Bankers Association, Chairman of the Tulsa Stadium Trust, Chairman of the Tulsa Metro Chamber, Chairman of the Oklahoma State Chamber, Chairman of the Oklahoma Business Roundtable and Chairman of Tulsa Area United Way. Mr. Lybarger currently serves on the board of directors of BOK Financial.

John T. McNabb II has served on the board of directors of Cypress Energy Partners GP, LLC, the general partner of the Partnership, where he has served as the Chairman of the Conflicts Committee. He co-founded the Trump Leadership Council in April 2016 and has served on the council since its founding. Mr. McNabb has served on the boards of eight publicly traded companies and currently sits on the board of Continental Resources (where he has served as Lead Director). Mr. McNabb was elected to serve as non-executive Chairman of the Board of Willbros Group, Inc. from September 2007 until August 2014 when he was appointed Executive Chairman. He was appointed Chief Executive Officer in October 2014 and elected to the board of Directors in August 2006. Effective December 1, 2015, Mr. McNabb retired from his positions as Chairman and Chief Executive Officer and did not stand for re-election when his term as Director expired in 2016. Mr. McNabb also serves as Senior Advisor and was formerly Vice Chairman, Corporate Finance of Duff & Phelps Securities LLC, a leading global financial advisory firm. Prior thereto, Mr. McNabb was a founder and Chairman of Growth Capital Partners LP and formerly was a Managing Director of Bankers Trust New York Corporation and a board member of BT Southwest Inc., a wholly owned subsidiary of Bankers Trust. Prior thereto, he served in various capacities with The Prudential Insurance Company of America including having responsibility for a multi-billion dollar investment portfolio primarily focused on energy investments. He started his energy career with Mobil Oil in the E&P Division. He has owned equity interests in approximately twenty private energy related companies and acted in operating or financial roles in several. Mr. McNabb has also served as a director of twelve private energy companies located in both Canada and the United States. He is an emeritus member of the board of Visitors of The Fuqua School of Business at Duke University and served as Chairman of the Board of Visitors of The University of Houston and also served as Chairman of the Dean's Advisory Board at The Bauer College of Business and as an Executive Professor of Finance at the University of

Houston. Mr. McNabb holds BA and MBA degrees from Duke University and served in the US Air Force during the Vietnam conflict, rising to the rank of Captain and was awarded the Air Medal with three Oak Leaf Clusters and the Distinguished Flying Cross.

Charles C. Stephenson, Jr. has been a director on the board of Cypress Energy Partners GP, LLC since the close of the initial public offering in January 2014. Previously, Mr. Stephenson served as Chairman of the board of Premier Natural Resources, an independent oil and gas company of which he is also a co-founder. Mr. Stephenson is also an owner of Regent Private Capital II LLC and was a co-founder and director of Growth Capital Partners, an investment and merchant banking firm. From 1983 to 2006, Mr. Stephenson worked for Vintage Petroleum, Inc. which he founded and for which he served as Chairman of the Board, President, and Chief Executive Officer at the time of its sale to Occidental Petroleum in 2006. Mr. Stephenson received a B.S. in petroleum engineering from the University of Oklahoma. Mr. Stephenson is a member of the Society of Petroleum Engineers and has served on the board of the National Petroleum Council.

Board Leadership Structure

The chief executive officer of our general partner currently serves as the chairman of the board. The board of directors of our general partner has no policy with respect to the separation of the offices of chairman of the board of directors and chief executive officer. Instead, that relationship is defined and governed by the amended and restated limited liability company agreement of our general partner, which permits the same person to hold both offices. Directors of the board of directors of our general partner are designated or elected by a wholly owned subsidiary of Holdings. Accordingly, unlike holders of common stock in a corporation, our unitholders will have only limited voting rights on matters affecting our business or governance, subject in all cases to any specific unitholder rights contained in our partnership agreement.

Board Role in Risk Oversight

Our organizational governance guidelines will provide that the board of directors of our general partner are responsible for reviewing the process for assessing the major risks facing us and the options for their mitigation. This responsibility will be largely satisfied by our audit committee, which is responsible for reviewing and discussing with management and our registered public accounting firm our major risk exposures and the policies management has implemented to monitor such exposures, including our financial risk exposures and risk management policies

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires our general partner's board of directors and officers, and persons who beneficially own more than 10% of a class of our equity securities registered pursuant to Section 12 of the Exchange Act to file certain reports with the SEC and NYSE concerning beneficial ownership of such securities. To our knowledge, based solely on a review of the copies of such reports furnished to us and written representations by our directors and officers, we believe that all reporting obligations of our general partner's directors and officers and our greater than 10% unitholders under Section 16(a) were satisfied during the year ended December 31, 2016.

Corporate Governance

The board of directors of our general partner has adopted Corporate Governance Guidelines that outline important policies and practices regarding our governance and a Code of Business Conduct and Ethics that applies to the directors, officers and employees of our general partner and its affiliates and us.

Non-management directors of our general partner meet in executive session without management participation at each meeting of the board of directors. These executive sessions are chaired by Stanley A. Lybarger, the current chairman of our audit committee, or such independent director as he designates. Interested parties may communicate directly with the independent directors by submitting a communication in an envelope marked “Confidential” addressed to the “Independent Members of the Board of Directors” in care of Mr. Lybarger at:

Cypress Energy Partners GP, LLC

5727 S. Lewis Avenue, Suite 300

Tulsa, Oklahoma 74105

We make available free of charge, within the “*Corporate Governance*” section of our website at www.cypressenergy.com, the Corporate Governance Guidelines, the Code of Business Conduct and Ethics and our Audit Committee Charter. The information contained on, or connected to, our website is not incorporated by reference into this Annual Report on Form 10-K and should not be considered part of this or any other report that we file with or furnish to the SEC.

ITEM 11. EXECUTIVE COMPENSATION

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

Compensation Overview

Executive Compensation

We do not directly employ any of the persons responsible for managing our business. Our general partner, under the direction of its board of directors, or the board, is responsible for managing our operations and CEM LLC employs the employees that operate our business. The compensation payable to the officers of our general partner is paid by CEM LLC and such payments are reimbursed by us. However, we sometimes refer to the employees and officers of our general partner as our employees and officers in this report.

This executive compensation disclosure provides an overview of the executive compensation program for our named executive officers identified below. For the year ended December 31, 2016, our named executive officers ("NEOs") were:

- Peter C. Boylan III, our Chairman, Chief Executive Officer and President;
- G. Les Austin, our Senior Vice President and Chief Financial Officer; and
- Richard M. Carson, our Senior Vice President and General Counsel.

Summary Compensation Table For 2016

The following table sets forth certain information with respect to the compensation paid to our NEOs for the years ended December 31, 2016, 2015 and 2014.

Name and Principal Position	Year	Salary	Bonus (a)	Unit Awards (b)	All Other Compensation (c)	Total
Peter C. Boylan III	2016	$411,712	$65,000	$554,167	$ —	$1,030,879
Chairman, Chief Executive Officer and	2015	399,050	38,609	593,173	—	1,030,832
President	2014	352,512	—	—	2,390	354,902
G. Les Austin	2016	$275,000	$25,000	$185,076	$ —	$485,076
Senior Vice President and Chief Financial	2015	260,000	20,000	203,907	—	483,907
Officer	2014	211,667	70,000	599,712	—	881,379
Richard M. Carson	2016	$275,000	$25,000	$185,076	$ —	$485,076
Senior Vice President and General Counsel	2015	259,375	20,000	203,907	—	483,282
	2014	211,458	30,000	272,488	—	513,946

(a) Represents cash bonus awards paid. For more information, see “Bonus awards” below.

(b) Represents the grant date fair value of awards granted under the Cypress Energy Partners, L.P. 2013 Long-Term Incentive Plan as determined in accordance with FASB ASC Topic 718, as well as the change in grant date fair value associated with the conversion of previously granted CEP LLC awards into subordinated units (converted to common units as of February 14, 2017) in us for Mr. Austin and Mr. Carson, which amounts consist of $344,081 for Mr. Austin and $158,213 for Mr. Carson in 2014. For additional information, please see Note 11 to the Consolidated Financial Statements included in Item 8 of this Annual Report.

(c) Represents cash payments provided for healthcare premiums for Mr. Boylan in 2014. These payments were made in lieu of our providing any health or welfare benefits to Mr. Boylan.

Narrative Disclosure to Summary Compensation Table

Elements of the compensation program. For 2016, the primary elements of compensation for our NEOs included base salary, cash bonus awards and equity awards.

Base compensation for 2016. Base salaries for our NEOs were originally set at modest levels, primarily due to our limited operating history at the time such salaries were determined. Salaries were increased in February 2014 following the IPO to bring them more in line with competitive salaries in our industry.

The following table sets forth the current annualized base salary rates for our NEOs as of December 31, 2016.

Name and Principal Position	**Current Base Salary**
Peter C. Boylan III Chairman, Chief Executive Officer and President	$ 411,712
G. Les Austin Senior Vice President and Chief Financial Officer	$ 275,000
Richard M. Carson Senior Vice President and General Counsel	$ 275,000

Bonus awards. Our NEOs are eligible to receive discretionary cash bonus awards as our general partner's board of directors may determine from time to time. For 2016 and 2015, Mr. Boylan, Mr. Austin and Mr. Carson received cash bonus awards. For 2014, Mr. Austin and Mr. Carson received cash bonus awards. Mr. Boylan's, Mr. Austin's and Mr. Carson's bonus awards were granted based on subjective performance determinations.

Discretionary long-term equity incentive awards. In December 2012, in connection with his commencement of employment, Mr. Austin, received a one-time award of Class C Units in CEP LLC, which were intended to allow Mr. Austin to share in the future equity appreciation of CEP LLC from and after the date of grant of such Class C Units. Mr. Carson received a similar award in connection with his commencement of service in September 2013. The awards vest in three equal annual installments on the third, fourth and fifth anniversary of the grantee's commencement of service with us, respectively. In connection with our IPO, the Class C units in CEP LLC were converted into subordinated units in us on an equivalent value basis, based on the per unit price in our IPO and with the same vesting terms as applied to the Class C Units. Mr. Austin's award converted into 30,143 subordinated units and Mr. Carson's award converted into 14,308 subordinated units. These subordinated units have been converted to common units as the Partnership emerged from subordination as of February 14, 2017.

In connection with our IPO, we adopted the Cypress Energy Partners, L.P. 2013 Long-Term Incentive Plan, or the LTIP, under which we make periodic grants of equity and equity-based awards in us to our NEOs and other key employees and other service providers. In addition to the equity awards received by Mr. Austin and Mr. Carson in connection with the conversion of previously issued awards in CEP LLC described above, in 2016, 2015 and 2014, we granted long-term incentive awards to Mr. Austin and Mr. Carson in the form of phantom units. The phantom units are scheduled to vest in three equal annual installments on each of the third, fourth and fifth anniversaries of the grant date, subject to the NEO's continued employment with us on the applicable vesting date and potential accelerated vesting as described below under "*Severance and change in control arrangements*."

Outstanding Equity Awards at December 31, 2016

The following table provides information regarding the outstanding and unvested long-term equity incentive awards held by our NEOs as of December 31, 2016. None of our NEOs held any option awards that were outstanding as of December 31, 2016.

Name and Principal Position	**Grant Date**	**Number of Units That Have Not Vested** #		**Market Value of Units That Have Not Vested** (a)
Peter C. Boylan III (b)	March 10, 2016	88,636	(c)	935,110
Chairman, Chief Executive Officer and President	March 26, 2015	47,365	(c)	499,701
G. Les Austin	March 10, 2016	29,602	(c)	312,301
Senior Vice President and Chief Financial Officer	March 26, 2015	16,282	(c)	171,775
	February 1, 2014	6,856	(c)	72,331
	—	10,048	(d)	106,006
Richard M. Carson	March 10, 2016	29,602	(c)	312,301
Senior Vice President and General Counsel	March 26, 2015	16,282	(c)	171,775
	February 1, 2014	1,714	(c)	18,083
	—	9,539	(d)	100,636

(a) Amount shown reflects the per-unit value based upon the December 31, 2016 closing price of $10.55 per common unit.

(b) In addition to equity awards, as our co-founder Mr. Boylan also owns a part of Holdings.

(c) Represents phantom units granted under the LTIP and scheduled to vest in three equal annual installments on the third, fourth and fifth anniversaries of the grant date.

(d) Represents subordinated units in us into which previously issued awards in CEP LLC that were outstanding as of December 31, 2013 were converted upon the closing of our IPO on January 21, 2014 based upon the IPO price of $20.00 per common unit. The remaining subordinated units for Mr. Austin are scheduled to vest into common units on October 1, 2017. The subordinated units for Mr. Carson are scheduled to vest into common units in two annual installments on each of September 30, 2017 and 2018.

Severance and change in control arrangements. None of our NEOs has entered into any employment or severance agreements with our general partner or any of its affiliates.

The terms of Mr. Austin’s and Mr. Carson’s subordinated unit awards provide that in the event of a change in control of the Partnership, their subordinated unit awards would become fully vested into common units, effective immediately prior to such change in control; and the terms of their phantom restricted unit awards provide that in the event of a change in control of the partnership, their phantom restricted units would become fully vested should they no longer remain employed in their respective positions within six months after such change in control.

Retirement, Health, Welfare and Additional Benefits

We provide a basic benefits package that is available to all full-time employees, which currently includes medical, dental, disability and life insurance and a 401(k) plan. We do not expect to maintain a defined benefit pension plan for our executive officers, because we believe such plans primarily reward longevity rather than performance.

Director Compensation

Officers, employees or paid consultants or advisors of us or our general partner or its affiliates who also serve as directors do not receive additional compensation for their service as directors. Our independent directors who are not officers, employees or paid consultants or advisors of us or our general partner or its affiliates receive cash and equity-based compensation for their services as directors.

Our non-employee director compensation program consists of the following:

an annual cash retainer of $25,000,

an additional annual cash retainer of (i) $5,000 for service as the chair of our conflicts committee and (ii) $7,500 for service as the chair of our audit committee, and

an annual equity-based award granted under our LTIP, having a value as of the grant date of $50,000. Equity-based awards are subject to vesting in equal annual installments over a period of three years, based upon continued service as an independent director.

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

In addition to the compensation described above, Mr. McNabb and Mr. Lybarger were awarded one phantom unit under the LTIP for each common unit they purchased in the directed unit program or in the open market from the time of our IPO through May 31, 2014 for a total of 15,000 phantom units for Mr. McNabb and 4,000 phantom units for Mr. Lybarger. The phantom units will vest in three equal annual installments.

The following table provides information regarding the compensation earned by our non-employee directors during the years ended December 31, 2016, 2015 and 2014.

Name	Year	Cash Fees Earned	Unit Awards (a)	Total
Henry Cornell	2016	$25,000	$39,861	$64,861
	2015	25,000	41,384	66,384
	2014	25,000	21,540	46,540
Stanley A. Lybarger	2016	$32,500	$39,861	$72,361
	2015	32,500	41,384	73,884
	2014	32,500	100,505	133,005
John T. McNabb II	2016	$30,000	$39,861	$69,861
	2015	30,000	41,384	71,384
	2014	30,000	297,728	327,728

(a) Represents the grant date fair value of the awards, as determined in accordance with FASB ASC Topic 718. For additional information, please see Note 11 to the Consolidated Financial Statements included in Item 8 in this Annual Report.

Compensation Committee Interlocks and Insider Participation

As a limited partnership, we are not required by the NYSE to establish a compensation committee. Mr. Boylan III, who serves as the Chairman of the Board participates in his capacity as a director in the deliberations of the Board concerning executive officer compensation. In addition, Mr. Boylan III makes recommendations to the Board regarding named executive officer compensation but abstains from any decision regarding his own compensation.

Compensation Committee Report

Neither we nor our general partner has a compensation committee. The board of directors of our general partner has reviewed and discussed the Compensation Overview set forth above and based on this review and discussion has approved it for inclusion in this Annual Report on Form 10-K.

Members of the Board of Directors of Cypress Energy Partners GP, LLC

Peter C. Boylan III Henry Cornell
Stanley A. Lybarger John T. McNabb II Charles C. Stephenson, Jr.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The following table sets forth the beneficial ownership of units of Cypress Energy Partners, L.P., as of March 8, 2017, held by beneficial owners of 5.0% or more of the units, by each director and named executive officer of Cypress Energy Partners GP, LLC, our general partner, and by all directors and executive officers of our general partner as a group. The percentage of units beneficially owned is based on a total of 11,869,195 common units outstanding.

The amounts and percentage of units beneficially owned are reported on the basis of regulations of the SEC governing the determination of beneficial ownership of securities. Under the rules of the SEC, a person is deemed to be a "beneficial owner" of a security if that person has or shares "voting power," which includes the power to vote or to direct the voting of such security, or "investment power," which includes the power to dispose of or to direct the disposition of such security. In computing the number of common units beneficially owned by a person and the percentage ownership of that person, common units subject to options or warrants held by that person that are currently exercisable or exercisable within 60 days of March 10, 2017, if any, are deemed outstanding, but are not deemed outstanding for computing the percentage ownership of any other person. Except as indicated by footnote, the persons named in the table below have sole voting and investment power with respect to all units shown as beneficially owned by them, subject to community property laws where applicable. Unless otherwise indicated, the address for each of the beneficial owners below is 5727 S. Lewis Avenue, Suite 300, Tulsa, Oklahoma 74105.

Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned	
Cypress Energy Holdings, LLC (a) (b)	6,957,349	58.6	%
Peter C. Boylan III	20,242	*	
G. Les Austin	46,824	*	
Richard M. Carson	22,837	*	
Henry Cornell	1,742	*	
John T. McNabb II	33,242	*	
Stanley A. Lybarger	22,329	*	
Charles C. Stephenson, Jr.	413,740	3.5	%
All directors and executive officers as a group (consisting of 7 persons)	560,956	4.7	%

* indicates that person or entity owns less than one percent.

(a) Cypress Energy Holdings, LLC owns 100% of Cypress Energy Investments, LLC, which owns 100% of CEP TIR. CEP TIR owns 11.3% of our common units.

(b) Cypress Energy Holdings, LLC owns 100% of Cypress Energy Holdings II, LLC, which owns 100% of our general partner. Cypress Energy Holdings II, LLC owns 47.3% of our common units. The following table sets forth the beneficial ownership of Cypress Energy Holdings, LLC.

Name of Beneficial Owner		Ownership Interest Ratio (1)	
Cynthia A. Field Trust	(2)	36.750	%
Charles C. Stephenson, Jr.		27.468	%
CEP Capital Partners, LLC	(3)	24.500	%
Henry Cornell		1.333	%
Cornell Investment Partners, L.P.		0.667	%
Lawrence D. Field, Jr. Trust	(2)	1.547	%
Alex S. Field Trust	(2)	1.547	%
Andrew M. Field Trust	(2)	1.547	%
Corry C. Stephenson Trust	(2)	1.547	%
Kelly C. Stephenson Trust	(2)	1.547	%
Julie A. Stephenson Trust	(2)	1.547	%

(1) Cypress Energy Holdings, LLC is managed by a three-member board of directors consisting of Peter C. Boylan III, Lawrence D. Field and Charles C. Stephenson, Jr. The election of each director requires the affirmative vote of members representing at least a majority of the voting ratio of Holdings and the concurrence of CEP Capital Partners, LLC.

(2) Voting rights of the trust are exercised by Cynthia A. Field, as trustee.

(3) CEP Capital Partners, LLC is owned and controlled by affiliates of Peter C. Boylan III, our Chairman, Chief Executive Officer and President.

Securities Authorized for Issuance under Equity Compensation Plans

In connection with the consummation of our IPO on January 21, 2014, the board of directors of our general partner adopted the 2013 Long-Term Incentive Plan. The following table provides certain information with respect to this plan as of December 31, 2016:

Plan Category	Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights	Weighted Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance under Equity Compensation Plans
Equity compensation plans approved by security holders	606,250	—	576,350
Equity compensation plans not approved by security holders	—	—	—
Total	606,250	—	576,350

Amounts shown represent outstanding phantom units. The phantom units do not have an exercise price.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Parent of Smaller Reporting Entities

We have no parents, though Holdings may be considered to be our parent by virtue of its indirect ownership of 58.6% of our outstanding common units, and the owners of Holdings own 100.0% of Cypress Energy GP Holdings, LLC, which owns 100.0% of our general partner. Holdings II and Cypress Energy Investments, LLC are both wholly owned subsidiaries of Holdings. Holdings II directly holds 5,610,549 of our outstanding common units. Cypress Energy Investment, LLC owns 100.0% of Cypress Energy Partners – TIR, LLC, which directly holds 1,346,800 of our outstanding common units.

Conflicts of Interest and Duties

Under our partnership agreement, our general partner has a contractual duty to manage us in a manner it believes is in the best interests of our partnership and unitholders. However, because our general partner is a wholly owned subsidiary of Holdings, the officers and directors of our general partner have a duty to manage the business of our general partner in a manner that is in the best interests of Holdings. As a result of this relationship, conflicts of interest may arise in the future between us and our unitholders, on the one hand, and our general partner and its affiliates, including Holdings, on the other hand. For example, our general partner will be entitled to make determinations that affect the amount of cash distributions we make to the holders of common units, which in turn has an effect on whether our general partner receives incentive cash distributions. In addition, our general partner may determine to manage our business in a way that directly benefits Holdings' businesses, rather than indirectly benefitting Holdings solely through its ownership interests in us. We expect that any future decision by Holdings in this regard will be made on a case-by-case basis. However, all of these actions are permitted under our partnership agreement and will not be a breach of any duty (fiduciary or otherwise) of our general partner.

Delaware law provides that Delaware limited partnerships may, in their partnership agreements, expand, restrict or eliminate the duties (including fiduciary duties) otherwise owed by the general partner to limited partners and the partnership. As permitted by Delaware law, our partnership agreement contains various provisions replacing the fiduciary duties that would otherwise be owed by our general partner with contractual standards governing the duties of the general partner and contractual methods of resolving conflicts of interest. The effect of these provisions is to restrict the remedies available to unitholders for actions that might otherwise constitute breaches of our general partner's fiduciary duties. Our partnership agreement also provides that affiliates of our general partner, including Holdings and its controlled affiliates, are permitted to compete with us, and neither our general partner nor its affiliates have any obligation to present business opportunities to us. By purchasing a common unit, the purchaser agrees to be bound by the terms of our partnership agreement, and pursuant to the terms of our partnership agreement, each holder of common units consents to various actions and potential conflicts of interest contemplated in our partnership agreement that might otherwise be considered a breach of fiduciary or other duties under Delaware law.

As of December 31, 2016, the general partner and its controlled affiliates own 1,344,650 common units and 5,612,699 subordinated units, representing a 58.6% limited partner interest in us. In addition, our general partner owns a 0.0% non-economic general partner interest in us.

Distributions and Payments to Our General Partner and Its Affiliates

The following table summarizes the distributions and payments to be made by us to our general partner and its controlled affiliates in connection with the formation, ongoing operation, and liquidation of Cypress Energy Partners, L.P. These distributions and payments were determined by and among affiliated entities and, consequently, are not the result of arm's-length negotiations.

<u>Formation Stage</u>

The consideration received by our general partner and its controlled affiliates prior to or in connection with the IPO for the contribution of the assets and liabilities to us	1,344,650 common units; 5,612,699 subordinated units; 0.0% non-economic general partner interest;

the incentive distribution rights; and

a cash payment of approximately $80.2 million from the proceeds of the IPO.

Operational Stage

Distributions of available cash to our general partner and its controlled affiliates	We will generally make cash distributions to the unitholders pro rata, including Holdings and its controlled affiliates, as holder of an aggregate of 6,957,349 common units. In addition, if distributions exceed the minimum quarterly distribution and target distribution levels, the incentive distribution rights held by affiliates of our general partner will entitle the IDR owners to increasing percentages of the distributions in steps, up to 50% of the distributions above the highest target distribution level.
	During the year ended December 31, 2016, the year ended December 31, 2015, and the period of January 21, 2014 through December 31, 2014 (the pro-rata period from the closing of our IPO through year end) the distribution on all of our outstanding units for four quarters, our general partner and its affiliates received approximately $12.3 million, $12.3 million, and $11.3 million, respectively.

127

Payments to our general partner and its affiliates	Under our partnership agreement, we are required to reimburse our general partner and its affiliates for all costs and expenses that they incur on our behalf for managing and controlling our business and operations. Except to the extent specified under our amended and restated omnibus agreement, our general partner determines the amount of these expenses and such determinations must be made in good faith under the terms of our partnership agreement. Under our amended and restated omnibus agreement, we reimbursed our general partner $4.0 million and $3.8 million in annual administrative fees for expenses incurred by it and their respective affiliates in providing certain partnership overhead services to us, including the provision of executive management services by certain officers of our general partner for the year ended December 31, 2015 and the period of January 21, 2014 through December 31, 2014 (the pro-rata period from the closing of our IPO through year end), respectively. This fee also included $2.0 million in annual cash expense we incurred as a result of being a publicly traded partnership. The annual administrative fee is subject to increase by an annual amount equal to PPI plus one percent or, with the concurrence of the conflicts committee, in the event of an expansion of our operations, including through acquisitions or internal growth. During the year ended December 31, 2016, we did not reimburse our general partner for these administrative fees, because the general partner waived the fees for that year. Please read "*Agreements with Affiliates — Omnibus Agreement*" below and "*Compensation Overview*."
Withdrawal or removal of our general partner	If our general partner withdraws or is removed, its general partner interest and its incentive distribution rights will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.

Liquidation Stage

Liquidation	Upon our liquidation, the partners, including our general partner, will be entitled to receive liquidating distributions according to their respective capital account balances.

Agreements with Affiliates

On January 21, 2014, we and other parties entered into the various agreements associated with the closing of our IPO, including the vesting of assets in, and the assumption of liabilities by, us and our subsidiaries.

Omnibus Agreement

We are party to an amended and restated omnibus agreement with Holdings, CEM LLC, CEP LLC, our general partner, CEP TIR, the TIR Entities, Charles C. Stephenson, Jr. and Cynthia A. Field that address the following matters, among other things:

- our payment of an annual administrative fee to be paid in quarterly installments to Holdings for providing us with certain partnership overhead services, including for certain executive management services by certain officers of our general partner, and compensation expense for all employees required to manage and operate our business. This fee also includes the incremental general and administrative expenses we incur as a result of being a publicly traded partnership;

- our right of first offer on Holdings' and its subsidiaries' assets used in, and entities primarily engaged in, providing saltwater disposal and other water and environmental services; and

- indemnification of us by Holdings for certain environmental and other liabilities, including events and conditions associated with our operation of assets that occur prior to the closing of the IPO and our obligation to indemnify Holdings for events and conditions associated with the operation of our assets that occur after the closing of the IPO and for environmental liabilities related to our assets to the extent Holdings is not required to indemnify us.

So long as Holdings controls our general partner, our amended and restated omnibus agreement will remain in full force and effect, unless we and Holdings agree to terminate it sooner. If Holdings ceases to control our general partner, either party may terminate our amended and restated omnibus agreement, provided that the indemnification obligations will remain in full force and effect in accordance with their terms. We and Holdings may agree to amend our amended and restated omnibus agreement; however, amendments that the general partner determines are adverse to our unitholders will also require the approval of the conflicts committee.

Payment of Administrative Fee and Reimbursement of Expenses

We pay an annual administrative fee in quarterly installments to Holdings. The administrative fee is intended to reimburse Holdings for providing us with certain partnership overhead services, including for certain executive management services by certain officers of our general partner, and for paying on our behalf all compensation expense for the employees required to manage and operate our business and all expenses incurred by us as a result of our becoming and continuing as a publicly traded entity, including costs associated with Exchange Act filings, independent public accounting firm fees, partnership governance and compliance, registrar and transfer agent fees, tax return and Schedule K-1 preparation and distribution, legal fees and director compensation.

The amount of the administrative fee is subject to increase each year by the percentage equal to the increase, if any, in the PPI plus 1.0%. In addition, the administrative fee may be increased with the approval of our conflicts committee in the event of an expansion of our operations, including though acquisitions or internal growth, a change in applicable law or regulation, or as agreed upon by us and our general partner.

We did not pay this administrative fee to Holdings during the year ended December 31, 2016, because Holdings waived the fee for that year.

Right of First Offer

Under our amended and restated omnibus agreement, if Holdings or its controlled subsidiaries decide to sell, transfer or otherwise dispose of any of the assets or entities listed below within a five-year period following the closing of the IPO, Holdings will provide notice to us of such intended disposition and provide us with the opportunity to make the first offer on any assets used in, or entities engaged primarily in, providing saltwater disposal and other water and environmental services to U.S. onshore oil and natural gas producers and trucking companies in the U.S., including any assets or entities currently owned by or acquired from SBG Energy Services, LLC.

After receiving the notice of Holdings' intention to sell or transfer such assets, we will have 45 days to make an offer to Holdings with our proposed terms for the acquisition. The consummation and timing of any acquisition by us of the assets covered by our right of first offer will depend upon, among other things, our ability to reach an agreement with Holdings on price and other terms and our ability to obtain financing on acceptable terms. Accordingly, we can provide no assurance whether, when or on what terms we will be able to successfully consummate any future acquisitions pursuant to our right of first offer, and Holdings is under no obligation to accept any offer that we may choose to make or to enter into any commercial agreements with us.

Indemnification

Under our amended and restated omnibus agreement, Holdings will indemnify us, without giving effect to any cap, for the following matters:

Environmental: all known and unknown environmental liabilities that are associated with the ownership or operation of our assets and due to occurrences on or before the closing of the IPO. Indemnification for any unknown environmental liabilities will be limited to liabilities arising out of occurrences in existence before the closing of the IPO and identified prior to the third anniversary of the closing of the IPO, and will be subject to an aggregate deductible of $350,000 before we are entitled to indemnification;

Retained Assets: all events and conditions associated with any assets retained by Holdings regardless of when they occur;

IPO Transactions: for a period of five years after the closing of the IPO to the extent not covered by other indemnifications in our amended and restated omnibus agreement, the formation transactions, asset contributions and ownership of the contributed assets prior to the closing, as well as any event or condition that arise out of ownership of the contributed assets prior to closing;

Titles and Permits: for a period of five years after the closing of the IPO, any failure to have at the closing of the offering any title, right of way, consent, license, permit, or approval necessary for us to own or operate our assets in substantially the same manner that the assets were owned or operated immediately prior to the closing of the IPO and as described in this report, subject to an aggregate deductible of $500,000;

Litigation: any legal proceedings attributable to ownership or operation of the contributed assets prior to the closing of the IPO, except that indemnification for any legal proceeding not known at the time of the closing of the IPO is subject to an aggregate deductible of $250,000;

TIR Restructuring Transactions: the acquisition of the shares in Tulsa Inspection Resources, Inc. and the merger of Tulsa Inspection Resources, Inc. with the TIR Entities; and

Tax Liabilities: for a period up to 60 days past the expiration of any applicable statute of limitations, any tax liability attributable to the assets contributed to us arising prior to the closing of the IPO or otherwise related to Holdings' contribution of those assets to us in connection with the IPO.

We have agreed to indemnify Holdings, without giving effect to any deductible or cap, for events and conditions associated with the operation of our assets that occur after the closing of the IPO and for environmental liabilities related to our assets to the extent Holdings is not required to indemnify us as described above.

Contribution Agreement

In connection with the closing of the IPO, we entered into a contribution agreement with Holdings and certain of its subsidiaries that effected the restructuring transactions, including the transfer of CEP LLC to us and the use of the net proceeds of the IPO.

Contribution, Conveyance and Assumption Agreement

On February 20, 2015, we entered into a contribution agreement with CEP LLC, our General Partner, Holdings, CEP-TIR, Mr. Charles C. Stephenson, Jr. and Ms. Cynthia A. Field (together with CEP-TIR and Mr. Charles C Stephenson, Jr., the "Contributors"). The following transactions contemplated by the Contribution Agreement occurred at the simultaneous closing:

a series of conveyances, contributions and distributions by each of the Contributors to the Partnership, and ultimately to CEP LLC, of the remaining 49.9% limited liability company interest not previously owned by the Partnership in each of the TIR Entities;

payment to the Contributors of an aggregate $52.6 million in cash borrowed under our secured Credit Agreement with Deutsche Bank AG, New York Branch and BMO Harris Bank; and

amending and restating of the omnibus agreement, as described above under "Omnibus Agreement."

Relationships with SBG

A former director, Phil Gisi, was also a director and executive officer of SBG Energy Services, LLC ("SBG"), and Creek Energy Services, LLC ("Creek" - formerly Rud Transportation LLC), an affiliate of SBG. As discussed below, we have commercial arrangements with SBG, SBG Disposal ("SBG Disposal") LLC and Creek, and we believe the terms of these transactions are similar to what would have been obtained from an unaffiliated third party.

SBG Management Services Agreement

On December 31, 2012, Holdings, acting through one of its subsidiaries, entered into a management services agreement with SBG Disposal. Pursuant to this agreement, SBG Disposal provided day-to-day oversight, management, development, construction and operations of the SWD facilities we acquired from SBG. Effective October 1, 2013, SBG Disposal contributed this agreement to CES LLC, which was owned 49.0% by SBG Disposal prior to our acquisition of the 49% interest on June 1, 2015. All personnel providing such services became employees of Cypress Energy Management – Bakken Operations, LLC, a wholly owned subsidiary of CEM LLC, on December 22, 2013. This agreement has a five year term that will automatically renew for 90 day periods unless terminated by either party with written notice. Prior to the contribution of the management agreement, SBG Disposal was paid a monthly fee equal to 4.75% of gross revenues in addition to reimbursable expenses such as direct staffing expenses and supplies.

SBG Option Agreement

On December 31, 2012, CEP LLC, acting through a subsidiary, entered into an option agreement with SBG. Pursuant to this agreement, SBG, the sole member of SBG Disposal, granted CEP LLC the option to purchase 51.0% of the membership interests in SBG Disposal for $500,000. On December 6, 2013, CEP LLC, acting through a subsidiary, effectively exercised this option by entering into an asset contribution and assumption agreement with SBG Disposal, or the asset contribution agreement, through which SBG Disposal conveyed certain of its assets, including all fixed assets, to CES LLC in exchange for a 49.0% membership interest in CES LLC prior to our acquisition of the 49% interest on June 1, 2015 and a cash payment from CES LLC of $500,000. This transaction was effective October 1, 2013. The assets contributed included a 25.0% non-controlling interest in an SWD facility in Watford City, North Dakota and five management services agreements related to SBG Disposal's management of ten SWD facilities in North Dakota, eight of which we own. CES LLC is consolidated in our financial statements beginning October 1, 2013.

SBG Omnibus Option Agreement

On December 31, 2012, Holdings, acting through one of its subsidiaries, entered into an omnibus option agreement with SBG and its owners, including Philip Gisi (a former member of the board of directors of our general partner). Pursuant to this agreement, Holdings has the first right to negotiate with the owners of SBG if they decide to sell the membership interest in SBG. The agreement also provides Holdings with the first right to negotiate with SBG if SBG decides to sell any of the following assets:

- its membership interest in Creek, a wholly owned subsidiary of SBG that owns trucking equipment engaged in hauling water to and from producers in North Dakota;

- all of SBG’s right to any water pipeline construction, development or acquisition opportunity;

- all of SBG’s interest in its gas and diesel wholesale venture; and

- all of SBG’s interest in its hot water and rail spur ventures.

Holdings also acquired the right to purchase certain other assets that it does not currently anticipate exercising.

Effective July 1, 2015, the Partnership waived its rights to purchase and its rights of first refusal related to certain SWD assets pursuant to this option agreement with SBG Energy in exchange for $1.0 million. The $1.0 million payment has been reflected as *gain on waiver of right of purchase other, net* on the Consolidated Statements of Operations for the year ended December 31, 2015.

Mr. Boylan's Sharing Interest in Holdings

In connection with the formation of Holdings, as a co-founder, Mr. Boylan, our Chairman, Chief Executive Officer and President was issued a limited liability company interest in Holdings, based upon his arms' length negotiation with Charles C. Stephenson, Jr., the other co-founder of Holdings. The terms of Mr. Boylan's limited liability company interest provided that Mr. Boylan initially receive a 5.0% sharing interest in the profits and losses of Holdings and in any distributions made by Holdings in respect of its equity securities, which sharing interest increasing to 24.50% effective on the earlier of April 1, 2015 or the IPO of our equity securities. As a result, Mr. Boylan's sharing interest in Holdings was increased to 24.50% (25% prior to admission of Henry Cornell) in connection with the consummation of the IPO.

Procedures for Review, Approval and Ratification of Related Person Transactions

The board of directors of our general partner adopted a related party transactions policy in connection with the closing of the IPO that provides that the board of directors of our general partner or its authorized committee will review on at least a quarterly basis all related person transactions that are required to be disclosed under SEC rules and, when appropriate, initially authorize or ratify all such transactions. In the event that the board of directors of our general partner or its authorized committee considers ratification of a related person transaction and determines not to so ratify, the code of business conduct and ethics will provide that our management will make all reasonable efforts to cancel or annul the transaction.

The related party transactions policy provides that, in determining whether or not to recommend the initial approval or ratification of a related person transaction, the board of directors of our general partner or its authorized committee should consider all of the relevant facts and circumstances available, including (if applicable) but not limited to: (1) whether there is an appropriate business justification for the transaction; (2) the benefits that accrue to us as a result of the transaction; (3) the terms available to unrelated third-parties entering into similar transactions; (4) the impact of the transaction on a director's independence (in the event the related person is a director, an immediate family member of a director or an entity in which a director or an immediate family member of a director is a partner, shareholder, member or executive officer); (5) the availability of other sources for comparable products or services; (6) whether it is a single transaction or a series of ongoing, related transactions; and (7) whether entering into the transaction would be consistent with the code of business conduct and ethics.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

We have engaged Ernst & Young LLP as our independent registered public accounting firm. The following table sets forth fees we have paid to Ernst & Young LLP for the years ended December 31, 2016, and 2015 and 2014.

	Years Ended December 31,		
Audit and Non-Audit Fees	**2016**	**2015**	**2014**
Audit fees (a)	$ 663	$ 870	$ 959
Audit-related fees (b)	—	70	28
Tax fees (c)	283	194	303
All other fees	—	—	—
Total	$ 946	$ 1,134	$ 1,290

(a) Fees for audit services include fees associated with the annual audit of Cypress Energy Partners, L.P. and reviews of the Partnership’s quarterly reports.
(b) Includes fees related to acquisition due diligence and accounting consultations.
(c) Includes fees for tax services for Cypress Energy Partners, L.P. and affiliates in connection with tax compliance, tax advice and tax planning.

Audit Committee Pre-Approval Policies and Procedures

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

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Documents to be filed as part of this Annual Report

1. A list of the financial statements included in this Annual Report on Form 10-K is set forth in Part II, Item 8 of this Annual Report on Form 10-K.

2. Financial Statement Schedules: Financial Statement Schedules are omitted because they are not required, not significant, not applicable or the information is shown in another schedule, the financial statements or the notes to Consolidated Financial Statements.

3. Exhibits: See "*Exhibit Index*" below.

Exhibit Index

Exhibit number	Description
2.1	Contribution, Conveyance and Assumption Agreement, dated February 20, 2015, by and among Cypress Energy Holdings, LLC, Cypress Energy Partners, LLC, Cypress Energy Partners, L.P., Cypress Energy Partners GP, LLC, Cypress Energy Partners – TIR, LLC, Mr. Charles C. Stephenson, Jr. and Ms. Cynthia A. Field (incorporated by reference to Exhibit 2.1 of our Current Report on Form 8-K filed on February 23, 2015)
3.1	First Amended and Restated Agreement of Limited Partnership of Cypress Energy Partners, L.P. dated as of January 21, 2014 (incorporated by reference to Exhibit 3.1 of our Current Report on Form 8-K filed on January 27, 2014)
3.2	Certificate of Formation of Cypress Energy Partners GP, LLC (incorporated by reference to Exhibit 3.5 of our Registration Statement on Form S-1/A filed on December 17, 2013)
3.3	Amended and Restated Limited Liability Company Agreement of Cypress Energy Partners GP, LLC dated as of January 21, 2014 (incorporated by reference to Exhibit 3.2 of our Current Report on Form 8-K filed on January 27, 2014)
3.4	Certificate of Limited Partnership of Cypress Energy Partners, L.P. (incorporated by reference to Exhibit 3.7 of our Registration Statement on Form S-1/A filed on December 17, 2013)
10.1†	Cypress Energy Partners, L.P. 2013 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 of our Current Report on Form 8-K filed on January 27, 2014)
10.2†	Form of Cypress Energy Partners, L.P. 2013 Long-Term Incentive Plan Phantom Unit Agreement (incorporated by reference to Exhibit 10.4 of our Registration Statement on Form S-1/A filed on December 17, 2013)

10.3	Credit Agreement, dated as of December 24, 2013 between Cypress, as borrower, certain of its affiliates as co-borrowers and guarantors, Deutsche Bank AG, New York Branch, as a lender, swing line lender and collateral agent, the other lenders from time to time party thereto, and Deutsche Bank Trust Company Americas, as the administrative agent (incorporated by reference to Exhibit 10.5 of our Registration Statement on Form S-1/A filed on January 10, 2014)
10.4	Amendment No. 1 to Credit Agreement, dated as of October 21, 2014 between Cypress, as borrower, certain of its affiliates as co-borrowers and guarantors, Deutsche Bank AG, New York Branch, as collateral agent, lender, issuing bank and swing line lender, the other lenders from time to time party thereto, and Deutsche Bank Trust Company Americas, as the administrative agent (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed on October 24, 2014)
10.5	Amended and Restated Omnibus Agreement, dated February 20, 2015, among Cypress Energy Holdings, LLC, Cypress Energy Management, LLC, Cypress Energy Partners, LLC, Cypress Energy Partners, L.P., Cypress Energy Partners GP, LLC, Cypress Energy Partners – TIR, LLC, Tulsa Inspection Resources, LLC, Tulsa Inspection Resources – Canada ULC, Tulsa Inspection Resources Holdings, LLC and Tulsa Inspection Resources – Nondestructive Examination, LLC (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed on February 23, 2015)

10.6	Amendment No. 2 to Credit Agreement, dated May 4, 2015, by and among Cypress Energy Partners, L.P., Cypress Energy Partners – TIR, LLC, Cypress Energy Partners, LLC and Tulsa Inspection Resources, LLC, as borrowers, Tulsa Inspection Resources – Canada ULC, the guarantors party thereto, Deutsche Bank AG, New York Branch, in its capacity as collateral agent and as a lender, issuing bank and swing line lender, Deutsche Bank Trust Company Americas, in its capacity as administrative agent, and the several banks and other financial institutions or entities from time to time parties thereto (incorporated by reference to Exhibit 10.1 of our Current Report on Form 8-K filed on May 7, 2015)
21.1*	List of Subsidiaries of Cypress Energy Partners, L.P.
23.1*	Consent of Ernst & Young LLP
31.1*	Chief Executive Officer Certification Pursuant to Exchange Act Rule 13a-14(a) or Rule 15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Chief Financial Officer Certification Pursuant to Exchange Act Rule 13a-14(a) or Rule 15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1**	Chief Executive Officer Certification Pursuant to Exchange Act Rule 13a-14(b) or Rule 15d-14(b) and Section 1350 of Chapter 63 of Title 18 of the United States Code, as Adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.1**	Chief Financial Officer Certification Pursuant to Exchange Act Rule 13a-14(b) or Rule 15d-14(b) and Section 1350 of Chapter 63 of Title 18 of the United States Code, as Adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101 INS*	XBRL Instance Document
101 SCH*	XBRL Schema Document
101 CAL*	XBRL Calculation Linkbase Document
101 DEF*	XBRL Definition Linkbase Document
101 LAB*	XBRL Label Linkbase Document
101 PRE*	XBRL Presentation Linkbase Document

* Filed herewith.
** Furnished herewith.
† Management contract or compensatory plan or arrangement.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Tulsa, State of Oklahoma, on March 15, 2017.

Cypress Energy Partners, L.P.

By: Cypress Energy Partners GP, LLC, its general partner

/s/ G. Les Austin
By: G. Les Austin
Title: Chief Financial Officer

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

Signature	**Title**	**Date**
/ s/ Peter C. Boylan III Peter C. Boylan III	Chief Executive Officer and Chairman of the Board	March 15, 2017
/ s/ G. Les Austin G. Les Austin	Chief Financial Officer and Treasurer (Principal Financial Officer and Principal Accounting Officer)	March 15, 2017
/ s/ Henry Cornell Henry Cornell	Director	March 15, 2017
/ s/ Stanley A. Lybarger Stanley A. Lybarger	Director	March 15, 2017
/ s/ John T. McNabb II John T. McNabb II	Director	March 15, 2017
/ s/ Charles C. Stephenson, Jr.	Director	March 15, 2017

Charles C. Stephenson, Jr.

136