Emerge Energy Services LP
Form 10-K
February 29, 2016
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

ý ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2015

OR

¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

Commission File No. 001-35912

EMERGE ENERGY SERVICES LP
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	90-0832937 (I.R.S. Employer Identification No.)
180 State Street, Suite 225, Southlake, Texas 76092 (Address of principal executive offices)	(817) 865-5830 (Registrant’s telephone number, including area code)

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

Title of Each Class	Name of Each Exchange On Which Registered
Common Units Representing Limited Partner Interests	New York Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. o Yes ý 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. o Yes ý 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. ý Yes o 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 (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). ý Yes o 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 registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. o

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 x Accelerated Filer o Non-Accelerated Filer o Smaller Reporting Company o

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

As of June 30, 2015, the last business day of the registrant's second fiscal quarter of 2015, the aggregate market value of the registrant's common units held by non-affiliates of the registrant was $576,511,116 based on the closing price as reported on the New York Stock Exchange composite tape on that date.

As of February 22, 2016, 24,121,222 common units were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE: None

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CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Certain statements and information in this Annual Report on Form 10-K may constitute "forward-looking statements." The words "believe," "expect," "anticipate," "plan," "intend," "foresee," "should," "would," "could" or other similar expressio intended to identify forward-looking statements, which are generally not historical in nature. These forward-looking statements are based on our current expectations and beliefs concerning future developments and their potential effect on us. While management believes that these forward-looking statements are reasonable as and when made, there can be no assurance that future developments affecting us will be those that we anticipate. All comments concerning our expectations for future revenues and operating results are based on our forecasts for our existing operations and do not include the potential impact of any future acquisitions. Our forward-looking statements involve significant risks and uncertainties (some of which are beyond our control) and assumptions that could cause actual results to differ materially from our historical experience and our present expectations or projections. Known material factors that could cause our actual results to differ from those in the forward-looking statements are those described in Part I, Item 1A. Risk Factors.

Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. We undertake no obligation to publicly update or revise any forward-looking statements after the date they are made, whether as a result of new information, future events or otherwise.

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GLOSSARY OF SELECTED TERMS

16/30 frac sand: Sand that passes through a sieve with 16 holes per linear inch (16 mesh) and is retained by a sieve with 30 holes per linear inch (30 mesh).

20/40 frac sand: Sand that passes through a sieve with 20 holes per linear inch (20 mesh) and is retained by a sieve with 40 holes per linear inch (40 mesh).

30/50 frac sand: Sand that passes through a sieve with 30 holes per linear inch (30 mesh) and is retained by a sieve with 50 holes per linear inch (50 mesh).

40/70 frac sand: Sand that passes through a sieve with 40 holes per linear inch (40 mesh) and is retained by a sieve with 70 holes per linear inch (70 mesh).

100 mesh frac sand: Sand that passes through a sieve with 100 holes per linear inch (100 mesh).

Acid solubility: A measure of how easily a substance dissolves into a low pH liquid solvent. Generally, the lower the acid solubility of a proppant, the more likely it is to retain its integrity when subjected to a low pH environment, which is often encountered in hydraulic fracturing of high-sulfur crude oil and natural gas deposits.

API: American Petroleum Institute.

Backwardation: A market situation in which the futures price of a commodity is below the expected future spot price. Contango is the opposite market condition.

Barrel: An amount equal to 42 gallons.

Biodiesel: A domestic, renewable fuel for diesel engines derived from natural oils, and which is comprised of mono-alkyl esters of long chain fatty acids derived from vegetable oils or animal fats, designated B-100 and meeting the requirements of ASTM D 6751, “Standard Specification for Biodiesel Fuel (B-100) Blend Stock for Distillate Fuels.”

Ceramics: Artificially manufactured proppants of consistent size and sphere shape that offers a high crush strength.

Contango: A market situation in which the futures price of a commodity is higher than the expected future spot price. The opposite market condition is backwardation.

Crush strength: Ability to withstand high pressures. Crush strength is measured according to the pounds per square inch of pressure that can be withstood before the proppant breaks down into finer granules.

Conductivity: A measure of how well a substance travels in a liquid medium. Generally, the smoother the surface of a proppant, the further it can travel when carried in a fracking solution to penetrate fissures in the source rock.

Dry plant: An industrial site where slurried sand product is fed through a dryer and screening system to be dried and screened in varying size gradations. The finished product that emerges from the dry plant is then stored in silos or stockpiles before being transported to customers or is immediately loaded onto a conveyance for transportation.

Frac sand: A proppant used in the completion and re-completion of oil and natural gas wells to stimulate and maintain oil and natural gas production through the process of hydraulic fracturing.

GAAP: Generally accepted accounting principles in the United States.

Hydraulic fracturing: The process of pumping fluids, mixed with granular proppants, into a geological formation at pressures sufficient to create fractures in the hydrocarbon-bearing rock.

Hydrotreater: A processing unit that removes sulfur and other impurities from raw or refined hydrocarbons through a catalyst or other means that combines the impurities with hydrogen. The resulting byproducts are then removed from the hydrocarbon stream, through a combination of temperature and pressure, and recycled.

ISO: International Organization for Standardization.

Low sulfur diesel: Diesel fuel that has a sulfur content of greater than 15 ppm and a maximum sulfur content of 500 ppm.

mcf. One thousand cubic feet of natural gas.

Mesh size: Measurement of the size of a grain of sand indicating it will pass through a sieve of a certain size.

Northern White sand: A monocrystalline sand with greater sphericity, roundness and low acid solubility, enabling higher crush strengths and conductivity, which is found primarily in Wisconsin's Jordan, Mt. Simon, St. Peter and Wonewoc formations.

Overburden: Layers of soil, clay and other waste covering a mineral deposit.

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ppm: Parts per million.
Proppant: A sized particle mixed with fracturing fluid to hold fractures open after a hydraulic fracturing treatment.
Re-fracking: The practice of returning to older shale oil and gas wells that had been hydraulic fractured in the recent past to capitalize on newer and more effective extraction technology.
Renewable Identification Numbers (“RINs”): Serial numbers assigned to batches of biofuel for the purpose of tracking its production, use, and trading as required under Energy Independence and Security Act of 2007.
Reserves: Natural resources, including sand, that can be economically extracted or produced at the time of determination based on relevant legal, economic and technical considerations.
Resin-coated sand: Raw sand that is coated with a flexible resin that increases the sand's crush strength and prevents crushed sand from dispersing throughout the fracture.
Roundness: A measure of how round the curvatures of an object are. The opposite of round is angular. It is possible for an object to be round but not spherical (e.g., an egg-shaped particle is round, but not spherical). When used to describe proppant, roundness is a reference to having a curved shape which promotes hydrocarbon flow, as the curvature creates a space through which the hydrocarbons can flow.
Sphericity: A measure of how well an object is formed in a shape where all points are equidistant from the center. The more spherical a proppant, the more highly conductive it is because it creates larger gaps that promote maximum hydrocarbon flow.
Shale Play: A geological formation that contains petroleum and/or natural gas in nonporous rock that requires special drilling and completion techniques.
Transmix: The liquid interface, or fuel mixture, that forms in refined product pipelines between batches of different fuel types.
Turbidity: A measure of the level of contaminants, such as silt and clay, in a sample.
Ultra low sulfur diesel: Diesel Fuel that has a maximum sulfur content of 15 ppm.
Unit train: A train in which all of its cars are shipped from the same origin to the same destination, without being split up or stored en route.
Wet plant: An industrial site where quarried sand is fed through a stone breaking machine, crusher system and then slurried into the plant. The sand ore is then scrubbed and hydrosized by log washers or rotary scrubbers to remove the deleterious materials from the ore, and then separated using a vibrating screen and waterway system to generate separate 100 mesh and +70 mesh stockpiles, providing a uniform feedstock for the dryer. The ultra-fine materials are typically sent to a mechanical thickener, and eventually to settling ponds.

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PART I

ITEM 1. BUSINESS

Emerge Energy Services LP ("Emerge") is a Delaware limited partnership that completed its initial public offering ("IPO") on May 14, 2013 to become a publicly traded partnership. The combined entities of Superior Silica Sands LLC ("SSS"), a Texas limited liability company, and Allied Energy Company LLC ("AEC"), an Alabama limited liability company, represent the predecessor for accounting purposes (the "Predecessor") of Emerge.

Immediately prior to the closing of the IPO, Insight Equity Management Company LLC and its affiliated investment funds and its controlling equity owners, Ted W. Beneski and Victor L. Vescovo (collectively "Insight Equity") conveyed all of the interests in SSS and AEC to the Partnership as a capital contribution, and the Partnership conveyed its interests in SSS and AEC to the Partnership's subsidiary Emerge Energy Services Operating LLC ("Emerge Operating"), a Delaware limited liability company. In addition, the Partnership formed Emerge Energy Distributors Inc. ("Distributor"), a Delaware corporation, and purchased Direct Fuels LLC ("Direct Fuels"), a Delaware limited liability company, through a combination of cash, issuance of common units, and assumption of debt, and the Partnership conveyed all of the interest in Direct Fuels to Emerge Operating. Therefore, the historical financial statements contained in this Form 10-K reflect the combined assets, liabilities and operations of the Partnership, SSS and AEC for periods ending before May 14, 2013 and the assets, liabilities and operations of the Partnership and all of its subsidiaries for periods beginning on or after May 14, 2013.

References to the "Partnership," "we," "our" or "us" when used for dates or periods ended prior to the IPO, refer collectively to the Predecessor. References to the "Partnership," "we," "our" or "us" when used for dates or periods ended on or after the IPO, refer collectively to Emerge and all of its subsidiaries.

Overview

We are a publicly-traded limited partnership formed in 2012 by management and affiliates of Insight Equity to own, operate, acquire, and develop a diversified portfolio of energy service assets.

Our current operations are organized into two service-oriented business segments: our Sand segment and our Fuel segment. Through our Sand segment, we are engaged in the businesses of mining, processing, and distributing silica sand, a key input for the hydraulic fracturing of oil and natural gas wells. Our Fuel segment processes transmix, distributes refined motor fuels and renewable fuels, operates bulk motor fuel storage terminals, and provides complementary services. We believe this diverse set of operations provides a stable cash flow profile when compared to companies with only one line of business. For more detailed financial information regarding our Sand and Fuel segments, see Item 8. Financial Statements and Supplementary Data — Note 16. Segment Information and Geographical Data.

We conduct our Sand operations through our subsidiary SSS and our Fuel operations through our subsidiaries Direct Fuels, AEC, and Distributor. We believe that our subsidiary brands, especially our SSS brand, have significant name recognition and a strong reputation with our customers.

Our principal offices are located at 180 State Street, Suite 225, Southlake, Texas 76092. Our telephone number is (817) 865-5830 and our website address is www.emergelp.com.

Business Strategies

The primary components of our business strategy are:

- Focus on profitability and improving financial condition. We are applying financial discipline to all aspects of our business with the primary goals of reducing costs, minimizing capital expenditures, restructuring our long-term lease commitments, realigning our human resource capital, idling our most expensive plants, working to reduce our bank debt, coordinating with our bank group to modify lending covenants, and accelerating the introduction of technology-based sand products that could improve our financial performance. These strategy efforts include, but are not limited to:
- negotiate with our suppliers to reduce costs associated with other goods and services;
- reduce our capital expenditures and cancel planned expansion projects that are no longer economically feasible in this deteriorating market;
- negotiate with key railcar lessors to delay future deliveries and reduce future lease costs;

- continue to reduce employee headcount to more closely align our human capital with current levels of sales;

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- temporarily idle our most expensive dry plant at Arland, and the wet plant at New Auburn;
- explore strategic sale transactions, such as the possible sale of our Fuel segment and the application of the net proceeds to reduce bank debt;
- renegotiate bank lending covenants in connection with a possible sale of our Fuel segment;
- expand sales of our dustless proppant, SandGuard™, which we believe will result in higher profit margins; and
- introduce, after satisfactory testing, our self-suspending proppant, SandMaxx™, which we also believe will result in higher profit margins.

- Optimize existing assets. We intend to focus on efforts that complement our existing asset base or provide attractive returns in new geographic areas or business lines. In our Sand segment, we have three Northern White dry plant facilities located in Wisconsin and an additional dry plant facility located in Kosse, TX. To reduce costs, we have temporarily idled our most expensive dry plant at Arland and the wet plant at New Auburn to run our lowest cost plants at higher capacity. In our Fuel segment, we believe there are several opportunities to contract additional transmix supplies which we can process using existing excess capacity, and increase both wholesale, and terminal volumes. We are also building hydrotreaters at our two fuel terminals to allow us to process low sulfur transmix into ultra-low sulfur diesel. We expect those hydrotreaters to be completed in 2016.
- Introduce new products serving our core end users. We intend to increase our presence and market share in frac sand end markets that we believe are poised for growth. In September 2015, we introduced a unique, technically advanced proppant to the oil and gas industry. This new dustless proppant, brand named SandGuard™, will improve the handling, in-basin management, and job-site implementation of the hydraulic fracturing of oil and gas wells. With a SandGuard™ treatment facility in Barron County, Wisconsin, SSS will have the ability to enhance the already strong qualities of its Northern White silica sand as a patent protected proppant soon to be marketed to all major North American basins.

We are also developing a self-suspending proppant ("SSP") through the SandMaxx™ brand. By utilizing a patented polymer coating system designed for application to sand substrate, we developed a product with a coating material that, when mixed with water for hydraulic fracturing, suspends proppant in the frac fluid, thereby slowing the settling rate and enabling the proppant to flow farther into oil and gas reservoir fissures. We expect to introduce our SSP product to the market through field trials by the end of the second quarter of 2016. The SandMaxx™ product used for initial laboratory and field testing was produced in a small supplementary production circuit added to the Barron facility.

- Focus on customer contracts. In our Sand segment, we are working to secure long-term take-or-pay, fixed-volume, and efforts-based contracts with existing and new customers in order to cover the substantial majority of our production capacity. In 2015, total sales to customers currently under long-term contracts, including efforts-based, fixed-volume, and take-or-pay arrangements, accounted for 83% of our total Sand segment sales. As of December 31, 2015, we had 7.5 million tons under long-term contract, primarily efforts-based arrangements, with a weighted average remaining of four years. In our Fuel segment, we designed our contract structure to capture a stable margin, as the price differential between the refined products indices at which we purchase transmix and wholesale fuel and the ultimate selling price of the corresponding refined product. We also seek to lease additional space in our terminal tanks to refiners and large fuel wholesalers, where we can capture both fixed monthly fees and fixed per-gallon throughput margins that are independent of the underlying commodity price. We also engage in financial hedging arrangements to partially mitigate, but not eliminate, our direct exposure to fuel commodity price fluctuations.
- Capitalize on industry fundamentals. The demand for frac sand decreased in 2015 as North American drilling activity declined in response to falling oil and gas prices. Rig count reductions were partially offset by a higher number of wells drilled per operating rig and an increase in sand intensity per well drilled. Although the timeline for a recovery of drilling and fracking activity remains uncertain, we continue to believe the frac sand market offers attractive long-term growth fundamentals.
- Grow business through strategic and accretive business or asset acquisitions. Financial performance and condition permitting, we plan to selectively pursue accretive acquisitions in our areas of operation that we believe will allow us to realize operational efficiencies by capitalizing on our existing infrastructure, personnel and commercial relationships in energy services, and we may also seek acquisitions in new geographic areas or complementary business lines. In December 2015, we acquired the rights to mine approximately 94 million tons of high quality

northern white silica sand reserves in Jackson County, Wisconsin. The sand reserve figure is based upon internal analysis of drilling and coring samples. This transaction not only provides us with future access to high quality sand reserves, but also strengthens our position in the marketplace with a leading pressure pumper across a number of shale plays in North America. Given the current

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challenging market conditions for proppant demand, we have deferred the construction of a new facility to support these newly acquired reserve rights until the North American oil and gas markets improve and our financial condition allows.

- Distributions. While Amendment No. 2 to the Amended and Restated Revolving Credit and Security Agreement limits our ability to make distributions to our unitholders, our board of directors of our general partner remains committed to resuming distributions as our financial condition allows.

Competitive Strengths

We believe that we are well positioned to successfully execute our business strategies because of the following competitive strengths:

- High quality, strategically located assets. We currently operate several scalable frac sand production facilities in and around Barron County, Wisconsin and Kosse, Texas. Our facilities in Wisconsin are supported by approximately 75 million tons of proven recoverable sand reserves and our facility in Texas is supported by approximately 27.4 million tons of proven recoverable sand reserves. We believe that our Wisconsin and Texas reserves provide us access to a balanced amount of coarse sand (16/30, 20/40, and 30/50 mesh sands) and fine sand (40/70 and 100 mesh) compared to other frac sand producers. Our sample boring data and production data indicated that our Wisconsin reserves contain deposits of nearly 35% 40 mesh or coarser substrate, with our Barron reserves being comprised of more than 60% 50 mesh or coarser substrate. Our mine deposits in Wisconsin can be targeted to extract finer grades when the market dictates such demand is wanted, as is the current trend. Also, our Kosse, TX operation primarily consists of fine sand product, which affords us significant flexibility of serving our customers with their desired product type needs.

Our transmix facilities are centrally located in the Dallas-FortWorth and Birmingham metropolitan areas. Because pipelines typically represent the most economical means of transporting petroleum products, proximity to refined products pipelines is critical to the economic success of our transmix, wholesale, and terminal operations. We are able to receive products via two different pipelines owned by the Explorer Pipeline Company and one pipeline owned by a major independent refiner at our facility in the Dallas-Fort Worth metropolitan area, and via the Plantation and Colonial pipelines at our Birmingham facility.

- Logistics. In our Sand segment, the logistics capabilities of our Wisconsin facilities enable us to serve all major United States and Canadian oil and natural gas producing basins, as well as provide us with economical access to Mexico and South America. Our New Auburn facility is connected to a rail line owned by Union Pacific, and our Barron facility is connected to the Canadian National rail line. Between our two Wisconsin rail yards, we have storage space for approximately 1,000 railcars. Our Baron and New Auburn dry plant facilities can accommodate unit trains. As of December 31, 2015, we had a total of 5,657 railcars in our fleet, including 326 dedicated customer cars and 5,331 railcars under lease with a weighted average remaining term of 4.7 years. As of December 31, 2015, we had 15 transload facilities in North America, each of which is positioned to serve a number of our target markets.
- Competitive operating cost structure. We believe that our operations are characterized by an overall low cost structure which allows us to capture attractive margins in the industries in which we operate. Our low cost structure is a result of the following key attributes:
- close proximity of our silica sand reserves to our processing plants, which reduces operating costs;
- expertise in designing, building, maintaining and operating advanced frac sand processing, storage and loading facilities, operating transmix plants, and managing fuel storage assets;
- a large proportion of the costs we incur in our production of sand are only incurred when we produce saleable frac sand;
- open dialogue with key vendors allowing for cost reduction in down markets;
- proximity to major sand and fuel logistics infrastructure, minimizing transportation and fuel costs, and headcount needs;
- competitive mineral royalty expenses;
- enclosed dry plant operations which allow full run rates during winter months, thereby increasing plant utilization; and
- a diversified and growing customer base spread across nearly every major shale play in North America.

In addition to these capabilities, we are taking a number of proactive steps to further lower our operating costs, including de-bottlenecking our Kosse, Texas facilities, refining our mining techniques at our Barron county mines and wet plants, and incentivizing customers to put more volumes through our transload locations. We began using new mining techniques at two of our Wisconsin mines in the third quarter of 2015, and plan to introduce these techniques to our Kosse mine in

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the near term. We also introduced new processing techniques at our Kosse plant in the third quarter of 2015 that allowed us to inexpensively extract significant amounts of saleable frac sand from previously mined and discarded waste streams.

- Strong reputation with our customers, suppliers and other constituencies. Our management and operating teams have developed longstanding relationships with our customers, suppliers, and other constituencies. Based on our track record of dependability, timely delivery and high-quality products that consistently meet customer specifications, we believe that we are well positioned to secure additional contracted commitments in the future, and that our product mix and customer service will continue to benefit our reputation within the frac sand industry. In our Fuel segment, we have established long-term supply relationships with major refining, midstream and marketing companies that provide us with a steady source of supply at competitive prices.
- Experienced management team with industry specific operating and technical expertise. The senior management team at our Sand segment has extensive industry experience in managing and operating industrial mineral production facilities. They have managed numerous frac sand mining and processing plants, and successfully led acquisitions in the industry and developed multiple greenfield industrial mineral processing facilities. Most recently, this management team commissioned the Arland facility that was designed, permitted, and entered production on an expedited timeline. We believe that our customers value our commitment to customer service, our reliable delivery, and our focus on high-quality product. The senior management team members at our Fuel segment have significant industry experience and complementary skills in the areas of transmix processing, acquiring, integrating, financing, and managing refined product terminals.

Our Business Segments

Sand Segment

Our Sand segment mines, processes and distributes high quality silica sand, a key input for the hydraulic fracturing of oil and gas wells. Our Wisconsin facilities consist of three dry plants located in Arland, Barron and New Auburn, Wisconsin with a total permitted capacity of 6.3 million finished tons per year, and five wet plants and mine complexes that supply the dry plants with Northern White silica sand, which we believe is the highest quality raw frac sand available. We also have a fourth dry plant in Kosse, Texas, with a capacity of 600,000 tons per year that is supplied by a separate mine and wet plant that processes local Texas sand. As of December 31, 2015, we also had 15 transload facilities located throughout North America in the key basins where we deliver our sand, as well as a fleet of 5,657 railcars.

Our Sand segment has experienced rapid growth within the past several years due to technological advances in horizontal drilling and the hydraulic fracturing process that have made the extraction of large volumes of oil and natural gas from domestic unconventional hydrocarbon formations economically feasible. We believe that the premium geologic characteristics of our Wisconsin sand reserves, the strategic location of our sand mines, our location on multiple Class One rail lines, our extensive transload and logistics network, the industry experience of our senior management team, and the reputation that SSS has with our customers position us as a highly attractive source of frac sand to the oil and natural gas industry.

The production of our sand consists of three basic processes: mining, wet plant operations, and dry plant operations. All mining activities take place in an open pit environment, whereby we remove the topsoil, which is set aside, and then remove other non-economic minerals, or “overburden,” to expose the sand deposits. We then “bump” the sand using explosives on the mine face, which causes the sand to fall into the pit, where it is then carried by truck to the wet plant operations. We also utilize a process called hydraulic mining whereby we use high pressure water cannons to dislodge the sandstone, and transport the sand and water mixture via pipeline to the wet plant. Where the geology is suitable, this technique minimizes the use of heavy excavation machinery, thereby lowering operating costs. Once we have mined out a portion of the reserves, we then either return the land to its previous contours or to a more usable contour, and then replace the topsoil. At our wet plant, the mined sand goes through a series of processes designed to separate the sand from unusable materials. The resulting wet sand is then conveyed to a wet sand stockpile where most of the water is allowed to drain into our on-site recycling facility, while the remaining fine grains and other materials, if any, are separated through a series of settlement ponds. We reuse all of the water that does not evaporate in our wet process. Wet sand from our stockpile is then conveyed or trucked to our dry plants where the sand is dried, screened into specific mesh categories, and stored in silos. From the silos, we load sand directly into railcars or trucks, which we then ship to one of our transload facilities or directly to one of our customers.

Our frac sand facilities are located in Barron County and Chippewa County, Wisconsin and Kosse, Texas. Based on the reports of third-party independent engineering firms, we have approximately 102.4 million tons of proven recoverable reserves, excluding an estimated 94 million tons of reserve rights acquired in December 2015. We are currently capable of producing up to 8.8 million tons and 6.9 million tons of wet and dry sand per year, respectively, from our current facilities. We believe that the coarseness, conductivity, sphericity, acid-solubility and crush-resistant properties of our Wisconsin reserves and our facilities' connectivity to rail and other transportation infrastructure afford us an advantage over our competitors and make us one of a select group of sand

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producers capable of delivering high volumes of frac sand that is optimal for oil and natural gas production to all major unconventional resource basins currently producing throughout North America and abroad.

Our Wisconsin sand reserves give us access to a range of high-quality sand that meets or exceeds all API specifications and includes a mix between concentration of coarse grades (16/30, 20/40 and 30/50 mesh sands) and finer grades (40/70 and 100 mesh). While our Wisconsin reserves provide us access to a high amount of coarse sand compared to other Northern White deposits located in Wisconsin's Jordan, St. Peter, and Wonewoc formations, we have the ability to target certain locations in our deposits to obtain finer sands. Our sample boring data and our historical production data have indicated that our Wisconsin reserves contain deposits of nearly 35% 40 mesh or coarser substrate, with our Arland, Church Road, LP Mine and Thompson Hills reserves being comprised of more than 60% 50 mesh or coarser substrate. We are also one of a select number of mine operators that can offer commercial amounts of 16/30 mesh sand, the coarsest grade of widely-used frac sand on the market. Our Wisconsin dry plants are fully enclosed, which means that we are capable of running year-round, regardless of the weather. Under normal market conditions, we operate our Wisconsin plants with work crews of four to six employees. These crews work 40-hour weeks, with shifts between eight and twelve hours, depending on the employee's function. Because raw sand cannot be wet-processed during extremely cold temperatures, we typically mine and wet-process frac sand eight months out of the year at our Wisconsin locations.

Our mine, wet plant, and dry plant in Kosse, Texas operate year-round. The reserves primarily consist of finer mesh grades, which strategically complement the coarser grades from our Wisconsin deposits. We operate our Kosse facilities with crews of four to six employees who work twelve-hour shifts and average 40 hours per week. This allows us to optimize facility utilization.

Each of our facilities undergoes regular maintenance to minimize unscheduled downtime, and to ensure that the quality of our frac sand meets applicable ISO and API standards and our customers' specifications. In addition, we make capital investments in our facilities as required to support customer demand, and our internal performance goals.

The following table provides information regarding our frac sand production facilities as of December 31, 2015.

Wet Plant Location (1)	Proven Recoverable Reserves (Millions of Tons) (2)	Lease Expiration Date (3)	Annual Plant Capacity (Thousands of Tons)	2015 Production (Thousands of Tons)
New Auburn	15.5	March 2036	2,000	755
Thompson Hills	38.5	December 2037	1,600	699
FLS Mine	10.2	July 2037	1,200	779
Church Road	5.3	N/A	1,200	604
LP Mine	5.5	March 2038	1,200	603
Kosse, TX	27.4	N/A	1,600	441
Dry Plant Location (1)		On-site Railcar Storage Capacity (4)	Annual Plant Capacity (Thousands of Tons)	2015 Production Volumes (Thousands of Tons)
Arland		N/A	2,500	1,064
Barron		650 cars	2,400	1,536
New Auburn		420 cars	1,400	604
Kosse, TX		N/A	600	277

(1) All facilities are located in Wisconsin, except for our Kosse facility. In January 2016, we temporarily idled our Arland dry plant, and we temporarily idled our mining operations at the New Auburn wet plant.

(2) Reserves are estimated as of December 31, 2015 by third-party independent engineering firms based on core drilling results and in accordance with the SEC’s definition of proven recoverable reserves and related rules for companies engaged in significant mining activities and represent marketable finished product.

(3) We own the land and mineral rights at our Church Road mine and the mineral rights at our Kosse mine.

(4) We transload sand produced at Arland to rail loadouts at New Auburn, Barron, and a third location in Minnesota.

Mineral Reserves

We believe that our strategically located mines and facilities provide us with a large and high-quality mineral reserve base. The coarseness and conductivity of the Northern White frac sand that we mine in Wisconsin significantly enhances recovery of oil and liquids-rich gas by allowing hydrocarbons to flow more freely than would be possible with competing native sand. The low acid-solubility increases the integrity of the Northern White sand relative to other proppants with higher acid-solubility, especially in

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shales where hydrogen sulfide and other acidic chemicals are co-mingled with the targeted hydrocarbons. In addition, its crush resistant properties enable Northern White frac sand to be used in deeper drilling applications than the frac sand produced from mineral deposits located in Texas, Arkansas, or other southern United States locations.

We categorize our reserves as proven recoverable in accordance with SEC definitions and have further limited the definition to apply only to sand reserves that we believe could be extracted at an average cost that is economically feasible. According to such a definition, we estimate that we had a total of approximately 102.4 million tons of proven recoverable mineral reserves as of December 31, 2015. The quantity and nature of the mineral reserves at each of our properties are estimated first by third-party geologists and mining engineers and we internally track the depletion rate on an interim basis. Cooper Engineering Company, Inc. (“Cooper Engineering”) prepared estimates of our proven mineral reserves at our Wisconsin mine locations, while Westward Environmental, Inc. (“Westward”) prepared estimates of our proven mineral reserves at our Kosse facility, each as of December 31, 2015. Our external geologists and engineers update our reserve estimates annually, making necessary adjustments for operations at each location during the year and additions or surveying, drill core analysis and other tests to confirm the quantity and quality of the acquired reserves.

Our mineral reserve leases in Wisconsin with third-party landowners expire at various times between 2036 and 2038. We do not anticipate any issues in renewing these leases should we decide to do so. Consistent with industry practice, we conduct only limited investigations of title to our properties prior to leasing. Title to lands and reserves of the lessors or grantors and the boundaries of our leased properties are not completely verified until we prepare to mine those reserves.

Mines and Wet Plants

The deposits found in our open-pit Wisconsin-based mines are Cambrian quartz sandstone deposits that produce high-quality Northern White frac sand and have a minimum silica content of approximately 99%. Mining takes place in phases lasting from six months to one year in duration, after which the property is reclaimed in a manner that typically provides the landowners with additional cropland.

New Auburn

Our New Auburn wet plant can process up to approximately 2 million tons of wet sand per year. It is located in Chippewa County, Wisconsin, approximately 12 miles from our New Auburn dry plant, to which we have year-round trucking access. The mine site consists of approximately 418 acres adjacent to our New Auburn wet plant. The site contains 15.5 million tons of proven recoverable sand reserves.

In 2011, we awarded Fred Weber, Inc. (“Fred Weber”) a five-year contract for the entirety of our New Auburn mining operations and for a portion of our wet processing needs at that facility. Under this contract, Fred Weber financed and built the wet plant at our New Auburn facility. We amended and extended this contract on January 1, 2015, which now expires in December 31, 2021. Fred Weber now mines the sand reserves, creates stockpiles of washed sand, and maintains the plant and equipment at New Auburn. We agreed, under a take-or-pay arrangement, to purchase 500,000 tons of washed sand from Fred Weber each year that the plant is in operation. We pay Fred Weber a set price per ton of washed sand, subject to adjustments each operational year for diesel prices, the quality of the sand mined, and the quantity of sand purchased. During the term of the agreement Fred Weber will own the wet plant along with the equipment and other temporary structures used for mining on the property. At the end of the term of the agreement or following a default under the contract by Fred Weber, we have the right to take ownership of the wet plant and other mining equipment without charge. Subject to certain conditions, ownership of the plant and equipment will transfer from Fred Weber to us at the expiration of the term. As of December 31, 2015, the contract is suspended until January 1, 2017. During the suspension period, we are responsible for mine upkeep and maintenance.

Thompson Hills

Our Thompson Hills wet plant can process up to approximately 1.6 million tons of wet sand per year. It is located approximately 15 miles from our New Auburn dry plant and 26 miles from our Barron dry plant. The mine site is situated on approximately 580 acres and consists of a series of seven leases in Barron County, Wisconsin. The site contains 38.5 million tons of proven recoverable sand reserves.

We completed construction of the mine and wet plant in September 2014. We incorporated two features into the wet plant that we believe provides the plant with higher quality sand within a more environmentally sound footprint. The first is that we wash our sand both before and after we run the wet sand through the hydrosizer. The resulting sand has turbidity that is the lowest of any wet plant with which we are familiar, which results in less fugitive dust both at our facilities and at the drilling site for our customers. The second is that we separate our fines and other unusable material without the use of settling ponds, which requires that we use less water in our wet plant. Hydraulic mining was implemented at this site during the third quarter of 2015.

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FLS mine

Our FLS wet plant can process up to approximately 1.2 million tons of wet sand per year. It is located approximately 12 miles from our Barron dry plant. The mine site is situated on approximately 364 acres and consists of a series of five adjacent mineral deposits in Barron County, Wisconsin. The site contains 10.2 million tons of proven recoverable sand reserves.

Church Road

Our Church Road wet plant can process up to approximately 1.2 million tons of wet sand per year. It is located less than one mile from our Arland dry plant. The mine site is situated on approximately 130 acres. The site contains 5.3 million tons of proven recoverable sand reserves.

LP Mine

Our LP wet plant can process up to approximately 1.2 million tons of wet sand per year. It is located approximately 2 miles from our Arland dry plant. The mine site is situated on approximately 145 acres. The site contains 5.5 million tons of proven recoverable sand reserves. Hydraulic mining was implemented at this site during the third quarter of 2015.

Kosse

We own the mineral rights to a 225 acre mineral deposit located in Kosse, Texas, adjacent to our Kosse dry plant. The deposit has a minimum silica content of approximately 99% and controlling attributes that include sand grain crush strength and size distribution. As of December 31, 2015, the Kosse mineral deposit contained approximately 27.4 million tons of proven recoverable reserves and 5.4 million tons of probable recoverable reserves, which we process into a high-quality, 100 mesh frac sand. The wet plant at our Kosse facility is capable of producing up to 1.6 million tons of wet sand per year. We are not obligated to make royalty payments in connection with our mining operations at this location. We use heavy equipment to mine sand from the open-pit. We plan to introduce hydraulic mining techniques to our Kosse mine in 2016.

Future Projects

In December 2015, we gained access to a significant reserve base in Jackson County, Wisconsin through a business arrangement with a contracted customer, Performance Technologies, L.L.C. ("PTL"). Our internally-prepared geological analysis indicates that the reserve rights total approximately 94 million tons of high quality Northern White frac sand. These reserves cannot yet be classified as proven and probable reserves as of December 31, 2015. The assets acquired include certain owned and leased land, sand deposit leases and related prepaid royalties, and transferable mining and reclamation permits. This transaction not only provides us with an increase to high quality sand reserves but also strengthens our position in the marketplace with a leading pressure pumper across a number of shale plays in North America. In consideration for the assets, PTL and SSS amended and restated the existing supply agreement between the parties and entered into a new sand purchase option agreement that provide PTL with a market-based discount on sand purchased from SSS. Under the new agreements with PTL, SSS has the option to supply the contracted tons from its existing footprint of northern white sand operations or construct a new sand mine and dry plant in Jackson County, Wisconsin. Given the current challenging market conditions for proppant demand, we have deferred the construction of the new facility until the North American oil and gas markets improve.

Dry Plant Facilities

Arland

Our Arland dry plant is located in the township of Arland in Barron County, Wisconsin on approximately 22 acres that we own. The facility is located on a county road, which gives us year-round trucking access, and is situated approximately 11 miles from our Barron facility, and 37 miles from our New Auburn facility. Our Arland dry plant is an enclosed facility that has a rated production capacity of 8,800 tons per day year-round and regardless of weather conditions. Our current air permit allows us to produce up to 2.5 million tons per year of finished product. The facility has a 300 ton per hour natural gas fired rotary dryer as well as twelve high capacity gyratory mineral separators, or "screeners." Our finished product is transported via truck to one of our dry plant facilities with rail access, or to a third-party rail loadout facility located in Minnesota.

For the year ended December 31, 2015, our Arland facility produced approximately 1.1 million tons of Northern White frac sand. In January 2016, we temporarily idled the Arland plant due to the challenging market conditions and higher cost structure as compared to our other proximate dry plants.

Barron

Our Barron dry plant is located in the township of Clinton, Wisconsin in Barron County on 83 acres that we own. The facility is located on a US Highway, which gives us year-round trucking access, and is situated along a rail spur owned by the Canadian National ("CN") railway that connects to the CN main line. Our Barron dry plant is an enclosed facility that has a rated production capacity of 8,800 tons per day year-round regardless of weather conditions, and has on-site railcar loading facilities. Our current air permit allows us to produce up to 2.4 million tons per year of finished product. The facility has a 300 ton per hour natural gas fired rotary dryer as well as twelve high capacity screeners. Our railyard at Barron consists of 18 spur tracks and is capable of storing up to 650 railcars.

Our location on the CN rail spur allows us to offer direct access to the rapidly growing oil and gas shale plays in northwestern Canada and the northeastern United States, including the Western Canadian Sedimentary Basin, the Marcellus Shale, and the Utica Shale plays. The CN also presents us with access to emerging plays in the southern United States as well as the port of New Orleans, which provides us access to emerging oil and gas markets in Latin America.

The Barron facility houses our technology-driven proppant (SandGuard™ and SandMaxx™) production circuits. In late 2015, we installed equipment that applies coating material for our SandGuard™ product. Our SSP pilot plant upgrade is currently under construction and will provide production of SandMaxx™ in limited quantities until the technology is tested in the field. If the technology proves successful and widely demanded by our customers, we will evaluate a larger-scale upgrade to an existing facility.

For the year ended December 31, 2015, our Barron facility produced approximately 1.5 million tons of Northern White sand.

New Auburn

Our New Auburn dry plant is located in Barron County, Wisconsin, approximately 12 miles from our New Auburn mine. The facility is on 37 acres that we own in the village of New Auburn, Wisconsin along a short line that connects with the mainline of the Union Pacific (“UP”) railway. Our New Auburn dry plant is an enclosed facility that has a rated production capacity of 4,400 tons per day year-round regardless of weather conditions, and has on-site railcar loading facilities capable of loading railcars. Our current air permit allows us to produce up to 1.4 million tons per year of finished product. The facility has a 175 ton per hour natural gas fired fluid bed dryer as well as six screeners.

We have access to a segment of on-site rail track that is tied into a rail line owned by UP, and we use this rail space to stage and store empty or recently loaded customer railcars. Because of the cost efficiencies of shipping frac sand by rail, our location adjacent to a UP short line provides our customers with the ability to transport Northern White frac sand from our New Auburn facility to major oil and natural gas basins currently producing in the United States and western Canada, including access to high-activity areas of oil production in Texas, Oklahoma, Colorado and the western United States.

For the year ended December 31, 2015, our New Auburn facility produced approximately 0.6 million tons of Northern White sand.

Kosse

Our Kosse dry plant is located adjacent to our Kosse mine and wet plant on land we own in Kosse, Texas. The facility has a rated production capacity of 1,650 tons per day year-round. The dry plant utilizes a 200 ton per hour natural gas fired rotary dryer that is capable of producing up to 600,000 tons per year of dry native Texas frac sand, and has an air permit that allows us to produce up to 1.2 million tons per year of finished product. We introduced new processing techniques at our Kosse plant in 2015 that allowed us to inexpensively extract significant amounts of saleable frac sand from previously mined and discarded waste sand. The plant produces 100-mesh native Texas sand and is capable of producing a higher-cut 40/70 frac sand. We also sell sand to non-energy end users, including industrial applications, and sports sand for golf courses, stadiums and other sports-related venues. The Kosse facility has three on-site 1,000-ton storage silos designed for loading trucks for delivery to local and regional markets.

For the year ended December 31, 2015, our Kosse facility produced approximately 277,000 tons of frac sand.

Transportation Logistics and Infrastructure

We sell our sand both free-on-board (“FOB”) at our plants as well as at transload facilities that are closer to the wellhead. As the frac sand market has evolved, the point of sale between producers and purchasers of frac sand continues to move away from the FOB plant model and closer to the wellhead. For the year ended December 31, 2015, we sold approximately 58% of our sand FOB plant and 42% FOB transload and/or FOB wellhead. At our Kosse, Texas plant, orders are picked up by truck because most orders are transported 200 miles or less from our plant site. Because nearly all product from our Wisconsin plants is transported in excess of 200 miles and transportation costs typically represent more than 50% of our customers' overall cost for delivered Northern White sand, the majority of our Wisconsin shipments are transported by rail to a transload and storage location in close proximity to the customer's intended end use destination.

While many of our customers continue to purchase FOB plant, we offer our customers a total supply chain solution pursuant to which we manage every aspect of the supply chain from mining and manufacturing to delivery within close proximity to the wellhead. Currently, we have built a fleet of company-leased and customer-committed railcars, assembled a network of leased transload and terminal storage sites located near major shale plays, and designed a supply chain management system all of which allow us to flexibly and efficiently coordinate rail, truck, and storage assets with customer order information.

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Transload Facilities

Due to limited storage capacity at or near the wellhead, our customers generally find it impractical to store frac sand in large quantities immediately near their job sites. We can service manifest rail deliveries or unit train shipments and minimize product fulfillment lead times through the simultaneous handling of multiple customers' railcars. In order to continue to service the customer closer to the wellhead, we have assembled a network of transload facilities within a number of the major basins that we serve. Below is a summary of the transload sites that we operate out of as of December 31, 2015.

Transload Location by Basin	Transload Sites as of December 31, 2015	Transload Sites Capable of Receiving Unit Trains	2015 Volume Sold (Thousands of Tons)
Bakken Shale	2	1	176
Barnett Shale	1	—	9
Eagle Bine Shale	1	—	6
Eagle Ford Shale	1	1	240
Haynesville Shale	1	1	67
Marcellus / Utica Shales	4	—	307
Mid-Continent Basin	1	1	160
Permian Basin	2	—	153
Western Canadian Sedimentary Basin	2	2	307
Total	15	6	1,425

As the frac sand industry has evolved, so have the railcars that serve the industry, which means that we seek to have our fleet comprised, as much as possible, of dedicated 286,000 pound railcars designed specifically for loading and unloading of frac sand. As of December 31, 2015, we had a total of 5,657 railcars in our fleet, including 326 railcars that are owned or leased by our customers but dedicated to us, and 5,331 railcars that we lease with a weighted average remaining term of 4.7 years. We anticipate that we will be able to renew these leases at favorable terms when they expire. We also ordered an additional 2,855 railcars for lease, 2,355 of which have been or are expected to be delivered during 2016. Given the reduction in frac sand sales volume, we have initiated discussions with some of our railcar lessors to grant us relief on our fixed operating lease obligations.

Permits

In order to conduct our sand operations, we are required to obtain permits from various local, state and federal government agencies. The various permits we must obtain address such issues as mining, construction, air quality, water discharge, noise, dust, and reclamation. Prior to receiving these permits, we must comply with the regulatory requirements imposed by the issuing governmental authority. In some cases, we also must have certain plans pre-approved, such as site reclamation plans, prior to obtaining the required permits. A decision by a governmental agency to deny or delay issuing a new or renewed permit or approval, or to revoke or substantially modify an existing permit or approval, could have a material adverse effect on our ability to continue operations at the affected facility. Expansion of our existing operations also is predicated upon securing the necessary environmental and other permits and approvals. We have obtained all permits required for the operation of our existing facilities. We will also obtain permits necessary to process and distribute any new product, as might be required.

Intellectual Property

Our intellectual property consists primarily of patents, trade secrets, know-how and products such as “SandMaxx™” and “SandGuard™.” We hold 11 U.S. granted patents that are still in force, the majority of which have an expiration date after 2027. Typically, we utilize trade secrets to protect the formulations and processes we use to manufacture our products and to safeguard our proprietary formulations and methods. We believe we can effectively protect our trade secrets indefinitely through the use of confidentiality agreements and other security measures.

Fuel Segment

The Fuel segment consists of our facilities located in the Dallas-Fort Worth metropolitan area and in Birmingham, Alabama, which are operated by Direct Fuels and AEC, respectively. Through this segment, we acquire and process transmix, which is a blend of different refined petroleum products that have become co-mingled in the pipeline transportation process; sell wholesale petroleum products; provide third-party terminaling services; and provide other complementary products and services. In these two markets, we are able to offer our customers gasoline and diesel at market rates, 24 hours a day, seven days a week. A selected summary of our fuel capacity and volumes for the year ended December 31, 2015 follows:

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Plant Location	Transmix Processing Capacity	Fuel From Transmix Sold	Wholesale Fuel Volume Sold	Terminal Tankage Capacity	Terminal Throughput Volume
	(Volumes in thousands of gallons)				
Dallas-Fort Worth, TX	107,310	53,271	22,438	11,990	49,208
Birmingham, AL	76,650	39,858	124,566	21,979	73,971

In our transmix business, we acquire transmix from terminal operators and others, which is delivered by pipeline or truck to our facilities. We then process the transmix into refined products such as conventional gasoline and low sulfur diesel, which we sell over our truck loading rack to third party distributors as well as off-road customers such as railroad, and marine operators. We structure our transmix purchase agreements to capture a stable margin, as the price differential between the indices at which we purchase transmix supply and the sales price of the corresponding refined product. While our transmix purchase agreements are designed to capture a stable margin at the time of purchase, the final sales price is subject to daily fluctuations in fuel prices, and this holding period risk affects our profitability. We seek to partially mitigate the holding period risk by hedging a portion of our inventories.

In our wholesale fuel business, we purchase fuel that is delivered to our tanks via pipeline, which we then subsequently sell over our truck loading rack. At our Birmingham facility, we receive refined fuels on pipelines operated by Plantation Pipeline, and Colonial Pipeline. We have shipper status on the Plantation line, but our space allocation is currently limited to one cycle per month. Over time, we expect an increase in the Plantation space allocation as our shipping history expands. Colonial currently allocates pipeline space via a lottery system, and we participate in their monthly lottery. At our Dallas-Fort Worth facility, we receive refined fuels and transmix on two lines operated by Explorer Pipeline Company, and we are connected to an independent refiner via a private pipeline. Our average holding period for transmix and wholesale gallons is 7-10 days, which serves to minimize, but not eliminate, the effects of daily fluctuations in fuel price.

In our terminaling business, we lease our terminal space to third parties who use our facilities to store refined petroleum products. We are able to charge customers for the storage, intake, and/or outtake of refined products. We also have injection additive systems that allow us to sell branded gasoline, which we believe will increase our terminal customers and revenue base over time.

Other services include blending of renewable fuels into petroleum products, the manufacture of biodiesel at our Birmingham facility and certain reclamation services, which consist primarily of tank cleaning services. We also are a net producer of Renewable Identification Numbers, or RINs, which we sell to reduce our cost of goods sold.

There are three components of margin contribution as it relates to the distribution of gasoline and diesel fuel, both purchased fuel and that refined from transmix. The base margin is the difference between our selling price of the refined product and our purchase price for refined fuel and transmix, plus any processing costs. The second component is the holding cost, the price volatility between the time we purchase the fuel and the time it is sold. Typically, this holding period ranges from seven to ten days. Gains or losses from the hedging program are considered in determining the holding cost component. The third component is the cost of bringing off-specification fuel from transmix processing up to acceptable standards and the benefit of RINs generated from the blending of renewable fuels.

In our transmix business, we produce both low sulfur diesel and ultra-low sulfur diesel, depending on the sulfur content of the incoming stream of transmix. Low sulfur diesel contains no more than 500 parts per million, or ppm, of sulfur, and it is currently used primarily for marine applications. Ultra-low sulfur diesel, which began replacing low sulfur diesel in 2006 for on-highway applications, contains no more than 15 ppm of sulfur. Ultra-low sulfur diesel meets Environment Protection Agency, or EPA standards for on-highway diesel fuel sold at retail locations in the United States and can also be used in all on-road and off-road applications.

In 2012, the EPA issued a rule that allowed the use of low sulfur diesel produced by transmix processors in locomotive engines as long as there is a market for it. In a separate rule, the EPA required major railroad operators, beginning in 2015, to purchase locomotives with engines fueled exclusively by ultra-low sulfur diesel, meaning that they cannot accept low sulfur diesel. Railroads are permitted to continue utilizing earlier generation locomotives (Tier 3 engines), but over time, their fleets will transition to equipment that uses ultra-low sulfur diesel (Tier 4 engines). As a result, the low sulfur diesel that our Fuel segment historically sold from our transmix processing will be phased out of the locomotive market, beginning in the middle of 2015. During the second quarter of 2015, we adopted business practices to accommodate the shift in product mix from our railroad customers. The shift to other uses is generally less profitable, including sales to marine operators, small railroads, and refiners. To permanently address the product shift from low sulfur diesel to ultra-low sulfur diesel, we are currently constructing hydrotreaters at our facilities located in Birmingham and Dallas-Fort Worth, which are designed to remove excess sulfur during the distillation and refining process. The hydrotreater at the Dallas-Fort Worth facility is expected to be operational in April 2016, while the hydrotreater at the Birmingham facility is expected to be operational in July 2016. When both hydrotreater projects become operational, our transmix-derived diesel will qualify for on-road use as ultra-low sulfur diesel. When operational, we believe the hydrotreaters

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will increase our per-gallon base margin as well as source additional supplies of transmix and off-specification fuel that tends to be at a lower cost because of the higher sulfur content. For both hydrotreater projects, we expect to invest approximately $17 million, of which we had already paid $6.7 million as of December 31, 2015.

We believe there are other attractive opportunities to continue to grow our transmix, wholesale, terminaling, and other operations. We are seeking to enter into contracts for additional transmix supplies, which we could process using existing excess capacity. While our Dallas-Fort Worth facility ran its transmix tower at approximately 50% of capacity, our Birmingham transmix tower, which is one of the newest transmix towers in the United States, was running at approximately one-half of its design capacity at the end of 2015. We also continue to seek additional terminaling customers, and regularly analyze our wholesale customers to maximize profitability.

As part of a broader business strategy, we are actively engaged in efforts to sell the Fuel segment. While we remain active in these efforts to identify a potential buyer, we have not entered into an agreement to sell the Fuel segment.

Dallas-Fort Worth Facility

At our Dallas-Fort Worth facility, we offer our customers a diverse, high-quality product mix, including conventional gasoline and low sulfur diesel from our transmix processing and ultra-low diesel from both our transmix processing and bulk purchases. This facility is strategically located in the metropolitan area on approximately 20 acres that we own and provides access to an attractive market for our fuel products, and direct connections to third-party refined products pipelines that service our transmix processing units and adjacent storage tanks. Specifically, we can receive transmix and bulk fuel product via three different pipelines at or near this facility, including the 28-inch and 10-inch pipelines owned by Explorer Pipeline Company, and a third connection to a major independent refiner's proprietary products pipeline. The 10-inch Explorer and the independent refiner pipelines terminate within a mile of our facility. Additionally, we can receive inbound products including transmix via truck.

At this facility, we own two transmix processing units, and these two units have a combined processing capacity of approximately 7,000 barrels of transmix per day. We sold, on average, 3,475 barrels per day of refined products processed from transmix during the year ended December 31, 2015.

On average, we purchase 49,000 barrels of ultra-low diesel each month under short-term purchase contracts. In addition, we receive throughput fees from one customer who stores its own refined fuel products at our terminal.

Also at this facility, we have 49 storage tanks with a total storage capacity of approximately 250,000 barrels. Additionally, we lease approximately 25,000 barrels of bulk fuel storage at a third party terminal that is connected to us by pipeline. While we continually strive to minimize inventory, our significant storage capacity provides us with the ability to receive large inbound batches of transmix from our transmix suppliers, and also allows us to offer our customers a wide range of fuel products.

We are able to distribute our fuel products efficiently through a truck rack that is connected to our storage tanks. Our two-lane truck rack has a maximum daily capacity of 144 full-sized tank-trucks with an average utilization of 84 trucks per day. In addition, our truck rack is fully automated so truck drivers can quickly and easily select the specific blend of fuel that meets their needs.

Birmingham Facility

At our Birmingham facility, we also offer our customers a diverse, high-quality product mix, including conventional gasoline and low sulfur diesel from our transmix processing as well as gasoline and ultra-low diesel in connection with our wholesale fuel distribution operations. In addition, we provide a suite of complementary fuel products and services, including third-party terminaling, renewable fuel blending, and reclamation services.

This facility is strategically located on approximately 40 acres that we own and provides us access to an attractive market for our fuel products, and two direct connections to third-party product pipelines directly serving our transmix processing units and adjacent storage tanks. Specifically, we can receive transmix and refined fuels via pipeline spurs from pipelines operated by Colonial Pipeline and Plantation Pipeline. Additionally, we can receive inbound products and transmix via truck.

At this facility, we own one transmix processing unit that has a processing capacity of approximately 5,000 barrels of transmix per day. We sold, on average, approximately 2,600 barrels per day of refined products processed from transmix during the year ended December 31, 2015.

Also at this facility, we have 44 storage tanks with total storage capacity of approximately 523,000 barrels, which is one of the largest volumes of storage capacity of any market participant in Birmingham, Alabama. While we continually strive to minimize inventory, our significant storage capacity provides us with the ability to receive large inbound batches of transmix from our transmix suppliers and wholesale bulk purchases, which allows us to offer our customers a wide range of fuel products in connection with our wholesale fuel distribution operations.

We are able to distribute our fuel products efficiently through a truck rack that is connected to our storage tanks. Our four-lane truck rack has a maximum daily capacity of 384 full-sized tank-trucks with an average utilization of approximately 100 trucks per

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day. In addition to gasoline and diesel, we also offer our customers biodiesel, ethanol, and other additive blending at the rack. The truck rack is fully automated so that truck drivers can quickly and easily select the specific blend of fuel that meets their needs. Pursuant to month-to-month contracts with several of our customers, we also receive tolling fees on their gasoline and diesel that are sold across our truck rack.

We also manufacture biodiesel at this facility. Biodiesel contains no petroleum products and can be blended with petroleum-based diesel to create a biodiesel blend. Biodiesel is a clean-burning fuel that produces lower greenhouse gas emissions than petroleum diesel when each is separately combusted. Large refining companies are required to blend biodiesel with a portion of their ultra-low sulfur diesel, or to purchase and retire a comparable volume of RINs. It is generally more economical to purchase and blend biodiesel than to purchase and retire RINs. This refinery has a practical capacity of producing approximately two million gallons of biodiesel fuel annually, and produced 0.9 million gallons during the year ended December 31, 2015.

We also operate equipment that allows us to offer customers a unique alternative for the disposal of refined petroleum tank bottoms and petroleum contact water, or PCW. By reclaiming fuels from these waste streams and placing them back into fuel service, our reclamation services eliminate the need for hazardous waste disposal. We also have approximately 17 petroleum tank trailers and 13 vacuum trucks, which enable us to assist in tank cleanings and PCW transportation that range in size and scope.

Corporate

Certain items are reviewed by our management on a consolidated basis, and are therefore presented as corporate operations rather than segment operations:

- general and administrative costs related to corporate overhead, such as headquarters facilities and personnel, as well as equity-based compensation;
- certain other operating costs such as IPO transaction-related; and
- non-operating items such as interest, other income and income taxes.

Customers

Sand

We sell substantially all of our sand to customers in the oil and gas proppants market. Our customers include major oilfield services companies that are engaged in hydraulic fracturing. Sales to the oil and gas proppants market comprised approximately 99% of our total Sand segment sales in 2015.

In 2015, total sales to customers currently under long-term contracts, including take-or-pay, fixed-volume, and efforts-based contracts, accounted for 83% of our total Sand segment sales. As of December 31, 2015, we have 7.5 million tons under long-term contract with a weighted average remaining term of four years. In 2015, we recognized $11.1 million of shortfall revenues on take-or-pay customer contracts. Due to current market conditions and recent revisions to certain take-or-pay contracts, we do not expect to recognize income in 2016 associated with take-or-pay shortfalls.

While we continue to actively pursue take-or-pay and fixed-volume contracts as part of our broader strategy, our customers increasingly favor efforts-based contracts over take-or-pay or fixed-volume contracts. As part of the overall value proposition, we also believe customers will be focused on the relative quality of sand, logistics capabilities, and service level offered by their frac sand providers.

Fuel

Our primary fuel processing and distribution markets are the Dallas-Fort Worth metropolitan area and Birmingham, Alabama. According to recent census estimates, these markets combined to include approximately 8 million people. We are a key seller to unbranded retailers and petroleum wholesalers, and act as a key supplier of terminaling services to various fuel refiners and large fuel marketing companies. The unbranded gasoline market has seen high growth in recent years due to a decline in the willingness of consumers to pay a premium for branded fuel. Many unbranded retailers have difficulty purchasing from the major distributors due to the restrictive supply relationship between such distributors and their franchised retailers. As unbranded retailers have expanded in recent years, we have acted as a key supplier to this market. We have capitalized on supplying the unbranded gasoline market because only limited quantities of unbranded fuel are stored in the regions in which we operate.

We also have terminaling contracts with major marketers of branded gasoline at our Dallas-Fort Worth and Birmingham facilities. These contracts were made possible because of the branded fuel additive systems that we installed at each facility.

Suppliers and Service Providers

Sand

We believe frac sand companies differentiate themselves from a cost and service perspective, based on their ability to wash, screen, dry, and ship product efficiently. Mineral extraction is also an important component of frac sand operations, but this aspect of production is valued less because it can be performed efficiently by specialized third party providers. For mineral extraction at our mine sites in Wisconsin and Texas, we engaged experienced mining contractors to manage our excavation activities.

We have engaged Fred Weber to mine and process wet sand at our New Auburn wet plant facility under a contract that expires at the end of 2021, at which time title and operations of the facility will revert to us. Fred Weber has mined and processed wet sand at New Auburn since we commenced operations in 2011. As of December 31, 2015, the Weber contract has been suspended until January 1, 2017. In July 2014, we closed on the acquisition of Midwest, which had been a supplier to us prior to the acquisition. During 2014, we purchased wet sand from other third parties in order to ensure sufficient wet sand for our dry plant operations. We did not purchase any third party wet sand outright in the fiscal year ended December 31, 2015. Because of significant investment in new mines and wet sand facilities in 2014, we do not believe we will need to purchase any material wet sand from third parties in 2016.

Fuel

We purchase transmix from pipeline or terminal operators, primarily under contractual arrangements that benefit us and our suppliers. Generally, we structure our supply contracts so that we receive all of our suppliers' transmix volume, regardless of regulatory changes, expansions of operations, higher utilization rates or other factors that may increase their supply. This helps assure our suppliers that their transmix will be removed on a timely basis so that their operations will not be interrupted. Major refineries prefer not to process transmix because it is less economical than processing crude oil due to the relatively lower volumes, decreased efficiency and concerns associated with the impact that fuel additives may have on expensive catalysts. We enable refiners to remain focused on crude oil processing by providing an economical and reliable solution for their transmix processing.

We currently purchase approximately 59% of our supply of transmix pursuant to contracts with terms ranging from 12 to 48 months, with a volume-weighted average remaining duration of 11.75 months as of December 31, 2015. The remainder of our supply of transmix is purchased on a spot basis. For the year ended December 31, 2015, our three largest suppliers of transmix accounted for approximately 17%, 13% and 8% of our total transmix purchases. The contract with our largest supplier expires on September 30, 2017.

We receive transmix by truck and pipeline, depending upon the geographic location of each of our supply points. In general, truck shipments are more expensive but they allow us to receive small batches on a frequent basis. As a result, truck receipts are generally lower margin than pipeline receipts but inventory requirements are minimal. Conversely, pipeline shipments generally have to be aggregated to make shipments that meet minimum batch sizes for pipeline companies but the transportation cost is lower than for truck shipments.

Our wholesale fuel suppliers include major oil companies that ship us wholesale fuel via scheduled pipeline tenders or through in-tank transfers at our Birmingham facility.

Competition

Sand

The frac sand market is a highly competitive market that is comprised of a small number of large, national producers, which we also refer to as “Tier 1” producers, and a larger number of small, regional, or local producers. Competition in the frac sand industry has increased in recent years due to favorable pricing and demand trends, and we expect competition to continue to increase. Suppliers compete based on price, consistency, and quality of product, site location, distribution capability, customer service, reliability of supply, breadth of product offering and technical support.

Based on management's internal estimates, we believe we were one of the five largest producer of frac sand in 2015 by production capacity and quality, together with FMSA Holdings, Inc., Hi-Crush Proppants LLC, U.S. Silica Holdings, Inc., and Unimin Corporation. In recent years there has also been an increase in the number of small producers servicing the frac sand market due to increased demand for hydraulic fracturing services and related proppant supplies. Demand trends up until the end of 2014 attracted new frac sand supply which has softened pricing for most products in light of recent demand trends in the North American oil and natural gas industry. We believe, however, that the relative inexperience of many management teams operating in the frac sand industry coupled with the costs, length of time and operational challenges associated with identifying attractive frac sand reserves, obtaining necessary permits and regulatory approvals and constructing a sand processing facility will prevent these smaller competitors from prospering in the long-run. Further, the large capital outlay required to develop a national logistics network is a barrier to entry in a regular market environment. We believe that industry consolidation and the exit from the market

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by less successful competitors will occur in the near-term and should benefit the pricing environment for SSS and the remaining frac sand producers.

Fuel

We are the only transmix processor operating in the Dallas-Fort Worth and Birmingham markets. In general, transmix shipped by truck is less competitive than transmix shipped by pipeline, and these logistical considerations typically lead a transmix supplier to the conclusion that there is only one appropriate location for processing its transmix in a geographic region. In cases where transmix can be transported economically by pipeline to several different transmix processing locations, the level of competition is significantly greater. In addition to price, suppliers of transmix also consider storage capacity, which minimizes the risk that transmix will not be removed on a timely basis, financial strength, and operational history when evaluating potential transmix processors.

We compete with other wholesale distributors of refined products in our markets. Our competitors include large, integrated, major, or independent oil companies operating in our markets. Because these competitors have more diverse operations and stronger capitalization, they may be better positioned than we are to withstand changing industry conditions, including shortages or excesses of petroleum products, or intense price competition at the wholesale level.

Fuel terminal customers make their purchasing decisions based on several criteria. The most important criteria are price, location, service, and product breadth/consistency. The price of fuel is generally a customer's primary focus, but that price must also take into account the cost of transportation. Terminals closer to sub-markets that are the largest consumers of fuel have an economic advantage over more remote terminals. Our Dallas-Fort Worth terminal is centrally located so we can economically serve most major sub-markets in Dallas-Fort Worth. Our Birmingham terminal is located in the same area as all other major fuel terminals in the market. The most important elements in providing quality service to terminal customers are speed of throughput, and efficient back-office operations. Customers rarely have to wait to load at our truck racks, given our significant excess rack capacity. We also believe we have a system that provides us with a high degree of accuracy when billing our customers. Additionally, a broad product offering is important because customers generally prefer to be able to obtain multiple types of fuel from one supplier. Finally, our customers prefer suppliers who are capable of providing product every day. The addition of wholesale product to supplement the products resulting from our own transmix processing operations provides us with a broad product line for our core customers, and makes it more likely that we will have product available for sale every day.

Seasonality

At our Sand segment, it is challenging to process raw sand during sub-zero temperatures, therefore, frac sand is typically water-washed only eight months of the year at our Wisconsin operations. This results in a seasonal build-up of inventory as we excavate excess sand to build a stockpile to feed the dry plant during the winter months, causing the average inventory balance to increase from a few weeks in early spring to more than 100 days in early winter. These seasonal variations in inventory balance affect our cash flow. We may also sell frac sand for use in oil and gas basins where severe winter weather conditions may curtail drilling activities and, as a result, our sales volumes to those areas may be adversely affected. For example, we could experience a decline in both volumes sold and segment income for the second quarter relative to the first quarter each year due to seasonality of frac sand sales into western Canada because sales volumes are generally lower during April and May due to limited drilling activity resulting from that region's annual thaw.

Our Fuel operations have not historically reflected any material seasonality. However, as we do hold refined petroleum products in our terminals and may take title to the product as it is shipped to our terminals, we expect to experience marginally higher earnings in periods where refined product prices are rising, and marginally lower earnings in periods where refined product prices are falling.

Insurance

We believe that our insurance coverage is customary for the industries in which we operate and adequate for our business. We periodically review insurance plans to address most, but not all, of the risks against our business. Losses and liabilities not covered by insurance would increase our costs. To address the hazards inherent in our business, we maintain insurance coverage that includes physical damage coverage, third-party general liability insurance, employer's liability, environmental and pollution and other coverage, although coverage for environmental and pollution-related losses is subject to significant limitations.

Environmental and Occupational Health and Safety Regulations

We are subject to stringent and complex federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to protection of worker health, safety and the environment. These regulations include compliance obligations for air emissions, water quality, wastewater discharges and solid and hazardous waste disposal, as well as regulations designed for the protection of worker health and safety and threatened or endangered species. Compliance with these environmental laws and regulations may expose us to significant costs and liabilities and cause us to incur significant capital expenditures in our

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operations. We are often obligated to obtain permits or approvals in our operations from various federal, state and local authorities. These permits and approvals can be denied or delayed, which may cause us to lose potential and current customers, interrupt our operations and limit our growth and revenue. Moreover, failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of remedial obligations, and the issuance of injunctions delaying or prohibiting operations. Private parties may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. While we believe that our operations are in substantial compliance with applicable environmental laws and regulations and that continued compliance with current requirements would not have a material adverse effect on us, there is no assurance that this degree of compliance will continue in the future. In addition, the clear trend in environmental regulation is to place more restrictions on activities that may affect the environment, and thus, any changes in, or more stringent enforcement of, these laws and regulations that result in more stringent and costly pollution control equipment, waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on our operations and financial position.

We do not believe that compliance with federal, state or local environmental laws and regulations will have a material adverse effect on our business, financial position or results of operations or cash flows. We cannot assure you, however, that future events, such as changes in existing laws or enforcement policies, the promulgation of new laws or regulations or the development or discovery of new facts or conditions adverse to our operations will not cause us to incur significant costs. The following is a discussion of material environmental and worker health and safety laws that relate to our operations.

Air emissions. Our operations are subject to the Clean Air Act, as amended (the "CAA"), and comparable state and local laws, restrict the emission of air pollutants from many sources and also impose various monitoring and reporting requirements. Compliance with these laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air emissions permit requirements or utilize specific equipment or technologies to control emissions. Obtaining air emissions permits has the potential to delay the development or continued performance of our operations. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or to address other air emissions-related issues such as, by way of example, the capture of increased amounts of fine sands matter emitted from produced sands. Moreover, facilities that emit volatile organic compounds or nitrogen oxides face increasingly stringent regulations, including requirements to install various levels of control technology on sources of pollutants. In addition, the petroleum processing sector is subject to stringent and evolving EPA and state regulations that establish standards to reduce emissions of certain listed hazardous air pollutants. While the hazardous air pollutant emissions from our facilities are below the threshold levels for the stringent maximum achievable control technology, or MACT, standards to apply, our Dallas-Fort Worth facility is an "area source" subject to the less stringent generally achievable control technology standards for gasoline distribution terminals that were promulgated by EPA in January 2011. In addition, air permits are required for our processing and terminal operations, and our frac sand mining operations that result in the emission of regulated air contaminants. These permits incorporate the various control technology requirements that apply to our operations and are subject to extensive review and periodic renewal. Any future changes to existing requirements, non-compliance, or failure to maintain necessary permits or other authorizations could require us to incur substantial costs or suspend or terminate our operations.

The CAA also requires states to draft State Implementation Plans ("SIPs") designed to attain national health-based ambient air quality standards ("NAAQS") in primarily major metropolitan and/or industrial areas. SIPs frequently regulate emissions from stationary sources such as our operations. The Dallas-Fort Worth area is currently in nonattainment with the ozone NAAQS. New regulations designed to bring the Dallas-Fort Worth area into attainment with the ozone NAAQS were adopted by the Texas Commission on Environmental Quality (the "TCEQ") in late 2011. We believe, based upon the adopted regulations, that no material capital expenditures beyond those currently contemplated and no material increase in costs are likely to be required. In October 2015, the EPA finalized a more stringent ozone NAAQS, which could ultimately result in the adoption of more stringent regulations by the TCEQ.

The CAA authorizes the EPA to require modifications in the formulation of the refined transportation fuel products we manufacture in order to limit the emissions associated with the fuel product's final use. For example, in December 1999, the EPA promulgated regulations limiting the sulfur content allowed in gasoline. These regulations required the phase-in of gasoline sulfur standards beginning in 2004, with special provisions for small refiners and for refiners serving those Western states exhibiting lesser air quality problems and, more recently, the EPA finalized on March 3, 2014, rules to further reduce the sulfur content of gasoline beginning in 2017. Similarly, the EPA promulgated regulations that limited the sulfur content of on-road diesel fuel beginning in 2006 from its current level of no more than 500 ppm to no more than 15 ppm. A portion of our transmix consists of jet fuel, which currently is not subject to the EPA regulations that limit the sulfur content of most categories of motor fuels. However, the sulfur content of various types of diesel fuel is subject to a decreasing series of sulfur concentration limits, for example a 15 ppm maximum sulfur concentration in all categories of diesel fuel except for locomotive and marine diesel that is sold after May 31, 2014. If the transmix we receive after May 2014 contains sufficient quantities of jet fuel, the sulfur content of the diesel fuel we produce from our transmix may exceed the 15 ppm level and, if it does, we will be prohibited from marketing this fuel for any uses other than locomotive or marine, or for any use within the Northeast and Mid-Atlantic regions of the United States. Further, as EPA emissions standards for locomotives grow more stringent through 2020, certain locomotives will be required to move to lower sulfur diesel, limiting sales of diesel with sulfur above 15 ppm to certain old locomotives and marine sources only.

On August 16, 2012, the EPA published final rules that establish new air emission controls and practices for oil and natural gas production wells, including wells that are the subject of hydraulic fracturing operations and natural gas processing operations. These rules will require, among other things, the reduction of volatile organic compounds from certain natural gas wells through the use of reduced emission completions or “green completions” in all hydraulically fractured or re-fractured wells after January 1, 2015. For subject well completion operations occurring at such well sites before January 1, 2015, the final regulations will allow operators to capture and direct flowback emissions to completion combustion devices, such as flares in lieu of performing green completions. These regulations also establish specific new requirements regarding emissions from dehydrators, storage tanks and other production equipment. The EPA later updated the storage tank standards on August 5, 2013 to phase in emission controls more gradually. In August 2015, the EPA proposed additional regulations to control emissions of methane and volatile organic compounds from the oil and natural gas sector. Compliance with these rules could result in significant costs to our customers, which may have an indirect adverse impact on our business.

The CAA also requires an increasing percentage of vehicle fuels to come from renewable sources, including biodiesel. The regulations implementing this “Renewable Fuel Standard” or RFS, may be adjusted by the EPA administrator, or reduced or eliminated as a result of litigation challenging the RFS, if sufficient quantities of renewable fuels are not available. Uncertainty surrounding the potential for the EPA or a court to lower the standards for biodiesel or other renewable fuels could affect our business.

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

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

Independent of Congress, the EPA is beginning to adopt regulations controlling GHG emissions under its existing authority under the CAA. For example, in 2009, the EPA adopted rules regarding regulation of GHG emissions from motor vehicles. In addition, on September 22, 2009, the EPA issued a final rule requiring the reporting of GHG emissions in the United States beginning in 2011 for emissions occurring in 2010 from specified large GHG emission sources. On November 30, 2010, the EPA published a final rule expanding its existing GHG emissions reporting rule for certain petroleum and natural gas facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year, which was again amended in October 2015 to cover additional oil and natural gas operations. In 2010, the EPA also issued a final rule, known as the “Tailoring Rule,” that makes certain large stationary sources and modification projects subject to permitting requirements for GHG emissions under the CAA.

Although it is not currently possible to predict how any such proposed or future GHG legislation or regulation by Congress, the EPA, the states or multi-state regions will impact our business, any legislation or regulation of GHG emissions that may be imposed in areas in which we conduct business could result in increased compliance costs or additional operating restrictions or reduced demand for our services, and could have a material adverse effect on our business, financial condition and results of operations.

Further, in December 2015, over 190 countries, including the United States, reached an agreement to reduce global greenhouse gas emissions. To the extent the United States or any other country implement this agreement or impose other climate change regulations on the oil and gas industry, it could have an adverse direct or indirect effect on our business.

Water discharge. The Clean Water Act, as amended (the "CWA"), and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into regulated waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. The CWA and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including jurisdictional wetlands, unless authorized by an appropriately issued permit. The CWA also requires the development and implementation of spill prevention, control and countermeasures, including the construction and maintenance of containment berms and similar structures, if required, to help prevent the contamination of regulated waters in the event of a petroleum hydrocarbon tank spill, rupture or leak at such facilities. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. Federal and state regulatory agencies can impose administrative, civil and criminal penalties as well as other enforcement mechanisms for non-compliance with discharge permits or other requirements of the CWA and analogous state laws and regulations.

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Safe Drinking Water Act. Although we do not directly engage in hydraulic fracturing activities, our customers purchase our frac sand for use in their hydraulic fracturing operations. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into the formation to stimulate gas production. Legislation to amend the Safe Drinking Water Act (the "SDWA") to repeal the exemption for hydraulic fracturing from the definition of "underground injection" and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, were proposed in recent sessions of Congress and Congress continues to consider legislation to amend the SDWA. We cannot predict whether any such legislation will ever be enacted and, if so, what its provisions would be. Scrutiny of hydraulic fracturing activities continues in other ways, with the EPA having commenced a multi-year study of the potential environmental impacts of hydraulic fracturing, with a final draft of the report released in 2015 for peer review and comment, and the U.S. Department of Energy having released a series of recommendations for improving the safety of the process in 2011. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms. Further, the EPA and the U.S. Department of the Interior (the "DOI") have proposed and adopted new regulations for certain aspects of the process. For example, the EPA proposed effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing. The DOI adopted rules that require disclosure of chemicals used in hydraulic fracturing activities upon federal and Indian lands and also would strengthen standards for well-bore integrity and the management of fluids that return to the surface during and after fracturing operations on federal and Indian lands (although implementation of this rule has been stayed pending the resolution of legal challenges). At the state level, some states, including Texas, have adopted, and other states are considering adopting, legal requirements that could impose more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing activities. If additional levels of regulation and permits were required through the adoption of new laws and regulations at the federal or state level, that could lead to delays, increased operating costs and process prohibitions that could make it more difficult to complete natural gas wells in shale formations, increasing our customers' costs of compliance and doing business and otherwise adversely affect the hydraulic fracturing services they perform, which could negatively impact demand for our frac sand products. In addition, heightened political, regulatory and public scrutiny of hydraulic fracturing practices could potentially expose us or our customers to increased legal and regulatory proceedings, and any such proceedings could be time-consuming, costly or result in substantial legal liability or significant reputational harm. Any such developments could have a material adverse effect on our business, financial condition and results of operations, whether directly or indirectly. For example, we could be directly affected by adverse litigation involving us, or indirectly affected if the cost of compliance limits the ability of our customers to operate in the geographic areas we serve.

Solid waste. The Resource Conservation and Recovery Act, as amended (the "RCRA"), and comparable state laws control the management and disposal of hazardous and non-hazardous waste. These laws and regulations govern the generation, storage, treatment, transfer and disposal of wastes that we generate including, but not limited to, used oil, antifreeze, filters, sludges, paint, solvents and sandblast materials. The EPA and various state agencies have limited the approved methods of disposal for these types of wastes. In the course of our operations, we generate waste that may be regulated as non-hazardous wastes or even hazardous wastes, obligating us to comply with applicable RCRA standards relating to the management and disposal of such wastes.

Site remediation. The Comprehensive Environmental Response, Compensation and Liability Act, as amended ("CERCLA"), and comparable state laws impose strict, joint and several liability without regard to fault or the legality of the original conduct on certain classes of persons that contributed to the release of a hazardous substance into the environment. These persons include the owner and operator of a disposal site where a hazardous substance release occurred and any company that transported, disposed of, or arranged for the transport or disposal of hazardous substances released at the site. Under CERCLA, such persons may be liable for the costs of remediating the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. In addition, where contamination may be present, it is not uncommon for the neighboring landowners and other third parties to file claims for personal injury, property damage and recovery of response costs. On November 21, 2013, the EPA issued a General Notice Letter and Information Request ("Notice") under Section 104(e) of CERCLA to one of our subsidiaries operating within the Fuel segment. The Notice provides that the subsidiary may have incurred liability with respect to the Reef Environmental site in Alabama, and requested certain information in accordance with Section 107(a) of CERCLA. The subsidiary timely responded to the Notice. At this time, no specific claim for cost recovery has been made by the EPA (or any other potentially responsible party) against the Partnership. There is uncertainty relating to our share of environmental remediation liability, if any, because our allocable share of wastewater is unknown and the total remediation cost is also unknown. Consequently, management is unable to estimate the possible loss or range of loss, if any. We have not recorded a loss contingency accrual in our financial statements. In the opinion of management, the outcome of such matters will not have a material adverse effect on our financial position, liquidity, or results of operations.

The soil and groundwater associated with and adjacent to our former Dallas-Fort Worth terminal property have been affected by prior releases of petroleum products or other contaminants. A past owner and operator of the terminal property, ConocoPhillips, has been working with TCEQ to address this contamination. We, ConocoPhillips and owners and operators of adjacent industrial properties undertaking unrelated remediation obtained a Municipal Setting Designation (“MSD”) from the City of Fort Worth, which is an ordinance prohibiting the use of groundwater as drinking water in the area of our former terminal property. Following

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the certification of this MSD by the TCEQ, ConocoPhillips obtained approval of a remedial action plan for the property, which now only requires recordation of a restrictive covenant to comply with the TCEQ requirements. In connection with the sale of this facility, we have agreed to hold our successor harmless from any claims arising from this contamination, none of which has been asserted to our knowledge. We do not believe this former facility is likely to present any material liability to us.

Endangered Species. The Endangered Species Act (“ESA”), restricts activities that may affect endangered or threatened species or their habitats. The designation of certain species has not caused us to incur material costs or become subject to operating restrictions or bans. However, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans or limit future development activity in the affected areas. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia on September 9, 2011, the U.S. Fish and Wildlife Service is required to consider listing more than 250 species as endangered under the Endangered Species Act. Under the September 9, 2011 settlement, the U.S. Fish and Wildlife Service is required to review and address the needs of more than 250 species on the candidate list before the completion of the agency's 2017 fiscal year. The designation of previously unprotected species as threatened or endangered in areas where our exploration and production customers operate could cause us or our customers to incur increased costs arising from species protection measures and could result in delays or limitations in our customers' performance of operations, which could reduce demand for our services.

Mining and Workplace Safety. Our sand mining operations are subject to mining safety regulation. The U.S. Mine Safety and Health Administration (“MSHA”) is the primary regulatory organization governing the frac sand industry. Accordingly, MSHA regulates quarries, surface mines, underground mines and the industrial mineral processing facilities associated with quarries and mines. The mission of MSHA is to administer the provisions of the Federal Mine Safety and Health Act of 1977 and to enforce compliance with mandatory worker safety and health standards. MSHA works closely with the Industrial Minerals Association, a trade association in which we have a significant leadership role, in pursuing this mission. As part of MSHA's oversight, representatives perform at least two unannounced inspections annually for each aboveground facility. To date these inspections have not resulted in any citations for material violations of MSHA standards.

We also are subject to the requirements of the U.S. Occupational Safety and Health Act (“OSHA”), and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA Hazard Communication Standard requires that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and the public. OSHA regulates the customers and users of frac sand and provides detailed regulations requiring employers to protect employees from overexposure to silica through the enforcement of permissible exposure limits and the OSHA Hazard Communication Standard.

Local Regulation. As demand for frac sand in the oil and natural gas industry has driven a significant increase in current and expected future production of frac sand, some local communities have expressed concern regarding silica sand mining operations. These concerns have generally included exposure to ambient silica sand dust, truck traffic, water usage and blasting. In response, certain state and local communities have developed or are in the process of developing regulations or zoning restrictions intended to minimize dust from becoming airborne, control the flow of truck traffic, significantly curtail the amount of practicable area for mining activities, provide compensation to local residents for potential impacts of mining activities and, in some cases, ban issuance of new permits for mining activities. To date, we have not experienced any material impact to our existing mining operations or planned capacity expansions as a result of these types of concerns. We are not aware of any proposals for significant increased scrutiny on the part of state or local regulators in the jurisdictions in which we operate or community concerns with respect to our operations that would reasonably be expected to have a material adverse effect on our business, financial condition or results of operations going forward.

Employees

We have no employees. All of our management, administrative and operating functions are performed by employees of Emerge Energy Services GP, LLC, which is our general partner. As of December 31, 2015, our general partner employed 202 full-time employees who provide these services for us. None of these employees are subject to

collective bargaining agreements. We consider our employee relations to be good.
Available Information
We file annual, quarterly, and current reports and other documents with the SEC under the Securities and Exchange Act of 1934. We provide access free of charge to all of our SEC filings, as soon as practicable after they are filed or furnished, through our Internet website located at www.emergelp.com. References to our website addressed in this Annual Report on Form 10-K are provided as a convenience and do not constitute, and should not be viewed as, an incorporation by reference of the information contained on, or available through, the website.
You may also read and copy any of these materials at the SEC's Public Reference Room at 100 F. Street, NE, Room 1580, Washington, D.C. 20549. Information on the operation of the Public Reference Room is available by calling the SEC at 1-800-

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SEC-0330. Alternatively, the SEC maintains an Internet site (www.sec.gov) that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC.

Investors and others should note that we announce material financial information to investors using investor relations websites, press releases, SEC filings and public conference calls and webcasts. We also intend to also use Twitter (https://twitter.com/emergelp) as a means of disclosing information about our company, services and other matters. It is possible that the information we disclose could be deemed to be material information. Therefore, we encourage investors, the media and others interested in our company to review the information we post on Twitter.

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ITEM 1A. RISK FACTORS

Limited partner interests are inherently different from capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in the frac sand or refined products businesses. You should consider carefully the following risk factors together with all of the other information included in this report in evaluating an investment in our common units.

If any of the following risks were to occur, our business, financial condition or results of operations could be materially adversely affected. In that case, we may be unable to make distributions on our common units, the trading price of our common units could decline, and you could lose all or part of your investment.

Risks Related to Our Business

We may not have sufficient available cash to pay any quarterly distribution on our common units.

We may not have sufficient available cash each quarter to enable us to pay any distributions to our unitholders. For example, the board of directors of our general partner determined that we did not generate sufficient available cash to distribute to our unitholders during the quarters ended September 30, 2015 and December 31, 2015. Furthermore, our partnership agreement does not require us to pay distributions on a quarterly basis or otherwise. The amount of cash we can distribute to our unitholders principally depends upon the amount of cash we generate from our operations, which fluctuates from quarter to quarter based on, among other things:

- the level of production of, demand for, and price of frac sand and oil, natural gas, gasoline, diesel, biodiesel and other refined products, particularly in the markets we serve;
- the fees we charge, and the margins we realize, from our frac sand and fuel products sales and the other services we provide;
- changes in laws and regulations (or the interpretation thereof) related to the mining and oil and natural gas industries, silica dust exposure or the environment;
- the level of competition from other companies;
- the cost and time required to execute organic growth opportunities;
- difficulty collecting receivables; and
- prevailing global and regional economic and regulatory conditions, and their impact on our suppliers and customers.

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

- the levels of our maintenance capital expenditures and growth capital expenditures;
- the level of our operating costs and expenses;
- our debt service requirements and other liabilities;
- fluctuations in our working capital needs;
- restrictions contained in our revolving credit facility and other debt agreements to which we are a party;
- the cost of acquisitions, if any;
- fluctuations in interest rates;
- our ability to borrow funds and access capital markets; and
- the amount of cash reserves established by our general partner.

Our partnership agreement does not require us to pay a minimum quarterly distribution. The amount of distributions that we pay, if any, and the decision to pay any distribution at all, are determined by the board of directors of our general partner. Our quarterly distributions, if any, are subject to significant fluctuations based on the above factors.

The amount of cash we have available for distribution to unitholders depends primarily on our cash flow and not solely on profitability.

You should be aware that the amount of cash we have available for distribution depends primarily upon our cash flow, including cash flow from financial reserves and working capital borrowings, and not solely on profitability, which is affected by non-cash items. As a result, we may not be able to make cash distributions during periods in which we record net income.

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The amount of our quarterly cash distributions, if any, may vary significantly both quarterly and annually and will be directly dependent on the performance of our business. Unlike most publicly traded partnerships, we do not have a minimum quarterly distribution or employ structures intended to consistently maintain or increase distributions over time.

Investors who are looking for an investment that will pay regular and predictable quarterly distributions should not invest in our common units. We expect our business performance may be more volatile, and our cash flows may be less stable, than the business performance and cash flows of most publicly traded partnerships. As a result, our quarterly cash distributions may be volatile and may vary quarterly and annually. Unlike most publicly traded partnerships, we do not have a minimum quarterly distribution or employ structures intended to consistently maintain or increase distributions over time. The amount of our quarterly cash distributions is directly dependent on the performance of our business. Because our quarterly distributions will significantly correlate to the cash we generate each quarter after payment of our fixed and variable expenses, quarterly distributions paid to our unitholders may vary significantly from quarter to quarter and may be zero.

The board of directors of our general partner may modify or revoke our cash distribution policy at any time at its discretion. Our partnership agreement does not require us to make any distributions at all.

The board of directors of our general partner adopted a cash distribution policy pursuant to which we distribute all of the available cash we generate each quarter to unitholders of record on a pro rata basis. However, the board may change such policy at any time at its discretion and could elect not to make distributions for one or more quarters. For example, the board of directors of our General Partner determined not to make a cash distribution on our common units for the three months ended September 30, 2015 and December 31, 2015. Our partnership agreement does not require us to make any distributions at all. Accordingly, investors are cautioned not to place undue reliance on the permanence of such a policy in making an investment decision. Any modification or revocation of our cash distribution policy could substantially reduce or eliminate the amounts of distributions to our unitholders.

Our operations are subject to the cyclical nature of our customers' businesses and depend upon the continued demand for crude oil and natural gas.

Our frac sand sales are to customers in the oil and natural gas industry, a historically cyclical industry. This industry was adversely affected by the uncertain global economic climate in the second half of 2008 and in 2009. Natural gas, crude oil and NGL prices declined significantly in the second half of 2014 and have been negatively affected by a combination of factors, including weakening demand, increased production, the decision by the Organization of Petroleum Exporting Countries (“OPEC”) 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 could continue for the foreseeable future. Natural gas prices have generally remained below $4.50 per mcf for the past six years and below $3.00 per mcf since early 2015. Worldwide economic, political and military events, including war, terrorist activity, events in the Middle East and initiatives by OPEC have contributed, and are likely to continue to contribute, to commodity price volatility. Additionally, warmer than normal winters in North America and other weather patterns may adversely impact the short-term demand for oil and natural gas and, therefore, demand for our products.

During periods of economic slowdown and long-term reductions in oil and natural gas prices, oil and natural gas exploration and production companies often reduce their oil and natural gas production rates and also reduce capital expenditures and defer or cancel pending projects, which results in decreased demand for our frac sand. Such developments occur even among companies that are not experiencing financial difficulties. Similarly, demand for our refined fuel products is lower during times of economic slowdown. A continued or renewed economic downturn in one or more of the industries or geographic regions that we serve, or in the worldwide economy, could adversely affect our results of operations. In addition, any future decreases in the rate at which oil and natural gas reserves are discovered or developed, whether due to increased governmental regulation, limitations on exploration and drilling activity, a sustained decline in oil and natural gas prices, or other factors, could have a material adverse effect on our business, even in a stronger natural gas and oil price environment.

Our Sand operations are subject to operating risks that are often beyond our control and could adversely affect production levels and costs.

Our mining, processing and production facilities are subject to risks normally encountered in the frac sand industry. These risks include:

- changes in the price and availability of transportation;
- inability to obtain necessary production equipment or replacement parts;
- inclement or hazardous weather conditions, including flooding, and the physical impacts of climate change;
- unusual or unexpected geological formations or pressures;
- unanticipated ground, grade or water conditions;

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- inability to acquire or maintain necessary permits or mining or water rights;
- labor disputes and disputes with our excavation contractors;
- late delivery of supplies;
- changes in the price and availability of natural gas or electricity that we use as fuel sources for our frac sand plants and equipment;
- technical difficulties or failures;
- cave-ins or similar pit wall failures;
- environmental hazards, such as unauthorized spills, releases and discharges of wastes, tank ruptures and emissions of unpermitted levels of pollutants;
- industrial accidents;
- changes in laws and regulations (or the interpretation thereof) related to the mining and oil and natural gas industries, silica dust exposure or the environment;
- inability of our customers or distribution partners to take delivery;
- reduction in the amount of water available for processing;
- fires, explosions or other accidents; and
- facility shutdowns in response to environmental regulatory actions.

Any of these risks could result in damage to, or destruction of, our mining properties or production facilities, personal injury, environmental damage, delays in mining or processing, losses or possible legal liability. Any prolonged downtime or shutdowns at our mining properties or production facilities could have a material adverse effect on us. Not all of these risks are reasonably insurable, and our insurance coverage contains limits, deductibles, exclusions and endorsements. Our insurance coverage may not be sufficient to meet our needs in the event of loss, and any such loss may have a material adverse effect on us.

We may be adversely affected by decreased demand for frac sand or the development of either effective alternative proppants or new processes to replace hydraulic fracturing.

Frac sand is a proppant used in the completion and re-completion of natural gas and oil wells through hydraulic fracturing. Frac sand is the most commonly used proppant and is less expensive than ceramic proppant, which is also used in hydraulic fracturing to stimulate and maintain oil and natural gas production. A significant shift in demand from frac sand to other proppants, such as ceramic proppants, could have a material adverse effect on our financial condition and results of operations. The development and use of other effective alternative proppants, or the development of new processes to replace hydraulic fracturing altogether, could also cause a decline in demand for the frac sand we produce and could have a material adverse effect on our financial condition and results of operations.

We may be adversely affected by a reduction in horizontal drilling activity or the development of either effective alternative proppants or new processes to replace hydraulic fracturing.

Frac sand is a proppant used in the completion and re-completion of natural gas and oil wells through the process of hydraulic fracturing. Frac sand is the most commonly used proppant and is less expensive than ceramic and resin coated proppants, which are also used in the hydraulic fracturing process to stimulate and maintain oil and natural gas production. A significant shift in demand from frac sand to other proppants, such as resin coated sand and ceramic alternatives, could have a material adverse effect on our business, financial condition and results of operations. In addition, demand for frac sand is substantially higher in the case of horizontally drilled wells, which allow for multiple hydraulic fractures within the same well bore but are more expensive to develop than vertically drilled wells. The development and use of a cheaper, more effective alternative proppant, a reduction in horizontal drilling activity or the development of new processes to replace hydraulic fracturing altogether, could also cause a decline in demand for the frac sand we produce and could have a material adverse effect on our business, financial condition and results of operations. A reduction in demand for the frac sand we produce may cause our contractual arrangements to become economically unattractive and could have a material adverse effect on our business, financial condition, and results of operations.

A large portion of our sales in each of our Sand segment and our Fuel segment is generated by a few large customers, and the loss of our largest customers or a significant reduction in purchases by those customers could adversely affect our operations.

During 2015, our top five Sand customers represented 61% of sales from our Sand operations. During 2015, our top five Fuel customers represented 24% of sales from our Fuel operations. In our Fuel segment, we derive a significant portion of our revenues

from sales to contract customers and the terms of our contracts are typically for one year or less. Our customers who are not subject to firm contractual commitments may not continue to purchase the same levels of our products in the future due to a variety of reasons. For example, some of our top customers could go out of business or, alternatively, be acquired by other companies that purchase the same products and services provided by us from other third-party providers. Our Sand customers could also seek to capture and develop their own sources of frac sand. In addition, some of our customers may be highly leveraged and subject to their own operating and regulatory risks. If any of our major customers substantially reduces or altogether ceases purchasing our products, we could suffer a material adverse effect on our business, financial condition, results of operations, cash flows, and prospects. In addition, upon the expiration or termination of our existing contracts, we may not be able to enter into new contracts at all or on terms as favorable as our existing contracts. We may also choose to renegotiate our existing contracts on less favorable terms (including with respect to price and volumes) in order to preserve relationships with our customers.
In addition, the long-term sales agreements we have for our frac sand may negatively impact our results of operations. Certain of our long-term agreements are for sales at fixed prices that are adjusted only for certain cost increases. As a result, in periods with increasing frac sand prices, our contract prices may be lower than prevailing industry spot prices. Our long-term sales agreements also contain provisions that allow prices to be adjusted downwards in the event of falling industry prices.
Any material nonpayment or nonperformance by any of our key customers could have a material adverse effect on our business and results of operations and our ability to make cash distributions to our unitholders.
Any material nonpayment or nonperformance by any of our key customers could have a material adverse effect on our revenue and cash flows and our ability to make cash distributions to our unitholders. Our long-term take-or-pay sales agreements with select customers contain provisions designed to compensate us, in part, for our lost margins on any unpurchased volumes; accordingly, in such circumstances, we would be paid less than the price per ton we would receive if our customers purchased the contractual tonnage amounts. Certain of our other long-term frac sand sales agreements provide for minimum tonnage orders by our customers but do not contain pre-determined liquidated damage penalties in the event the customers fail to purchase designated volumes. Instead, we would seek legal remedies against the non-performing customer or seek new customers to replace our lost sales volumes. Certain of our other long-term frac sand supply contracts are efforts-based and therefore do not require the customer to purchase minimum volumes of frac sand from us or contain take-or-pay provisions.
Our different types of contracts with our frac sand customers provide for different potential remedies to us in the event a customer fails to purchase the minimum contracted amount of frac sand in a given period. If we were to pursue legal remedies in the event a customer failed to purchase the minimum contracted amount of sand under a fixed-volume contract or failed to satisfy the take-or-pay commitment under a take-or-pay contract, we may receive significantly less in a judgment or settlement of any claimed breach than we would have received had the customer fully performed under the contract. In the event of any customer's breach, we may also choose to renegotiate any disputed contract on less favorable terms (including with respect to price and volumes) to us to preserve the relationship with that customer. Accordingly, any material nonpayment or performance by our customers could have a material adverse effect on our revenue and cash flows and our ability to make distributions to our unitholders.
Our long-term contracts may preclude us from taking advantage of increasing prices for frac sand or mitigating the effect of increased operational costs during the term of our long-term contracts, even though certain volumes under our long-term contracts are subject to annual fixed price escalators.
The long-term supply contracts we have may negatively impact our results of operations in future periods. Our long-term contracts require our customers to pay a specified price for a specified volume of frac sand each month. As a result, in periods with increasing prices, our sales may not keep pace with market prices. Additionally, if our operational costs increase during the terms of our long-term supply contracts, we may not be able to pass any of those increased costs to our customers. If we are unable to otherwise mitigate these increased operational costs, our net income and available cash for distributions could decline.
The credit risks of our concentrated customer base could result in losses.
Many of our Sand segment customers are oil and gas companies that are facing 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 disruption, we may incur increased exposure to credit risk and bad debts. If we fail to adequately assess the creditworthiness of existing or future customers or unanticipated deterioration in their creditworthiness, any resulting increase in nonpayment or nonperformance by them and our inability to re-market or otherwise use the production could have a material adverse effect on our business, financial condition, results of operations and ability to pay distributions to our unitholders.

Certain of our contracts contain provisions requiring us to meet minimum obligations to our customers and suppliers. If we are unable to meet our minimum requirements under these contracts, we may be required to pay penalties or the contract counterparty may be able to terminate the agreement.

In certain instances, we commit to deliver products to our customers prior to production, under penalty of nonperformance. Depending on the contract, our inability to deliver the requisite tonnage of frac sand may permit our customers to terminate the agreement or require us to pay our customers a fee, the amount of which would be based on the difference between the amounts of tonnage contracted for and the amount delivered. We have significant long-term operating leases for railcars, both currently in service and yet to be delivered, under which we would still be obligated to pay despite any future decrease in the number of railcars needed to conduct our operations. Further, our agreement with Canadian National requires us to provide minimum volumes of frac sand for shipping on the Canadian National line. If we do not provide the minimum volume of frac sand for shipping, we will be required to pay a per-ton shortfall penalty, subject to certain exceptions. In addition, under our agreements with sand suppliers, we are obligated to order a minimum amount of wet sand per year or pay fees on the difference between the minimum and the amount we actually order. Similarly, we would be required to make minimum payments to mineral rights owners at certain of our mines in the event we purchase less than the minimum volumes of sand specified under the particular royalty agreement in place. If we are unable to meet our obligations under any of these agreements, we may have to pay substantial penalties or the agreements may become subject to termination, as applicable. In such events, our business, financial condition, and results of operations may be materially adversely affected.

Fuel prices and costs are volatile, and we have unhedged commodity price exposure between the time we purchase fuel supplies and the time we sell our product that may reduce our profit margins.

Our financial results from our Fuel segment are strongly affected by the relationship, or margin, between the prices we charge our customers for fuel and the prices we pay for transmix, wholesale fuel, and other feedstocks. We purchase our transmix, wholesale fuel and other feedstocks based on several different regional refined product price indices, the most important of which are the Platts Gulf Coast gasoline and diesel price postings. The costs of our purchases are generally set on the day that we purchase the products. We typically sell our fuel products within 7 to 10 days of our supply purchases at then prevailing market prices; however, the length of time that we hold inventory may increase due to events beyond our control, such as adverse economic conditions or a slowdown in pipeline transit times. During the period we have title to products that are held in inventory for processing and/or resale, we will be exposed to commodity price risk. Furthermore, the longer our fuel products remain in our inventory, the greater our exposure to commodity price risk. If the market price for our fuel products declines during this period or generally does not increase commensurate with any increases in our supply and processing costs, our margins will fall and the amount of cash we will have available for distribution will decrease. In addition, because our inventory is valued at the lower of cost or market value, if the market value of our inventory were to decline to an amount less than our cost, we would record a write-down of inventory and a non-cash charge to cost of sales. In a period of decreasing transmix or refined product prices, our inventory valuation methodology may result in decreases in our reported net income and cash available for distribution to unitholders.

We also follow a financial hedging program whereby we hedge a portion of our gasoline and diesel inventory, which is intended to reduce our commodity price exposure on some of our activities in our Fuel segment. Even though we enter into hedging arrangements to reduce our commodity price exposure, we cannot guarantee that such arrangements will provide sufficient price protection or that our counterparties will be able to perform under them, such as in the case of a counterparty's insolvency.

Failure to maintain effective quality control systems at our mining, processing and production facilities could have a material adverse effect on our business and operations.

The performance, quality, and safety of our products are critical to the success of our business. For instance, our frac sand must meet stringent International Organization for Standardization, or ISO, and API technical specifications, including sphericity, grain size, crush resistance, acid solubility, purity, and turbidity, as well as customer specifications, in order to be suitable for hydraulic fracturing purposes. If our frac sand fails to meet such specifications or our customers' expectations, we could be subject to significant contractual damages or contract terminations and face serious harm to our reputation, and our sales could be negatively affected. The performance, quality, and safety of our products depend significantly on the effectiveness of our quality control systems, which, in turn, depends on a number of factors, including the design of our quality control systems, our quality-training program and our ability to ensure that our employees adhere to our quality control policies and guidelines. Any significant failure or deterioration of our quality control systems could have a material adverse effect on our business, financial condition, results of operations and reputation.

Increasing costs or a lack of dependability or availability of transportation services or infrastructure could have an adverse effect on our ability to deliver our frac sand products at competitive prices.

Because of the relatively low cost of producing frac sand, transportation and handling costs tend to be a significant component of the total delivered cost of sales. The bulk of our currently contracted sales involve our customers also contracting with truck and rail services to haul our frac sand to end users. If there are increased costs under those contracts, and our customers are not able

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to pass those increases along to end users, our customers may find alternative providers. We have provided fee-based transportation and logistics (including railcar procurement, freight management, and product storage) services for both our spot market and contract customers. Should we fail to properly manage the customer's logistics needs under those instances where we have agreed to provide them, we may face increased costs, and our customers may choose to purchase sand from other suppliers. Labor disputes, derailments, adverse weather conditions or other environmental events, tight railcar leasing markets and changes to rail freight systems could interrupt or limit available transportation services. A significant increase in transportation service rates, a reduction in the dependability or availability of transportation services or relocation of our customers' businesses to areas that are not served by the rail systems accessible from our production facilities could impair our customers' ability to access our products and our ability to expand our markets.

We face significant competition that may cause us to lose market share and reduce our ability to make distributions to our unitholders.

The frac sand and refined products industries are highly competitive. The frac sand market is characterized by a small number of large, national producers and a larger number of small, regional, or local producers. Competition in this industry is based on price, consistency and quality of product, site location, distribution capability, customer service, reliability of supply, breadth of product offering and technical support.

Some of our competitors have greater financial and other resources than we do. In addition, our larger competitors may develop technology superior to ours or may have production facilities that offer lower-cost transportation to certain specific customer locations than we do. In recent years there has been an increase in the number of small, regional producers servicing the frac sand market due to an increased demand for hydraulic fracturing services and to the growing number of unconventional resource formations being developed in the United States. Should the demand for hydraulic fracturing services decrease or the supply of frac sand available in the market increase, prices in the frac sand market could materially decrease as less-efficient producers exit the market, selling frac sand at below market prices. Furthermore, oil and natural gas exploration and production companies and other providers of hydraulic fracturing services have acquired and in the future may acquire their own frac sand reserves to fulfill their proppant requirements, and these other market participants may expand their existing frac sand production capacity, all of which would negatively impact demand for our frac sand products. In addition, increased competition in the frac sand industry could have an adverse impact on our ability to enter into long-term contracts or to enter into contracts on favorable terms.

Our competitors in the refined products industry include large, integrated, major, or independent oil companies that, because of their more diverse operations and stronger capitalization, may be better positioned than we are to withstand volatile industry conditions, including shortages or excesses of crude oil, transmix or refined products or intense price competition at the wholesale level. Additionally, the two largest processors of transmix have substantial financial and operational resources. These processors may choose to invest in additional transmix processing capacity and compete with us directly in our core markets.

Our cash flows fluctuate on a seasonal basis and severe weather conditions could have a material adverse effect on our business.

Because raw sand cannot be wet-processed during extremely cold temperatures, frac sand is typically washed only eight months out of the year at our Wisconsin operations. Our inability to wash frac sand year round in Wisconsin results in a seasonal build-up of inventory as we excavate excess sand to build a stockpile that will feed the dry plant during the winter months. This seasonal build-up of inventory causes our average inventory balance to fluctuate from a few weeks in early spring to more than 100 days in early winter. As a result, the cash flows of our Sand operations fluctuate on a seasonal basis based on the length of time Wisconsin wet plant operations must remain shut down due to harsh winter weather conditions. We may also be selling frac sand for use in oil and gas-producing basins where severe weather conditions may curtail drilling activities and, as a result, our sales volumes to customers in those areas may be adversely affected. For example, we could experience a decline in volumes sold for the second quarter relative to the first quarter each year due to seasonality of frac sand sales to customers in western Canada as sales volumes are generally lower during the months of April and May due to limited drilling activity as a result of that region's annual thaw. Unexpected winter conditions (if winter comes earlier than expected or lasts longer than expected) may lead to us not having a sufficient sand stockpile to supply feedstock for our dry plant during winter months and result in us being unable to meet our contracted sand deliveries during such time, or may drive frac sand sales volumes down by affecting drilling activity among our customers, each of which could lead to a material adverse effect on our business, financial condition, results of operation and reputation. The inability of our logistics partners, including rail companies, to manage their own operations efficiently during inclement weather could have an effect on our ability to serve our customers where we are relying on our logistics partners to provide certain transportation services.

Diminished access to water may adversely affect our operations and the operations of our customers.

While much of our process water is recycled and recirculated, the mining and processing activities in which we engage at our wet plant facilities require significant amounts of water. During extreme drought conditions, some of our facilities are located in areas that can become water-constrained. We have obtained water rights and have installed high capacity wells on our properties that we currently use to service the activities on our properties, and we plan to obtain all required water rights to service other properties we may develop or acquire in the future. However, the amount of water that we are entitled to use pursuant to our water rights must be determined by the appropriate regulatory authorities in the jurisdictions in which we operate. Such regulatory authorities may amend the regulations regarding such water rights, increase the cost of maintaining such water rights or eliminate our current water rights, and we may be unable to retain all or a portion of such water rights. Such changes in laws, regulations or government policy and related interpretations pertaining to water rights may alter the environment in which we do business, which may negatively affect our financial condition and results of operations.

Similarly, our customers' performance of hydraulic fracturing activities may require the use of large amounts of water. The ability of our customers' to obtain the necessary amounts of water sufficient to perform hydraulic fracturing activities may well depend on those customers ability to acquire water by means of contract, permitting, or spot purchase. The ability of our customers to obtain and maintain sufficient levels of water for these fracturing activities are similarly subject to regulatory authority approvals, changes in applicable laws or regulations, potentially differing interpretations of contract terms, increases in costs to provide such water, and even changes in weather that could make such water resources more scarce.

We depend on certain transmix and wholesale fuels suppliers for a significant portion of our transmix and wholesale fuels, and the loss of any of these key suppliers or a material decrease in the supply of transmix or wholesale fuels generally available to us could materially reduce our ability to make distributions to unitholders.

We purchase transmix from major oil companies, brokers, and local retailers in Texas and Alabama. We currently purchase approximately 59% of our supply of transmix pursuant to contracts with terms ranging from 12 to 48 months and a volume-weighted average remaining duration of approximately 11.75 months as of December 31, 2015. For the year ended December 31, 2015, our three largest suppliers of transmix accounted for 17%, 13%, and 8% of our total transmix purchases. The contract with our largest supplier for the year ended December 31, 2015 expires in September 2017; purchases from our second largest supplier are made pursuant to a month-to-month contract; and the contract with our third largest supplier expired in December 2015. To the extent that our suppliers reduce the volumes of transmix and wholesale fuels that they supply us as a result of declining production, other changes in refinery output or refining transportation and marketing strategies, competition or otherwise, or if our suppliers decide not to renew our supply contracts, our revenues, net income and cash available for distribution could decline unless we were able to acquire comparable supplies of transmix and wholesale fuels on comparable terms from other suppliers. In addition, our earnings would be adversely affected if a significant supply of transmix was no longer available due to refinery or pipeline closings or interruptions or other force majeure events.

We are dependent on certain third-party pipelines for transportation of our wholesale products, and if these pipelines become unavailable to us, our revenues and cash available for distribution could decline.

Our processing facilities in Texas and Alabama are each interconnected to two pipelines that supply all of our wholesale products. Additionally, we periodically receive transmix at our Texas facility on an additional pipeline. Since we do not own or operate any of these pipelines, their continuing operation is not within our control. If any of these third-party pipelines were to become partially or fully unavailable to transport products because of accidents, extreme weather conditions, government regulation, terrorism or other events, or if the rates or terms and conditions of service of any of these third-party pipelines were to change materially, our revenues, net income and cash available for distribution could decline.

Increases in the price of diesel fuel may adversely affect our Sand segment results of operations.

Diesel fuel costs generally fluctuate with increasing and decreasing world crude oil prices, and accordingly are subject to political, economic and market factors that are outside of our control. Our Sand segment operations are dependent on earthmoving equipment, railcars, and trucks, and diesel fuel costs are a significant component of the operating expense of these vehicles. We contract with a third party industrial mining expert to excavate raw frac sand, deliver the raw frac sand to our processing facility, move the sand from our wet plant to our dry plant, and we pay a fixed price per ton of sand delivered to our wet plant, subject to a fuel surcharge based on the price of diesel fuel. Accordingly, increased diesel fuel costs at our Sand segment could have an adverse effect on our results of operations and cash flows.

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

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

- develop new business and enter into contracts with new customers;
- retain our existing customers and maintain or expand the level of services we provide them;
- identify and obtain additional frac sand reserves;
- recruit and train qualified personnel and retain valued employees;

- expand our geographic presence;
- effectively manage our costs and expenses, including costs and expenses related to growth;
- consummate accretive acquisitions;
- obtain required debt or equity financing for our existing and new operations;
- meet customer-specific contract requirements or pre-qualifications;
- obtain permits from federal, state and local regulatory authorities; and
- make assumptions about mineral reserves, future production, sales, capital expenditures, operating expenses and costs, including synergies.

If we do not achieve our expected growth, we may not be able to achieve our estimated results and, as a result, we would not be able to pay the estimated annual distribution, in which event the market price of our common units will likely decline materially.

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

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

Growing our business by constructing new plants and facilities subjects us to construction risks as well as market risks relating to insufficient demand for the services of such plants and facilities upon completion thereof.

One of the ways we intend to grow our business is through the construction of new dry plants, wet plants, and transload facilities in our Sand segment. The construction of such facilities requires the expenditure of significant amounts of capital, which may exceed our resources, and involves numerous regulatory, environmental, political, and legal uncertainties. If we undertake these projects, we may not be able to complete them on schedule or at all or at the budgeted cost. Moreover, our revenues may not increase upon the expenditure of funds on a particular project. For instance, if we build a new plant or facility, the construction will occur over an extended period of time, and we will not receive any material increases in revenues until at least after completion of the project, if at all. Moreover, we may construct new plants or facilities to capture anticipated future demand in a region in which anticipated market conditions do not materialize or for which we are unable to acquire new customers. As a result, new plants or facilities may not be able to attract enough demand to achieve our expected investment return, which could materially and adversely affect our results of operations and financial condition.

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

We will distribute 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 revolving credit facility and the issuance of debt and equity securities, to maintain our asset base and 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. To the extent we issue additional units in connection with other growth capital expenditures, such issuances may result in significant dilution to our existing unitholders and 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.

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

We have a $350 million revolving credit facility with outstanding borrowings of $302.1 million as of December 31, 2015. Our facility also has an accordion feature for an additional $150 million. Our ability to incur additional debt is subject to limitations under our revolving credit facility. Our level of debt has important consequences to us, including the following:

- our ability to obtain additional financing, if necessary, for operating working capital, capital expenditures, acquisitions or other purposes may be impaired by our debt level, or such financing may not be available on favorable terms;
- we need a portion of our cash flow to make payments on our indebtedness, reducing the funds that would otherwise be available for operations, future business opportunities and distributions; and
- our debt level makes us more vulnerable than our competitors with less debt to competitive pressures or a downturn in our business or the economy generally.

Our ability to service our debt depends upon, among other things, our future financial and operating performance, which is affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control. In addition, our ability to service our debt under our revolving credit facility depends on market interest rates, since the interest rates applicable to our borrowings fluctuate with movements in interest rate markets. 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, restructuring or refinancing our debt, or seeking additional equity capital. We may be unable to effect any of these actions on satisfactory terms, or at all.

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

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

- grant liens;
- incur additional indebtedness;
- engage in a merger, consolidation or dissolution;
- enter into transactions with affiliates;
- sell or otherwise dispose of assets, businesses and operations;
- materially alter the character of our business as conducted at the closing of this offering; and
- make acquisitions, investments and capital expenditures.

Furthermore, our revolving credit facility contains certain operating and financial covenants. Our ability to comply with the covenants and restrictions contained in the revolving credit facility may be affected by events beyond our control, including prevailing economic, financial and industry conditions. If market or other economic conditions deteriorate, our ability to comply with these covenants may be impaired. If we violate any of the restrictions, covenants, ratios or tests a significant portion of our indebtedness may become immediately due and payable, our lenders' commitment to make further loans to us may terminate, and we will be prohibited from making distributions to our unitholders. We might not have, or be able to obtain, sufficient funds to make these accelerated payments. Any subsequent replacement of our revolving credit facility or any new indebtedness could have similar or greater restrictions.

We may have difficulty maintaining compliance with the covenants and ratios required under our Credit Agreement, which currently include covenants to maintain certain levels of excess available borrowings and generate minimum amounts of consolidated EBITDA on a quarterly basis. Failure to maintain compliance with these financial covenants could adversely affect our operations, financial condition, and our ability to pay distributions to our unitholders.

We depend on our Credit Agreement for future capital needs and to fund our operations and capital expenditures, as necessary. We are required to comply with certain financial covenants and ratios under the Credit Agreement. Our ability to comply with these restrictions and covenants in the future is uncertain and will be affected by the levels of cash flow from our operations and events or circumstances beyond our control, including events and circumstances that may stem from the condition of financial markets and commodity price levels. On November 18, 2015, we entered into the Second Amendment to the Credit Agreement that, among other things, forgoes the application of the total leverage ratio and interest coverage ratio covenants until the earlier of June 30, 2018 or such time as our total leverage ratio is less than 3.5 to 1.00 as of the end of any two consecutive fiscal quarters. Prior to our required compliance with these ratios, we will be subject to additional covenants and restrictions including, among other things, covenants to maintain certain levels of excess available borrowings under the Credit Agreement and to generate a certain minimum amount of consolidated EBITDA. At December 31, 2015, we were in compliance with our loan covenants.

Our failure to comply with any of the covenants of the Credit Agreement could result in a default, which could cause all of our existing indebtedness to become immediately due and payable. In the event that we are unable to access sufficient capital to fund our business and planned capital expenditures, we may be required to curtail our acquisitions, strategic growth projects, portions of our current operations and other activities. A lack of capital could result in a decrease in the operations of our sand and fuel segments, subject us to claims of breach under customer and supplier contracts and may force us to sell some of our assets on an untimely or unfavorable basis, each of which could adversely affect our results of operations, financial condition and ability to pay distributions to our unitholders.

If we are unable to generate enough cash flow from operations to service our indebtedness or are unable to use future borrowings to refinance our indebtedness or fund other capital needs, we may have to undertake alternative financing plans, which may have onerous terms or may be unavailable.

We cannot assure you that our business will generate sufficient cash flow from operations to service our outstanding indebtedness, or that future borrowings will be available to us in an amount sufficient to enable us to pay our indebtedness or to fund our other capital needs. If we do not generate sufficient cash flow from operations to satisfy our debt obligations, we may have to undertake alternative financing plans, such as:

- refinancing or restructuring all or a portion of our debt;
- obtaining alternative financing;
- selling assets;
- reducing or delaying capital investments;
- seeking to raise additional capital; or
- revising or delaying our strategic plans.

However, we cannot assure you that we would be able to implement alternative financing plans, if necessary, on commercially reasonable terms or at all, or that undertaking alternative financing plans, if necessary, would allow us to meet our debt obligations and capital requirements or that these actions would be permitted under the terms of our various debt instruments.

Our inability to generate sufficient cash flow to satisfy our debt obligations or to obtain alternative financing could materially and adversely affect our business, financial condition, results of operations, cash flows, and prospects. Any failure to make scheduled payments of interest and principal on our outstanding indebtedness would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness on acceptable terms. Further, if for any reason we are unable to meet our debt service and repayment obligations, we would be in default under the terms of the agreements governing our debt, which would allow our creditors at that time to declare all outstanding indebtedness to be due and payable (which would in turn trigger cross-acceleration or cross-default rights between the relevant agreements), the lenders under our Credit Agreement could terminate their commitments to loan money, and the lenders could foreclose against our assets securing their borrowings and we could be forced into bankruptcy or liquidation. If the amounts outstanding under our Credit Agreement or any of our other indebtedness were to be accelerated, we cannot assure you that our assets would be sufficient to repay in full the money owed to the lenders or to our other debt holders.

Despite our current level of indebtedness, we may still be able to incur substantially more debt. This could further exacerbate the risks associated with our current indebtedness.

We and our subsidiaries may be able to incur substantial additional indebtedness in the future, subject to certain limitations, including under our Credit Agreement. If new debt is added to our current debt levels, the related risks that we now face could increase. Our level of indebtedness could, for instance, prevent us from engaging in transactions that might otherwise be beneficial to us or from making desirable capital expenditures. This could put us at a competitive disadvantage relative to other less leveraged competitors that have more cash flow to devote to their operations. In addition, the incurrence of additional indebtedness could make it more difficult to satisfy our existing financial obligations.

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

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

Additionally, our ability to hire, train and retain qualified personnel will continue to be important and will become more challenging as we grow and if energy industry market conditions continue to be positive. When general industry conditions are good, the

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competition for experienced operational personnel increases as other energy and manufacturing companies' personnel needs increase. Our ability to grow or even to continue our current level of service to our current customers will be adversely impacted if we are unable to successfully hire, train and retain these important personnel.

Inaccuracies in our estimates of mineral reserves could result in lower than expected sales and higher than expected costs.

We base our mineral reserve estimates on engineering, economic, and geological data assembled and analyzed by our engineers and geologists, which are reviewed by outside firms. However, sand reserve estimates are necessarily imprecise and depend to some extent on statistical inferences drawn from available drilling data, which may prove unreliable. There are numerous uncertainties inherent in estimating quantities and qualities of mineral reserves and in estimating costs to mine recoverable reserves, including many factors beyond our control. Estimates of recoverable mineral reserves necessarily depend on a number of factors and assumptions, all of which may vary considerably from actual results, such as:

- geological and mining conditions and/or effects from prior mining that may not be fully identified by available data or that may differ from experience;
- assumptions concerning future prices of frac sand products, operating costs, mining technology improvements, development costs and reclamation costs; and
- assumptions concerning future effects of regulation, including our ability to obtain required permits and the imposition of taxes by governmental agencies.

Any inaccuracy in our estimates related to our mineral reserves could result in lower than expected sales and higher than expected costs and have an adverse effect on our cash available for distribution.

Our Sand operations are dependent on our rights and ability to mine our properties and on our having renewed or received the required permits and approvals from governmental authorities and other third parties.

We hold numerous governmental, environmental, mining, and other permits, water rights and approvals authorizing operations at each of our Sand facilities. A decision by a governmental agency or other third party to deny or delay issuing a new or renewed permit, water right or approval, or to revoke or substantially modify an existing permit, water right or approval, could have a material adverse effect on our ability to continue operations at the affected facility. Expansion of our existing operations is also predicated on securing the necessary environmental or other permits, water rights or approvals, which we may not receive in a timely manner or at all.

We are subject to compliance with stringent environmental laws and regulations that may expose us to substantial costs and liabilities.

Our sand and fuel processing, fuel terminal, and mining operations are subject to increasingly stringent and complex federal, state and local environmental laws, regulations and standards governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws, regulations and standards impose numerous obligations that are applicable to our operations, including the acquisition of permits to conduct regulated activities; the incurrence of significant capital expenditures to limit or prevent releases of materials from our processors, terminals, and related facilities; and the imposition of remedial actions or other liabilities for pollution conditions caused by our operations or attributable to former operations. Numerous governmental authorities, such as the EPA, and similar state agencies, have the power to enforce compliance with these laws, regulations and standards and the permits issued under them, often requiring difficult and costly actions.

Failure to comply with environmental laws, regulations, standards, permits, and orders may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, and the issuance of injunctions limiting or preventing some or all of our operations. Certain environmental laws impose strict liability for the remediation of spills and releases of oil and hazardous substances that could subject us to liability without regard to whether we were negligent or at fault. In addition, changes in environmental laws and regulations occur frequently, and any such changes that result in more stringent and costly waste handling, storage, transport, disposal or remediation requirements with respect to our operations or more stringent or costly well drilling, construction, completion or water management activities with respect to our customers' operations could adversely affect our operations, financial results and cash available for distribution.

There is inherent risk of incurring significant environmental costs and liabilities in the operation of our facilities due to our handling of petroleum hydrocarbons, biodiesel, ethanol and wastes, air emissions and water discharges related to our operations, and historical operations and waste disposal practices by prior owners and operators. We currently own or operate properties that for many years have been used for industrial activities, including processing or terminal storage operations. Petroleum hydrocarbons, hazardous substances, or wastes have been released on or under the properties owned or operated by us. Joint and several strict liability may be incurred in connection with such releases of petroleum hydrocarbons and wastes on, under or from our properties and facilities. Private parties, including the owners or operators of properties adjacent to our operations and facilities where our petroleum hydrocarbons or wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance

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as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. We may not be able to recover some or any of these costs from insurance or other sources of indemnity.

Increasingly stringent environmental laws and regulations, unanticipated remediation obligations or emissions control expenditures and claims for penalties or damages could result in substantial costs and liabilities, and our ability to make distributions to our unitholders could suffer as a result. Neither the owners of our general partner nor their affiliates will indemnify us for any environmental liabilities, including those arising from non-compliance or pollution, that may be discovered at, on or under, or arise from, our operations or assets. As such, we can expect no economic assistance from any of them in the event that we are required to make expenditures to investigate, correct or remediate any petroleum hydrocarbons, hazardous substances, wastes or other materials. Please see "Environmental and Occupational Health and Safety Regulations" for more detail regarding the environmental and occupational health and safety rules that impact our operations.

The effect of the renewable fuel standard program in the Energy Independence and Security Act of 2007 is uncertain.

The domestic market for biodiesel is largely dictated by federal mandates for blending renewable fuels with gasoline and diesel. In December 2015, the EPA published the final levels for biomass-based diesel under the RFS in the Energy Independence and Security Act of 2007 for 2014, 2015, 2016 and 2017. The final levels for 2014, 2015, 2016 and 2017 are 1.63, 1.73, 1.90, and 2.00 billion gallons, respectively. Future demand will be largely dependent upon the capacity available to meet the RFS, and the economic incentives to blend based upon the relative value of traditional diesel versus biomass-based diesel. Any significant increase in production capacity beyond the RFS level could have a negative impact on biodiesel prices. An administrative or court-ordered reduction or waiver of the RFS mandate could also negatively affect biodiesel prices and our future performance.

We may be unable to sell some of our transmix-derived diesel fuel in the off-road markets because it may contain sulfur concentrations above levels allowed by EPA regulations.

In mid-2006, the EPA promulgated regulations requiring a reduction in the sulfur content of diesel fuel. Using a phased-in approach through 2014, these regulations require that the maximum allowable sulfur content of diesel fuels used in a variety of off-road applications, excluding locomotive and marine uses, be reduced to 15 ppm (referred to as "ultra-low sulfur diesel"). The diesel fuel produced from our transmix operations is sold for use in off-road applications and is subject to these phased-in regulations, except for diesel fuel used in locomotive and marine applications outside of the Northeast and Mid-Atlantic regions of the United States. Because a portion of our transmix consists of jet fuel, which currently is not subject to EPA regulations limiting its maximum sulfur content, the diesel fuel produced from such transmix may exceed the 15 ppm level. In the event that diesel fuel produced from transmix exceeds the 15 ppm level, we would be prohibited from marketing this fuel for any uses other than locomotive or marine outside of the Northeast and Mid-Atlantic regions. If this were to occur, we would have to find new customers for our transmix diesel, find economic means of reducing sulfur levels or stop sourcing higher sulfur transmix that is mixed with jet fuel. Further, changes in emissions regulations for locomotives will likely mean only marine customers will be able to use fuel that exceeds the 15 ppm level at some time between 2015 and 2020. A number of our rail customers have indicated to us that they are planning to accept only diesel fuel with less than 15 ppm as they phase in a new generation of locomotives. There can be no assurance that we would be able to find sufficient marine customers or economic means for reducing sulfur levels without an adverse effect on our financial condition, results of operations, or ability to make distributions to our unitholders.

Our sales of petroleum products, and any related hedging activities, expose us to potential regulatory risks.

The Federal Trade Commission and the Commodity Futures Trading Commission hold statutory authority to regulate conduct in certain physical energy commodities markets and in markets for energy commodities futures, options on futures and swaps that may be relevant to our business. These agencies have imposed broad regulations prohibiting fraud and manipulation in the markets over which they have statutory authority. With regard to our physical sales of fuel products, and any related hedging activities, we may be required to observe the market-related regulations enforced by these agencies, which hold substantial enforcement authority. Failure to comply with such regulations, as interpreted and enforced, could materially and adversely affect our financial condition, or results of operations.

Government action on climate change could result in increased compliance costs for us and our customers.

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

Independent of Congress, the EPA is beginning to adopt regulations controlling GHG emissions under its existing authority under the CAA. For example, on December 15, 2009, the EPA officially published its findings that emissions of carbon dioxide, methane

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and other GHGs present an endangerment to human health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHGs under existing provisions of the CAA. In 2009, the EPA adopted rules regarding regulation of GHG emissions from motor vehicles. In addition, on September 22, 2009, the EPA issued a final rule requiring the reporting of GHG emissions in the United States beginning in 2011 for emissions occurring in 2010 from specified large GHG emission sources. On November 30, 2010, the EPA published a final rule expanding its existing GHG emissions reporting rule for certain petroleum and natural gas facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year, which was again amended in October 2015 to cover additional oil and natural gas operations. The rule, which went into effect on December 30, 2010, requires reporting of GHG emissions by such regulated facilities to the EPA by September 2012 for emissions during 2011 and annually thereafter. In 2010, the EPA also issued a final rule, known as the “Tailoring Rule,” that makes certain large stationary sources and modification projects subject to permitting requirements for GHG emissions under the CAA. Several of the EPA's GHG rules are being challenged in court and, depending on the outcome of these proceedings, such rules may be modified or rescinded or the EPA could develop new rules.

Although it is not currently possible to predict how any such proposed or future GHG legislation or regulation by Congress, the EPA, the states or multi-state regions will impact our business, any legislation or regulation of GHG emissions that may be imposed in areas in which we conduct business could result in increased compliance costs or additional operating restrictions or reduced demand for our services, and could have a material adverse effect on our business, financial condition and results of operations.

Further, in December 2015, over 190 countries, including the United States, reached an agreement to reduce global greenhouse gas emissions. To the extent the United States or any other country implement this agreement or impose other climate change regulations on the oil and gas industry, it could have an adverse direct or indirect effect on our business.

Mine closures entail substantial costs, and if we close one or more of our mines sooner than anticipated, our results of operations may be adversely affected.

We base our assumptions regarding the life of our mines on detailed studies that we perform from time to time, but our studies and assumptions do not always prove to be accurate. If we close any of our mines sooner than expected, sales will decline unless we are able to increase production at any of our other mines, which may not be possible. Applicable statutes and regulations require that mining property be reclaimed following a mine closure in accordance with specified standards and an approved reclamation plan. The plan addresses matters such as decommissioning and removal of facilities and equipment, re-grading, prevention of erosion and other forms of water pollution, re-vegetation and post-mining monitoring and land use. We may be required to post a surety bond or other form of financial assurance equal to the cost of reclamation as set forth in the approved reclamation plan. The establishment of the final mine closure reclamation liability is based on permit requirements and requires various estimates and assumptions, principally associated with reclamation costs and production levels. If our accruals for expected reclamation and other costs associated with mine closures for which we will be responsible were later determined to be insufficient, or if we were required to expedite the timing for performance of mine closure activities as compared to estimated timelines, our business, results of operations and financial condition could be adversely affected.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing and the potential for related regulatory action or litigation could result in increased costs and additional operating restrictions or delays for our customers, which could negatively impact our business, financial condition and results of operations and cash flows.

A significant portion of our business supplies frac sand to oil and natural gas industry customers performing hydraulic fracturing activities. Increased regulation of hydraulic fracturing may adversely impact our business, financial condition, and results of operations.

Hydraulic fracturing involves the injection of water, sand, and chemicals under pressure into the formation to stimulate gas production. Legislation to amend the Safe Drinking Water Act (the “SDWA”) to repeal the exemption for hydraulic fracturing from the definition of “underground injection” and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, were proposed in recent sessions of Congress and Congress continues to consider legislation to amend the SDWA. We cannot predict whether any such legislation will ever be enacted and, if so, what its provisions would be. Scrutiny of hydraulic fracturing activities continues in other ways, with the EPA having commenced a multi-year study of the potential environmental impacts of hydraulic fracturing, with a final draft of the report was released in 2015 for peer review and comment, and the U.S. Department of Energy having released a series of recommendations for improving the safety of the process in 2011. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms. Further, the EPA and the U.S. Department of the Interior (the “DOI”) have proposed and adopted new regulations for certain aspects of the process. For example, the EPA proposed effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing. The DOI adopted rules that initial results released in December of 2012 and final results expected to be available by 2014 and, more recently, the EPA has announced that it will

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develop effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities by 2014. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior (the “DOI”), are evaluating various other aspects of hydraulic fracturing, with the DOI announcing draft proposed rules on May 4, 2012 that, if adopted, would require disclosure of chemicals used in hydraulic fracturing activities upon federal and Indian lands and also would strengthen standards for well-bore integrity and the management of fluids that return to the surface during and after fracturing operations on federal and Indian lands (although implementation of this rule has been stayed pending the resolution of legal challenges) but subsequently announcing on January 18, 2013, that it will issue a revised draft proposal in replacement of the May 2012 draft in 2013. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms. The EPA also has announced that it believes hydraulic fracturing using fluids containing diesel fuel can be regulated under the SDWA notwithstanding the SDWA's general exemption for hydraulic fracturing and, more recently on May 4, 2012, the EPA issued draft guidance for SDWA permits issued to oil and natural gas exploration and production operators using diesel fuel during hydraulic fracturing.

In addition, various state, local and foreign governments have implemented, or are considering, increased regulatory oversight of hydraulic fracturing through additional permitting requirements, operational restrictions, disclosure requirements and temporary or permanent bans on hydraulic fracturing in certain areas, such as environmentally sensitive watersheds. For example, many states - including the major oil and gas producing states of North Dakota, Ohio, Oklahoma, Pennsylvania, Texas, and West Virginia - have imposed disclosure requirements on hydraulic fracturing well owners and operators. The availability of public information regarding the constituents of hydraulic fracturing fluids could make it easier for third parties opposing the hydraulic fracturing process to initiate individual or class action legal proceedings based on allegations that specific chemicals used in the hydraulic fracturing process could adversely affect groundwater and drinking water supplies or otherwise cause harm to human health or the environment. Moreover, disclosure to third parties or to the public, even if inadvertent, of our customers' proprietary chemical formulas could diminish the value of those formulas and result in competitive harm to our customers, which could indirectly impact our business, financial condition and results of operations. The adoption of new laws or regulations at the federal, state, local or foreign levels imposing reporting obligations on, or otherwise limiting or delaying, the hydraulic fracturing process could make it more difficult to complete natural gas wells in shale formations, increase our customers' costs of compliance and doing business and otherwise adversely affect the hydraulic fracturing services they perform, which could negatively impact demand for our frac sand products. In addition, heightened political, regulatory, and public scrutiny of hydraulic fracturing practices could potentially expose us or our customers to increased legal and regulatory proceedings, and any such proceedings could be time-consuming, costly or result in substantial legal liability or significant reputational harm. Any such developments could have a material adverse effect on our business, financial condition, and results of operations, whether directly or indirectly. For example, we could be directly by affected adverse litigation involving us, or indirectly affected if the cost of compliance limits the ability of our customers to operate in the geographic areas we serve.

We are subject to the Federal Mine Safety and Health Act of 1977, which imposes stringent health and safety standards on numerous aspects of our operations.

Our operations are subject to the Federal Mine Safety and Health Act of 1977, as amended by the Mine Improvement and New Emergency Response Act of 2006, which imposes stringent health and safety standards on numerous aspects of mineral extraction and processing operations, including the training of personnel, operating procedures and operating equipment. We are also subject to standards imposed by MSHA and other federal and state agencies relating to workplace exposure to crystalline silica. Our failure to comply with such standards, or changes in such standards or the interpretation or enforcement thereof, could have a material adverse effect on our business and financial condition or otherwise impose significant restrictions on our ability to conduct mineral extraction and processing operations.

We and our customers are subject to other extensive regulations, including licensing, protection of plant and wildlife endangered and threatened species, and reclamation regulation, that impose, and will continue to impose, significant costs and liabilities. In addition, future regulations, or more stringent enforcement of existing regulations, could increase those costs and liabilities, which could adversely affect our results of operations.

In addition to the regulatory matters described above, we and our customers are subject to extensive governmental regulation on matters such as permitting and licensing requirements, plant and wildlife threatened and endangered species protection, jurisdictional wetlands protection, reclamation and restoration activities at mining properties after mining is completed, the discharge of materials into the environment and the effects that mining and hydraulic fracturing have on groundwater quality and availability. Our future success depends, among other things, on the quantity of our frac sand and other mineral deposits and our ability to extract these deposits profitably, and our customers being able to operate their businesses as they currently do.

In order to obtain permits and renewals of permits in the future, we may be required to prepare and present data to governmental authorities pertaining to the potential adverse impact that any proposed mining and processing activities may have on the environment, individually or in the aggregate, including on public lands. Certain approval procedures may require preparation of archaeological surveys, endangered species studies and other studies to assess the environmental impact of new sites or the expansion of existing sites. Compliance with these regulatory requirements is expensive and significantly lengthens the time needed to develop a site. Finally, obtaining or renewing required permits is sometimes delayed or prevented due to community opposition and other factors beyond our control. The denial of a permit essential to our operations or the imposition of conditions with which it is not practicable or feasible to comply could impair or prevent our ability to develop or expand a site. Significant opposition to a permit by neighboring property owners, members of the public or non-governmental organizations, or other third parties or delay in the environmental review and permitting process also could impair or delay our ability to develop or expand a site. New legal requirements, including those related to the protection of the environment, could be adopted that could materially adversely affect our mining operations (including our ability to extract or the pace of extraction of mineral deposits), our cost structure or our customers' ability to use our frac sand products. Such current or future regulations could have a material adverse effect on our business and we may not be able to obtain or renew permits in the future.

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

The long-term impact of terrorist attacks, such as the attacks that occurred on September 11, 2001, and the magnitude of the threat of future terrorist attacks on the energy industry in general and on us in particular are not known at this time. Uncertainty surrounding hostilities in the Middle East or other sustained military campaigns may affect our operations in unpredictable ways, including disruptions of markets for frac sand and refined products and the possibility that infrastructure facilities and pipelines could be direct targets of, or indirect casualties of, an act of terror. Changes in the insurance markets attributable to terrorist attacks may make certain types of insurance more difficult for us to obtain. Moreover, the insurance that may be available to us may be significantly more expensive than our existing insurance coverage. Instability in the financial markets as a result of terrorism or war could also affect our ability to raise capital.

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 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.

Risks Inherent in an Investment in Us

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

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management's decisions regarding our business. Unitholders have no right on an annual or ongoing basis to elect our general partner or its board of directors. Insight Equity is the majority owner of our general partner and has the right to appoint our general partner's entire board of directors, including our independent directors. If the unitholders are dissatisfied with the performance of our general partner, they have little ability to remove our general partner. As a result of these limitations, the price at which the common units trade may be diminished because of the absence or reduction of a takeover premium in the trading price. 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.

Insight Equity owns the majority of and controls our general partner, which has sole responsibility for conducting our business and managing our operations. Our general partner and its affiliates, including Insight Equity, have conflicts of interest with us and limited duties, and they may favor their own interests to the detriment of us and our common unitholders.

Insight Equity owns the majority of and controls our general partner and appoints all of the officers and directors of our general partner, some of whom are officers and directors of Insight Equity. Although our general partner has a duty to manage us in a manner that is beneficial to us and our unitholders, the directors and officers of our general partner have a fiduciary duty to manage

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our general partner in a manner that is beneficial to its owners. Conflicts of interest may arise between Insight Equity and our general partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of Insight Equity and the other owners of our general partner over our interests and the interests of our common unitholders. These conflicts include the following situations, among others:

- neither our partnership agreement nor any other agreement requires Insight Equity to pursue a business strategy that favors us or utilizes our assets or dictates what markets to pursue or grow;
- our general partner is allowed to take into account the interests of parties other than us, such as Insight Equity, in resolving conflicts of interest;
- our partnership agreement replaces the fiduciary duties that would otherwise be owed by our general partner with contractual standards governing its duties, limits our general partner's liabilities and restricts the remedies available to our unitholders for actions that, without these limitations, might constitute breaches of its fiduciary duty;
- 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 decision was in the best interests of our partnership, and, except as specifically provided by our partnership agreement, 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;
- except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval;
- our general partner determines the amount and timing of asset purchases and sales, capital expenditures, borrowings, issuances of additional partnership securities and the creation, reduction or increase of reserves, each of which can affect the amount of cash that is distributed to our unitholders;
- our general partner determines which of the costs it incurs on our behalf are reimbursable by us;
- our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or from entering into additional contractual arrangements with any of these entities on our behalf;
- our general partner intends to limit its liability regarding our 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 they own more than 80% of the common units;
- our general partner controls the enforcement of its and its affiliates' obligations to us; and
- our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

Our general partner limits its liability regarding our obligations.

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

Our 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 replace 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, which means that a court will enforce the reasonable expectations of the partners where the language in the partnership agreement does not provide for a clear course of action. 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 business opportunities among us and its affiliates;

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

Our common unitholders have agreed to become bound by the provisions in the partnership agreement, including the provisions discussed above.

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

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

- provides that whenever our general partner 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 it subjectively believed that the decision was in the best interest of our partnership, and except as specifically provided by our partnership agreement, 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 such decisions are made in good faith;
- provides that our general partner and its officers and directors will not be liable for monetary damages to us, our limited partners or their assignees resulting from any act or omission unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our general partner or its officers and directors, as the case may be, acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was unlawful; and
- provides that our general partner will not be in breach of its obligations under our partnership agreement (including any duties to us or our unitholders) if a transaction with an affiliate or the resolution of a conflict of interest is:
- approved by the conflicts committee of the board of directors of our general partner, although our general partner is not obligated to seek such approval;
- approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner or any of its affiliates;
- determined by the board of directors of our general partner to be on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or
- determined by the board of directors of our general partner to be “fair and reasonable” to us, taking into account the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to us.

In connection with a situation involving a transaction with an affiliate or a conflict of interest, any determination by our general partner must be made in good faith. If an affiliate transaction or the resolution of a conflict of interest is not approved by our common unitholders or the conflicts committee and the board of directors of our general partner determines that the resolution or course of action taken with respect to the affiliate transaction or conflict of interest satisfies either of the standards set forth in bullets three and four above, then it will be presumed that, in making its decision, the board of directors acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the partnership, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption. In this context, members of the board of directors of our general partner will be conclusively deemed to have acted in good faith if it subjectively believed that either of the standards set forth in bullets three and four above was satisfied.

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

Unitholders' voting rights are further restricted by a provision of our partnership agreement providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our general partner, its affiliates, their direct transferees and their indirect transferees approved by our general partner (which approval may be granted in its sole discretion) and persons who acquired such units with the prior approval of our general partner, cannot vote on any matter.

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

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, our partnership agreement does not restrict the ability of Insight Equity to transfer all or a portion of its ownership interest in our general partner to a third party. The new owner of our general partner would then be in a position to replace the board of directors and officers of our general partner with its own designees and thereby exert significant control over the decisions made by the board of directors and officers.

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

Like all equity investments, an investment in our common units is subject to certain risks. In exchange for accepting these risks, investors may expect to receive a higher rate of return than would otherwise be obtainable from lower-risk investments. Accordingly, as interest rates rise, the ability of investors to obtain higher risk-adjusted rates of return by purchasing government-backed debt securities may cause a corresponding decline in demand for riskier investments generally, including yield-based equity investments such as publicly traded partnership interests. Reduced demand for our common units resulting from investors seeking other more favorable investment opportunities may cause the trading price of our common units to decline.

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

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

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

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

If at any time our general partner and its affiliates own more than 80% of the common units, our general partner will have the right, which it may assign to any of its affiliates or to us, but not the obligation, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price that is not less than their then-current market price, as calculated pursuant to the terms of our partnership agreement. As a result, you may be required to sell your common units at an undesirable time or price and may not receive any return or a negative return on your investment. You may also incur a tax liability upon a sale of your units.

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

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. Our partnership is organized under Delaware law, and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. You could be liable for any and all of our obligations as if you were a general partner if a court or government agency were to determine that:

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

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

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

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

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

If we fail to maintain an effective system of internal controls, we may not be able to accurately report our financial results or prevent fraud. As a result, current and potential unitholders could lose confidence in our financial reporting, which would harm our business and the trading price of our units.

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud, and operate successfully as a public company. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results would be harmed. We cannot be certain that we will be able to maintain adequate controls over our financial processes and reporting in the future or that we will be able to comply with our obligations under Section 404 of the Sarbanes Oxley Act of 2002. Any failure to maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our units.

Tax Risks to Common Unitholders

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

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state and local income tax at varying rates. Distributions would generally be taxed again as corporate dividends (to the extent of our current and accumulated earnings and profits), and no income, gains, losses, deductions, or credits would flow through to you. Because a tax would be imposed upon us as a corporation, our cash available for distribution to you 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.

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

Changes in current state law may subject us to additional entity-level taxation by individual states. Because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of any such taxes may substantially reduce the cash available for distribution to you and, therefore, negatively impact the value of and investment in our common units.

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

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative, or judicial interpretation at any time. For example, from time to time, the U.S. government considers substantive changes to the existing federal income tax laws that affect publicly traded partnerships, including the elimination of the qualifying income exception upon which we rely for our treatment as a partnership for federal income tax purposes.

Moreover, on May 6, 2015, the U.S. Department of Treasury and the IRS published proposed regulations (the "Proposed Regulations") that would affect the qualifying income exception upon which we rely for partnership tax treatment by providing industry-specific guidance regarding whether income earned from certain activities will constitute qualifying income. Although the Proposed Regulations adopt a narrow interpretation of the activities that generate qualifying income, we believe the income that we treat as qualifying income satisfies the requirements for qualifying income under the Proposed Regulations.

Any modification to the 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 exception for us to be treated as a partnership for federal income tax purposes.

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We are unable to predict whether any of these changes or other proposals 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 is taxable to them for federal income tax purposes even if they do not receive any cash distributions from us.

Because a unitholder is treated as a partner to whom we allocate taxable income which could be different in amount than the cash we distribute, a unitholder's allocable share of our taxable income is 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. For example, a gain on the sale of any of our assets may result in a unitholder being allocated taxable income without receiving a corresponding cash distribution 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 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.

The IRS has made no determination with respect to our treatment as a partnership for 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 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 because the costs will reduce our cash available for distribution.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after December 31, 2017, it 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.

We have a subsidiary that is treated as a corporation for federal income tax purposes and subject to corporate-level income taxes.

Even though we (as a partnership for U.S. federal income tax purposes) are not subject to federal income tax, some of our operations are currently conducted through a subsidiary that is organized as a corporation for federal income tax purposes. The taxable income, if any, of a subsidiary that is treated as a corporation for U.S. federal income tax purposes, is subject to corporate-level federal income taxes, which may reduce the cash available for distribution to us and, in turn, to our unitholders. If the IRS or other state or local jurisdictions were to successfully assert that this corporation has more tax liability than we anticipate or legislation was enacted that increased the corporate tax rate, the cash available for distribution could be further reduced. The income tax return filings positions taken by this corporate subsidiary require significant judgment, use of estimates, and the interpretation and application of complex tax laws. Significant judgment is also required in assessing the timing and amounts of deductible and taxable items. Despite our belief that the income tax return positions taken by this subsidiary are fully supportable, certain positions may be successfully challenged by the IRS, state or local jurisdictions.

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

If you sell your common units, you will recognize a gain or loss for federal income tax purposes equal to the difference between the amount realized and your tax basis in those common units. Because distributions in excess of your allocable share of our net taxable income decrease your tax basis in your common units, the amount, if any, of such prior excess distributions with respect to the common units you sell will, in effect, become taxable income to you if you sell such common units at a price greater than your tax basis in those common units, even if the price you receive is less than your original cost. Furthermore, a substantial portion of the amount realized on any sale of your common units, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation and depletion recapture. In addition, because the amount realized

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includes a unitholder's share of our nonrecourse liabilities, if you sell your common units, you may incur a tax liability in excess of the amount of cash you receive from the sale.

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

Investment in common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (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, is unrelated business taxable income and is taxable to them.

Distributions to non-U.S. persons are reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons are required to file federal income tax returns and pay tax on their share of our taxable income. If you are a tax-exempt entity or a non-U.S. person, you should consult a tax advisor before investing in our common units.

We 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 you. It also could affect the timing of these tax benefits or the amount of gain or loss from your sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to your tax returns.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common 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 aspects of our proration method, and, if successful, we would be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first business 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 recently 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 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 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 deductions 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. Our unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to consult a tax advisor to discuss whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from loaning their common units.

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

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

Our technical termination would, 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 federal income tax purposes, but instead we would be treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred. The IRS has announced a publicly traded partnership technical termination relief program whereby, if a publicly traded partnership that technically terminated requests publicly traded partnership technical

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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 in which the termination occurs, notwithstanding two partnership tax years.

We may become a resident of Canada and be required to pay tax in Canada on our worldwide income, which could reduce our earnings, and unitholders could then become taxable in Canada in respect of their ownership of our common units.

Under the Income Tax Act (Canada), or the Canadian Tax Act, a company that is resident in Canada is subject to tax in Canada on its worldwide income, and unitholders of a company resident in Canada may be subject to Canadian capital gains tax on a disposition of its units and to Canadian withholding tax on dividends paid in respect of such units.

Under Canadian law, our place of residence would generally be determined based on the location where our central management and control is exercised. Although our central management and control is currently exercised in the United States and we intend to continue to conduct our affairs and operate in such a manner, if we were nonetheless to be considered a Canadian resident for purposes of the Canadian Tax Act, our worldwide income would become subject to Canadian income tax under the Canadian Tax Act. Further, unitholders who are non-residents of Canada may become subject under the Canadian Tax Act to tax in Canada on any gains realized on the disposition of our units and would become subject to Canadian withholding tax on dividends paid or deemed to be paid by us, subject to any relief that may be available under a tax treaty or convention.

As a result of investing in our common units, you 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 federal income taxes, our unitholders could be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or control property now or in the future, even if they do not live in any of those jurisdictions. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We currently 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 your responsibility to file all federal, state and local tax returns. Please consult your tax advisor.

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ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Please see Item 1. Business above for descriptions and discussion of our segments' principal properties:

- Mineral Reserves;
- Mines and Wet Plants;
- Dry Plant Facilities;
- Transportation Logistics and Infrastructure;
- Dallas-Fort Worth Facility; and
- Birmingham Facility.

In addition to these properties used in operations, we lease office space for subsidiary and corporate administrative staff:

- Sand segment - Fort. Worth, Texas;
- Fuel Segment - Birmingham, Alabama and Arlington, Texas; and
- Corporate - Southlake, Texas.

ITEM 3. LEGAL PROCEEDINGS

Although we are, from time to time, involved in litigation and claims arising out of our operations in the normal course of business, we do not believe that we are a party to any litigation that could have a material adverse impact on our financial condition or results of operations. We are not aware of any undisclosed significant legal or governmental proceedings against us, or contemplated to be brought against us. We maintain such insurance policies with insurers in amounts and with coverage and deductibles as our general partner believes are reasonable and prudent. However, we cannot assure you that this insurance will be adequate to protect us from all material expenses related to potential future claims for personal and property damage or that these levels of insurance will be available in the future at economical prices.

Environmental Matter

On November 21, 2013, the EPA issued a General Notice Letter and Information Request (“Notice”) under Section 104(e) of CERCLA to one of our subsidiaries operating within the Fuel segment. The Notice provides that the subsidiary may have incurred liability with respect to the Reef Environmental site in Alabama, and requested certain information in accordance with Section 107(a) of CERCLA. We timely responded to the Notice. At this time, no specific claim for cost recovery has been made by the EPA (or any other potentially responsible party) against us. There is uncertainty relating to our share of environmental remediation liability, if any, because our allocable share of wastewater is unknown and the total remediation cost is also unknown. Consequently, management is unable to estimate the possible loss or range of loss, if any. We have not recorded a loss contingency accrual in our financial statements. In the opinion of management, the outcome of such matters will not have a material adverse effect on our financial position, liquidity, or results of operations.

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ITEM 4. MINE SAFETY DISCLOSURES

We adhere to a strict occupational health program aimed at controlling exposure to silica dust, which includes dust sampling, a respiratory protection program, medical surveillance, training, and other components. We designed our safety program to ensure compliance with the standards of our Occupational Health and Safety Manual and U.S. Federal Mine Safety and Health Administration ("MSHA") regulations. For both health and safety issues, extensive training is provided to employees. We have organized safety committees at our plants made up of both salaried and hourly employees. We perform annual internal health and safety audits and conduct semi-annual crisis management drills to test our abilities to respond to various situations. Our corporate health and safety department administers the health and safety programs with the assistance of plant environmental, health and safety coordinators.

All of our production facilities are classified as mines and are subject to regulation by MSHA under the Federal Mine Safety and Health Act of 1977 (the "Mine Act"). MSHA inspects our mines on a regular basis and issues various citations and orders when it believes a violation has occurred under the Mine Act. Following passage of The Mine Improvement and New Emergency Response Act of 2006, MSHA significantly increased the numbers of citations and orders charged against mining operations. The dollar penalties assessed for citations issued has also increased in recent years. Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17 CFR 229.104) is included in Exhibit 95.1 to this Annual Report on Form 10-K.

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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 "EMES" and began trading on May 14, 2013 on a "when-issued" basis. Prior to May 14, 2013, our common units were not listed on any exchange or traded in any public market. On February 22, 2016, the closing market price for the common units was $3.92 per unit. As of February 22, 2016, there were 24,121,222 common units outstanding. There were approximately 21,209 record holders of common units on December 31, 2015. This number does not include unitholders whose units are held in trust by other entities. The actual number of unitholders is greater than the number of holders of record.

The following table sets forth, for each period indicated, the high and low sales prices per common unit, as reported on the NYSE, and the cash distributions declared and paid per common unit during each quarter since our initial public offering:

Quarter Ended	High Price	Low Price	Distributions Declared Per Unit
March 31, 2014	$62.69	$42.28	$1.00
June 30, 2014	$116.99	$59.60	$1.13
September 30, 2014	$145.72	$101.11	$1.17
December 31, 2014	$118.71	$39.90	$1.38
March 31, 2015	$63.00	$41.13	$1.41
June 30, 2015	$52.75	$34.16	$1.00
September 30, 2015	$37.57	$6.10	$0.67
December 31, 2015	$9.25	$3.78	$—

Cash Distribution Policy

Our partnership agreement requires that we distribute all of our available cash quarterly, as defined by the Board. The actual distributions we declare are subject to our operating performance, prevailing market conditions, the impact of unforeseen events, and the approval of our Board of Directors in a manner consistent with our distribution policy. Under our Cash Distribution Policy, available cash is generally defined to mean, for each quarter, the amount of cash generated during the quarter that the Board determines is available for distribution to unitholders. The Board may consider the advice of management, the amount of cash needed for maintenance capital expenditures, debt service and other of our contractual obligations and any future operating or capital needs that the Board deems necessary or appropriate. The Board may also consider our ability to comply with the financial tests and covenants contained in our credit agreement and any other debt instrument under which we have similar obligations. The Board may establish cash reserves for the prudent conduct of our business.

There is no guarantee that we will distribute quarterly cash distributions to our unitholders. Our cash distribution policy is subject to restrictions on cash distributions under our credit facility. Specifically, our credit facility contains financial tests and covenants that we must satisfy before quarterly cash distributions can be paid. In addition, our ability to pay quarterly cash distributions will be restricted if an event of default has occurred under our credit facility. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation — Liquidity and Capital Resources — Credit Facility.

Issuer Purchases of Equity Securities

None.

Performance Graph

The following graph compares the performance of our common units since the IPO to the Standard & Poor's 500 Index (the "S&P 500 Index") and the Alerian MLP Total Return Index (the "Alerian MLP Index") by assuming $100 was invested in each investment option as of May 14, 2013, the date of the IPO, and reinvestment of all dividends and distributions. The Alerian MLP Index is a composite of the 50 most prominent energy master limited partnerships, or

MLPs, and is calculated using a float-adjusted, capitalization-weighted methodology. The results shown in the graph are based on historical data and should not be considered indicative of future performance.

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Securities Authorized For Issuance Under Equity Compensation Plans

See Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters-Securities Authorized for Issuance Under Equity Compensation Plans for information regarding our equity compensation plans as of December 31, 2015.

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ITEM 6. SELECTED FINANCIAL DATA

The following table presents our selected financial and operating data as of the dates and for the periods indicated. The following table should be read in conjunction with Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

Our historical results of operations for the periods presented below may not be comparable either from period to period or going forward due to the following significant transactions:

- Our IPO in May 2013 resulted in:
- net proceeds of $116.2 million;
- non-recurring charges of $11.0 million;
- our ability to repay substantially all of our pre-existing long-term debt at that time and refinance at more favorable terms; and
- on-going general and administrative costs subsequent to our IPO related to compliance with statutory and other requirements of a publicly traded limited partnership.
- The financial position and results of operations of Direct Fuels were included in the consolidated financial statements from and as of the date of acquisition, May 14, 2013. Our acquisition of Direct Fuels expanded our Fuel segment's operations, gained new customers, improved our earnings, and increased our markets through a larger geographical presence.
- During 2012 and 2014, our Sand segment incurred significant growth capital expenditures to keep pace with rapidly increasing demand for our Northern White frac sand.

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	Year Ended December 31,				
	2015	2014	2013	2012	2011
	($ in thousands, except per unit data)				
Statement of Operations Data:					
Revenues	$711,639	$1,111,254	$873,255	$624,096	$377,488
Cost of goods sold (excluding depreciation, depletion and amortization)	635,825	950,006	767,911	575,408	359,822
Depreciation, depletion and amortization	28,441	24,803	20,828	9,119	6,880
Selling, general and administrative expenses	33,119	38,723	26,835	10,256	9,221
Project terminations	10,652	—	—	—	—
IPO transaction-related costs	—	—	10,966	—	—
Impairment charges	—	—	—	—	762
Income from operations	3,602	97,722	46,715	29,313	803
Interest expense, net	12,554	7,365	10,396	11,005	3,315
Loss (gain) on extinguishment of debt	—	—	907	377	(472)
Gain on extinguishment of trade payable	—	—	—	—	(1,212)
Other expense (income)	(45)	640	(144)	655	(244)
Income (loss) before provision for income taxes	(8,907)	89,717	35,556	17,276	(584)
Provision for income taxes	504	638	386	81	101
Net income (loss)	(9,411)	89,079	35,170	$17,195	$(685)
Less Predecessor net income before May 14, 2013	—	—	13,124		
Post-IPO net income (loss)	$(9,411)	$89,079	$22,046		
Earnings (loss) per common unit (basic)	$(0.39)	$3.70	$0.92		
Earnings (loss) per common unit (diluted)	$(0.39)	$3.70	$0.92		
Balance Sheet Data (at year end):					
Property, plant and equipment, net	$233,630	$238,657	$146,131	$131,414	$88,056
Total assets	$420,048	$432,127	$319,547	$192,406	$126,678
Long-term debt	$295,938	218,063	$94,042	$142,555	$98,604
Statement of Cash Flow Data:					
Net cash provided by (used in):					
Operating activities	$47,325	$86,161	$58,036	$1,137	$(3,606)
Investing activities	$(33,674)	$(88,172)	$(38,009)	$(39,075)	$(14,754)
Financing activities	$343	$6,720	$(19,327)	$32,884	$19,617
Capital expenditures:					
Maintenance (1)	$(2,344)	$(3,240)	$(2,394)	$(2,520)	$(974)
Growth (2)	(33,130)	(74,644)	(18,975)	(37,945)	(14,204)
Total	$(35,474)	$(77,884)	$(21,369)	$(40,465)	$(15,178)
Other Financial Data:					
Cash dividends declared per common unit	$3.08	$4.68	$1.23		
Adjusted EBITDA (3)	$48,386	$131,866	$85,191	$38,574	$9,281

(1) Maintenance capital expenditures are capital expenditures required to maintain, over the long term, our asset base, operating income or operating capacity. The maintenance capital expenditure amounts set forth above are unaudited.

(2) Growth capital expenditures are capital expenditures made to increase, over the long term, our asset base, operating income, or operating capacity. The growth capital expenditure amounts set forth above are unaudited.

(3) See “Adjusted EBITDA” below for a definition of Adjusted EBITDA and a reconciliation to net income (loss).

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Quarterly Data

	Quarter First	Second	Third	Fourth
	($ in thousands, except per unit data)			
2015:				
Revenues	$203,961	$200,852	$176,320	$130,506
Operating income (loss)	12,869	5,692	(8,600)	(6,359)
Net income (loss)	9,491	2,884	(11,898)	(9,888)
Earnings (loss) per common unit (basic) (2)	$0.39	$0.12	$(0.49)	$(0.41)
Earnings (loss) per common unit (diluted) (2)	$0.39	$0.12	$(0.49)	$(0.41)
Cash dividends declared per common unit (3)	$1.41	$1.00	$0.67	$—
2014:				
Revenues	$274,081	$298,273	$296,338	$242,562
Operating income	20,040	22,173	28,592	26,917
Net income	18,486	20,092	26,083	24,418
Earnings per common unit (basic) (2)	$0.77	$0.84	$1.08	$1.01
Earnings per common unit (diluted) (2)	$0.77	$0.84	$1.08	$1.01
Cash dividends declared per common unit (3)	$1.00	$1.13	$1.17	$1.38

(1) Prior to May 14, 2013, our financial statements consist of the combined results of SSS and AEC. Subsequent to the IPO, we have also included the operations of Direct Fuels, which was purchased on May 14, 2013. We accounted for this acquisition as a business combination.

(2) Earnings per common unit are based on the results of operations subsequent to our IPO on May 14, 2013.

(3) Distributions related to the earnings of one quarter are declared and paid in the subsequent quarter.

ADJUSTED EBITDA

Adjusted EBITDA is a non-GAAP financial measure we define generally as: net income plus interest expense, tax expense, depreciation, depletion and amortization expense, non-cash charges and unusual or non-recurring charges less interest income, tax benefits, and selected gains that are unusual or non-recurring. Adjusted EBITDA is used as a supplemental financial measure by our management and external users of our financial statements, such as investors and commercial banks, to assess:

- the financial performance of our assets without regard to the impact of financing methods, capital structure or historical cost basis of our assets;
- the viability of capital expenditure projects and the overall rates of return on alternative investment opportunities;
- our liquidity position and the ability of our assets to generate cash sufficient to make debt payments and to make distributions; and
- our operating performance as compared to those of other companies in our industry without regard to the impact of financing methods and capital structure.

We believe that Adjusted EBITDA provides useful information to investors because, when viewed with our GAAP results and the accompanying reconciliations, it provides a more complete understanding of our performance than GAAP results alone. We also believe that external users of our financial statements benefit from having access to the same financial measures that management uses in evaluating the results of our business. In addition, the lenders under our credit facility use a metric similar to Adjusted EBITDA to measure our compliance with certain financial covenants.

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

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Reconciliation of Net Income (Loss) to Adjusted EBITDA

The following tables present a reconciliation of net income (loss) to Adjusted EBITDA for each segment, corporate, and in total.

	Year Ended December 31, 2015			
	Sand Segment	Fuel Segment	Corporate	Total
	($ in thousands)			
Net income (loss)	$16,700	$(59)	$(26,052)	$(9,411)
Interest expense, net	—	—	12,554	12,554
Other loss	—	—	(45)	(45)
Provision for income taxes	—	—	504	504
Operating income (loss)	16,700	(59)	(13,039)	3,602
Depreciation, depletion and amortization	17,863	10,544	34	28,441
Equity-based compensation expense	—	—	3,532	3,532
Loss (gain) on disposal of equipment	138	8	—	146
Provision for doubtful accounts	1391	150	—	1,541
Accretion	110	—	—	110
Project terminations	10,652	—	—	10,652
Reduction in force	92	—	270	362
Adjusted EBITDA	$46,946	$10,643	$(9,203)	$48,386

	Year Ended December 31, 2014			
	Sand Segment	Fuel Segment	Corporate	Total
	($ in thousands)			
Net income (loss)	$108,956	$6,377	$(26,254)	$89,079
Interest expense, net	—	—	7,365	7,365
Other income	—	—	640	640
Provision for income taxes	—	—	638	638
Operating income (loss)	108,956	6,377	(17,611)	97,722
Depreciation, depletion and amortization	12,777	11,998	28	24,803
Equity-based compensation expense	—	—	9,042	9,042
Loss (gain) on disposal of equipment	19	(11)	—	8
Provision for doubtful accounts	103	150	—	253
Accretion	38	—	—	38
Adjusted EBITDA	$121,893	$18,514	$(8,541)	$131,866

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	Year Ended December 31, 2013			
	Sand Segment	Fuel Segment	Corporate	Total
	($ in thousands)			
Net income (loss)	$55,338	$12,566	$(32,734)	$35,170
Interest expense, net	—	—	10,396	10,396
Loss on extinguishment of debt	—	—	907	907
Other income	—	—	(144)	(144)
Provision for income taxes	—	—	386	386
Operating income (loss)	55,338	12,566	(21,189)	46,715
Depreciation, depletion and amortization	10,458	10,369	1	20,828
IPO transaction-related costs	—	—	10,966	10,966
Equity-based compensation expense	—	—	5,734	5,734
Loss (gain) on disposal of equipment	773	(18)	—	755
Provision for doubtful accounts	51	139	—	190
Accretion	3	—	—	3
Adjusted EBITDA	$66,623	$23,056	$(4,488)	$85,191

	Year Ended December 31, 2012			
	Sand Segment	Fuel Segment	Corporate	Total
	($ in thousands)			
Net income (loss)	$27,384	$2,011	$(12,200)	$17,195
Interest expense, net	—	—	11,005	11,005
Loss on extinguishment of debt	—	—	377	377
Other income	—	—	655	655
Provision for income taxes	—	—	81	81
Operating income (loss)	27,384	2,011	(82)	29,313
Depreciation, depletion and amortization	6,377	2,742	—	9,119
Loss (gain) on disposal of equipment	(33)	5	—	(28)
Provision for doubtful accounts	57	113	—	170
Adjusted EBITDA	$33,785	$4,871	$(82)	$38,574

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	Year Ended December 31, 2011			
	Sand Segment	Fuel Segment	Corporate	Total
	($ in thousands)			
Net income (loss)	$(1,846)	$2,649	$(1,488)	$(685)
Interest expense, net	—	—	3,315	3,315
Loss on extinguishment of debt	—	—	(472)	(472)
Other income	—	—	(244)	(244)
Provision for income taxes	—	—	101	101
Gain on extinguishment of trade payable	—	—	(1,212)	(1,212)
Operating income (loss)	(1,846)	2,649	—	803
Depreciation, depletion and amortization	4,022	2,858	—	6,880
Loss (gain) on disposal of equipment	364	(111)	—	253
Impairment of assets	762	—	—	762
Provision for doubtful accounts	11	—	—	11
Equipment relocation costs	572	—	—	572
Adjusted EBITDA	$3,885	$5,396	$—	$9,281

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

The following discussion analyzes our financial condition and results of operations and should be read in conjunction with our historical consolidated financial statements and notes included elsewhere in this Annual Report.

Acquisition of Direct Fuels

On May 14, 2013, we completed the acquisition of Direct Fuels' net assets for $98.3 million. Direct Fuels operates a motor fuel terminal and transmix processing facility in Texas. The acquisition of Direct Fuels expands our geographic presence into the Dallas-Fort Worth, Texas market. Direct Fuels is part of our Fuel segment.

Acquisition of Mineral Reserves

On July 25, 2014, we completed an acquisition of mineral reserves and related assets to help manage the supply and cost of raw sand to our Wisconsin sand processing plants. See Note 3 to our Consolidated Financial Statements for further information.

In December 2015, we acquired the rights to mine approximately 94 million tons of high quality northern white silica sand reserves in Jackson County, Wisconsin from a subsidiary of PTL, which is wholly-owned by Seventy Seven Energy Inc. (NYSE: SSE). The reserve rights figure is based upon internal analysis of drilling and coring samples, and we have not engaged an expert to assess the volume and quality of these sand reserve rights. The assets acquired include certain owned and leased land, sand deposit leases and related prepaid royalties, and transferable mining and reclamation permits. This transaction not only provides us with an increase to high quality sand reserves but also strengthens our position in the marketplace with a leading pressure pumper across a number of shale plays in North America. In consideration for the assets, PTL and SSS amended and restated the existing supply agreement between the parties and entered into a new sand purchase option agreement that provide PTL with a market-based discount on sand purchased from SSS. Under the new agreements with PTL, SSS has the option to supply the contracted tons from its existing footprint of northern white sand operations or construct a new sand mine and dry plant in Jackson County, Wisconsin. Given the current challenging market conditions for proppant demand, we have deferred the construction of the new facility until the North American oil and gas markets improve.

How We Evaluate Our Operations

Our management uses a variety of financial and operational metrics to analyze our performance. We evaluate the performance of our Sand and Fuel segments based on their volumes sold, revenues, operating income and Adjusted EBITDA. We view these metrics as important factors in evaluating our profitability and review these measurements frequently to analyze trends and make decisions.

Sales volumes

We view the total volume of frac sand and refined products that we sell as an important measure of our ability to effectively utilize our assets. Higher volumes improve profitability through the spreading of fixed costs over greater volumes. Our sales volumes are subject to seasonality, particularly in our Sand segment. Please see Part I, Item 1. Business.

Adjusted EBITDA

Adjusted EBITDA, a non-GAAP financial measure, is used as supplemental measures by our management and by external users of our financial statements such as investors, commercial banks, research analysts and others, 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; 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.

See Item 6. Selected Financial and Operating Data—Adjusted EBITDA for a discussion of Adjusted EBITDA and a reconciliation to net income (loss).

Recent Trends

Sand Segment

Beginning in late 2014, the market prices for crude oil and refined products began a steep and protracted decline which has continued throughout 2015. This has greatly impacted the demand for frac sand as drilling and completion of new oil and natural gas wells has been significantly curtailed in North America. As a result, we are experiencing continued, significant downward pressure on pricing while rig counts and oil prices continue to decline. We expect drilling and well completion activity levels, based on indications from our customers and other industry sources, will be extremely weak in the upcoming year. While we do ultimately

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expect a recovery in the frac sand market, we now expect that any market recovery in our frac sand business will occur during the second half of 2016 or, potentially, not until 2017. We expect that this decline in completion activity will result in weak frac sand demand, and put further pressure on frac sand prices, for an extended period of time.

In the face of these conditions, SSS has taken aggressive actions to solidify its strategic position, improve revenue, and reduce costs:

Cost Reductions

In order to conserve liquidity and respond to the industry downturn, we have become increasingly focused on prudently reducing costs while maintaining our ability to quickly respond to increased demand when the market begins to recover in the future. We have already implemented plans, but will continue to aggressively contain costs in the future. As the market trends have had the most impact on our frac sand business, we have concentrated our efforts on the Sand segment. Such measures include:

- We reduced permanent headcount, with most of these reductions occurring in the fourth quarter of 2015.
- We are minimizing the overall cost of sand sold by finding the lowest cost combinations of sand source, production location and transportation providers wherever possible.
- We began shutting down our more expensive wet plants for winter earlier than normal this year, as we have sufficient wet sand stockpiled for processing in our dry plants throughout the winter months.
- We have temporarily idled our Wisconsin wet plants with the highest cost per ton, and we have strategically shifted sourcing of wet sand from higher cost sources to lower cost sources as demand for our frac sand has decreased.
- In January 2016, we temporarily idled one Wisconsin dry plant with high costs per ton and shifted the production to the other Wisconsin dry plants.
- We began using new mining techniques at two of our Wisconsin mines in the third quarter of 2015, and plan to introduce these techniques to our Kosse mine in the near term. We expect to see over $1 per ton savings for frac sand sourced from these mines as these techniques are fully implemented and the resulting finished sand is sold.
- We introduced new processing techniques at our Kosse plant in the third quarter of 2015 that allowed us to inexpensively extract significant amounts of saleable frac sand from previously mined and discarded waste sand.
- We have negotiated, and continue to negotiate, price concessions and purchase commitment concessions from our major vendors, such as rail transportation providers, mine operators, transload facilities operators, and professional services providers.
- We cut our planned 2015 capital expenditures to less than half of the $110 million planned at the beginning of the year, including the first quarter termination of a sand facilities project described below. In 2016, we will minimize our capital expenditures to include only those projects with the potential for rapid returns, and comply with our bank covenants that limit capital expenditures.

Development of Sand Distribution System

In 2013 and 2014, we developed our sand distribution system through the addition of third-party transload facilities in the basins in which our customers operate. We are able to charge higher prices for these in-basin sales than for FOB-plant sales to provide this additional service and convenience to our customers and to cover related transportation and other services costs. However, these additional markups for in-basin sales have also been cut due to pricing pressures during this industry down-cycle, and we expect these logistics-based service markups to remain weak until the frac sand industry recovers.

Increasing Fixed Costs for Sand

During 2014, our rapidly expanding frac sand business required us to contract for numerous railcars to be delivered and leased in the future as well as contracting for new transload facilities discussed above. As our railcar fleet and distribution system has expanded while sales volumes contracted and sand prices declined, our fixed costs per ton have increased, and these costs will continue to increase as new railcars are placed in service. These increasing fixed costs may offset the impact of our planned cost reduction activities described above. We are currently working with our vendors to delay further shipment of railcars in the future, and to provide relief on certain of our fixed costs similar to the pricing relief that we provided to our own customers. It is not certain if we will be successful in reducing or delaying these costs.

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Expansion of Sand Resources

In 2014, our Sand segment added the LP mine and wet plant, Thompson Hills mine and wet plant, and the Arland dry plant. We also acquired the Church Road mineral reserves and related assets in July 2014 to better manage the cost of raw sand for a portion of our Wisconsin plants' production.

In December 2015, we acquired the rights to mine approximately 94 million tons of high quality northern white silica sand reserves in Jackson County, Wisconsin from a subsidiary of PTL, which is wholly-owned by Seventy Seven Energy Inc. (NYSE: SSE). The reserve rights figure is based upon internal analysis of drilling and coring samples, and we have not engaged an expert to assess the volume and quality of these sand reserve rights. The assets acquired include certain owned and leased land, sand deposit leases and related prepaid royalties, and transferable mining and reclamation permits. This transaction not only provides us with an increase to high quality sand reserves but also strengthens our position in the marketplace with a leading pressure pumper across a number of shale plays in North America. In consideration for the assets, PTL and SSS amended and restated the existing supply agreement between the parties and entered into a new sand purchase option agreement that provide PTL with a market-based discount on sand purchased from SSS. Under the new agreements with PTL, SSS has the option to supply the contracted tons from its existing footprint of northern white sand operations or construct a new sand mine and dry plant in Jackson County, Wisconsin. Given the current challenging market conditions for proppant demand, we have deferred the construction of the new facility until the North American oil and gas markets improve.

Technology driven proppant products.

In September 2015, we introduced a unique, technically advanced proppant to the oil and gas industry. This new dustless proppant, brand named SandGuard™, will improve the handling, in-basin management, and job-site implementation of the hydraulic fracturing of oil and gas wells. With a SandGuard™ treatment production circuit at our Barron dry plant, we will have the ability to enhance the already strong qualities of our Northern White silica sand as a more protected proppant soon to be marketed to all major North American basins.

In November 2015, we acquired 12 patents and other intellectual property assets from AquaSmart Enterprises LLC for their Self-Suspending Proppant technology. The product brand will be marketed as SandMaxx™. While subject to field testing and data validation, this new technology offers the potential to increase productivity and completion efficiencies in oil and gas wells while improving pump time, and well site economics. At our Barron dry plant, we recently completed the construction of a pilot production circuit to produce in excess of 175,000 tons per year of SandMaxx™ product. This pilot production circuit will use proprietary and patented technology to coat all grades of standard frac sand. While market acceptance of SandMaxx™ is subject to the successful completion of field trial testing, we are developing plans for a coating plant that will be necessary in order to produce commercially viable volumes of SandMaxx™.

We will continue to work toward transforming our sand segment from a commodity business to a more value-driven approach by developing capabilities and products that assist in enabling us to increase our presence in larger, more profitable markets.

Project Terminations

In 2014 and 2015, we began development of sand processing facilities in Independence, Wisconsin and other small projects in Ohio and Missouri. Due to a number of complications, such as an increase in projected operating costs and a decline in the market price and demand for frac sand in early 2015, we determined that these projects were no longer economically viable. In 2015, we recorded a $9.3 million charge to earnings, of which $9.2 million related to the Independence, Wisconsin facilities. This charge to earnings included items such as engineering, legal and other professional service fees, site preparation costs, and writedowns of assets to estimated net realizable value. Management committed to a plan to discontinue these project in April 2015. In accordance with FASB ASC 420, Exit or Disposal Cost Obligations, any contract termination charges and estimated values of continuing contractual obligations for which we will receive no future value will be recognized as a charge to earnings as of the contract termination date or cease-use date. We estimated these contract termination charges to be approximately $1.4 million. These liabilities will be reviewed periodically and may be adjusted when necessary, but we do not expect any such adjustments to be significant.

Fuel Segment

Total consumption of liquid fuels in the United States, including both fossil fuels and biofuels, is expected to remain relatively stable from 19.0 million barrels per day in 2013 to 19.3 million barrels per day in 2040, according to the Annual Energy Outlook 2015 published by the Energy Information Administration in April 2015. The transportation sector is expected to continue to account for the largest percentage of demand for liquid fuels (as measured by energy content) through 2040.

Diesel Fuel

We believe that transmix processing volumes generally increase or decrease at approximately the same rate as the consumption of liquid fuels in the United States. Transmix processing volumes are also driven by changes in governmental regulations. We believe the only pending regulatory changes that will impact the volume of transmix produced in the United States are the regulations promulgated by the EPA in mid-2006 that required a reduction in the sulfur content of diesel fuel. Under these regulations, which resulted in significant increases in transmix volumes following their promulgation in 2006, the maximum allowable sulfur content for on-road diesel fuel was reduced on a phased basis from 500 ppm (low sulfur diesel) to 15 ppm (ultra-low sulfur diesel). In order to prevent contamination of the lower-sulfur fuels traveling through pipelines, pipeline operators had to reconfigure the way fuel was transported, which resulted in more interfaces between products and deeper “cuts” in those interfaces. Under the EPA's regulations, all on-road and off-road diesel had to meet a 15 ppm sulfur standard as of June 2010. A settlement agreement with the EPA indicates that the agency will allow use of 500 ppm diesel produced by transmix processors in locomotive engines as long as there is a market for it; however, railroads must begin purchasing Tier 4 locomotives, which only accept 15 ppm sulfur diesel, starting in 2015. As a result, 500 ppm sulfur diesel was phased out of the railroad market beginning in the middle of 2015. However, the settlement agreement allows us and other transmix process to sell 500 ppm diesel produced to certain marine markets with no phase-out date. During the quarter ended June 30, 2015, we adopted business practices to accommodate the shift in product mix from our railroad customers. The shift to other uses was less profitable in the third quarter. We have worked with the suppliers of our transmix to mitigate the impact to our bottom line going forward. To remediate this condition long term, we have contracted to purchase and install two hydrotreaters designed to remove sulfur to the level of 15 ppm. At 15 ppm sulfur, diesel we derive from transmix can be sold for any legal use including railroads and on-road transportation. We will install one unit at our Dallas-Fort. Worth, Texas facility which will become operational in April 2016, and a second unit at our Birmingham, Alabama facility which will be operational in July 2016. We plan to invest approximately $17 million for both units, of which we had already paid $6.7 million as of December 31, 2015.

2016 Outlook

The supply of crude oil has been growing while demand has been largely stagnant, causing a decline in the price of crude oil, which reduced oil and gas drilling activity in North America shale plays. The stagnation in energy consumption is a relatively recent phenomenon and when combined with the expanded supply of crude oil, it creates substantial uncertainty in predicting a turnaround for the frac sand industry. These factors impact our Sand segment negatively by weakening frac sand selling price, and decreasing the frac sand volume that we sell. We do not expect a recovery of the frac sand market until later in 2016, and possibility extending into 2017.

Recent decreases in spot market prices for crude oil and natural gas have led to a corresponding decrease in spot market prices for proppant that we believe will continue into 2016. There is wide variability in analyst expectations for drilling activity in 2016 and beyond, making it very difficult to forecast. However, while overall sand consumption is declining as well count decreases, the amount of sand per well continues to increase, setting the stage for a strong recovery. The drilled but uncompleted wells backlog remains at elevated levels, driving further demand for proppant once those wells are fracked. Re-fracking of existing, older wells is also starting to gain momentum and could add to a proppant demand rebound. We expect that the secular trends of the industry will make any cyclical recovery very strong. Further, we believe that our strong logistics network and capabilities will continue to help us differentiate ourselves from those that lack critical infrastructure. In addition, we believe that the trend of industry consolidation that we saw commence in the summer of 2014 will continue.

We believe that our Fuel segment will contribute incrementally to 2016 results. While our 2016 Fuel segment expectation is generally positive, we anticipate that the current backwardated market will continue in the first quarter and possibly the first half of 2016 before market pricing allows Fuel margins to return to more historic levels. We continue to look for alternative markets for our diesel that contains over 15 ppm of sulfur, as well as alternative treatment methods to increase diesel margins from transmix. We adopted business practices to accommodate the shift in product mix from our railroad customers. We have contracted to purchase and install two hydrotreaters designed to remove sulfur to the level of 15 ppm. At 15 ppm sulfur, diesel we derive from transmix can be sold for any legal use including railroads and on-road transportation. We will install one unit at our Dallas-Ft. Worth, Texas facility and a second unit at our Birmingham, Alabama facility. We expect the hydrotreaters to become operational in 2016.

Our operating results, cash flows and liquidity were negatively affected in 2015 by the aforementioned decline in oil and natural gas prices. Companies servicing the oil and natural gas industry experienced reduced access to credit and capital markets as compared to previous years, a trend which we expect to continue in 2016. Sustained downward pressure on oil and natural gas prices may further exacerbate these challenges and negatively impact our liquidity position in 2016. Please see “Liquidity and Capital Resources” below for more detail.

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Results of Operations

The following table summarizes our consolidated operating results for 2015, 2014 and 2013.

	Year Ended December 31,		
	2015	2014	2013
	($ in thousands)		
Revenues	$711,639	$1,111,254	$873,255
Operating expenses:			
Cost of goods sold (excluding depreciation, depletion and amortization)	635,825	950,006	767,911
Depreciation, depletion and amortization	28,441	24,803	20,828
Selling, general and administrative expenses	33,119	38,723	26,835
Project terminations	10,652	—	—
IPO transaction-related costs	—	—	10,966
Total operating expenses	708,037	1,013,532	826,540
Operating income	3,602	97,722	46,715
Other expense (income):			
Interest expense	12,554	7,365	10,396
Loss on extinguishment of debt	—	—	907
Other expense (income)	(45)	640	(144)
Total other expense	12,509	8,005	11,159
Income (loss) before provision income for taxes	(8,907)	89,717	35,556
Provision for income taxes	504	638	386
Net income (loss)	$(9,411)	$89,079	$35,170
Adjusted EBITDA (a)	$48,386	$131,866	$85,191

(a) See Item 6. Selected Financial and Operating Data—Adjusted EBITDA for a discussion of Adjusted EBITDA and a reconciliation to net income (loss).

Consolidated Summary

Our company has experienced significant change over the past three years, growing from a net income of $35.2 million in 2013 to a net income of $89.1 million in 2014 and a net loss of $9.4 million in 2015. Most notable are the following events:

- substantial growth of our Sand segment through addition of a dry plant in Wisconsin in each of 2011, 2012 and 2014, which significantly increased our overall production and profitability;
- the acquisition of Direct Fuels to substantially increase our Fuel segment in 2013;
- our IPO in 2013, which brought these two segments together for the first time and allowed us to refinance our debt at more favorable terms going forward;
- development of a network of sand transload sites in 2013 and 2014; and
- the market prices for crude oil and refined products began a steep and protracted decline in late 2014 which continued throughout 2015 impacting our Sand and Fuel segments.

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Sand Segment

	Year Ended December 31,		
	2015	2014	2013
	($ in thousands)		
Revenues	$269,518	$341,836	$167,768
Operating expenses:			
Cost of goods sold (excluding depreciation, depletion and amortization)	209,161	204,282	91,416
Depreciation, depletion and amortization	17,863	12,777	10,458
Selling, general and administrative expenses	15,142	15,821	10,556
Project terminations	10,652	—	—
Operating income	$16,700	$108,956	$55,338
Adjusted EBITDA (a)	$46,946	$121,893	$66,623
Total tons of sand sold (in thousands)	3,392	4,306	2,651
Tons of sand produced by dry plant (in thousands):			
Arland, Wisconsin facility	1,064	124	—
Barron, Wisconsin facility	1,536	2,224	1,334
New Auburn, Wisconsin facility	604	1,394	1,330
Kosse, Texas facility	277	299	115
Total	3,481	4,041	2,779

(a) See Item 6. Selected Financial and Operating Data—Adjusted EBITDA for a discussion of Adjusted EBITDA and a reconciliation to net income (loss).

Overview

The operating income for our sand segment saw substantial growth from an operating income of $55.3 million in 2013 to $109.0 million in 2014 but decreased to $16.7 million in 2015 due to the steep decline in the demand and pricing of frac sand. Management has focused on growing this segment of our business by adding the Barron plant in late 2012 and the Arland plant in late 2014, as well as developing our distribution and logistics services to better serve our customers through additional transload sites in 2013 and 2014. At year-end 2015, we had 15 transload sites in the U.S. and Canada. Many of these sites are considerably distant from our processing facilities in Wisconsin. Due to the distance to these markets, we charge higher prices to recover freight and handling. This condition increases our revenues and margin, but the margin percentage at our transload sites is lower than for sand sold directly from our Wisconsin plants due to lower markups on the incremental transportation costs.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

Revenues

Sand revenues decreased by $72.3 million, or 21%, from 2014 to 2015 primarily due to significant price decreases and a 21% decrease in total volumes sold as a result of the downturn in market demand for frac sand. However, we have increased the volumes sold through transload sites from 23% to 42% of total volumes sold. We expanded our logistics and distribution network with the addition of transload facilities in the U.S. and Canada to serve our customers in various shale plays and basins. We generally charge higher prices at our transload sites in order to cover the additional costs for transportation from our plants to the transload sites. Management continues to focus on initiatives to strengthen and improve logistics service, including increased storage capacity and access to remote transload sites. These logistics-based initiatives are intended to complement and enhance customer support.

The major changes from 2014 to 2015 are as follows:

- $85.7 million decrease in sales of Northern White sand (excluding estimated transportation markups and shortfall revenues), relating primarily to a 21% decrease in volumes sold as well as decreased pricing in light of current market conditions for frac sand;
-

an estimated $2.1 million decrease for significant reductions in markups per ton sold through transload sites, net of increased volumes sold through these sites; offset by

- $11.1 million of shortfall revenues recognized on take-or-pay customer contracts in 2015. We do not expect to recognize any take-or-pay shortfall revenues in 2016 due to recent revisions to certain take-or-pay contracts;

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- $2.6 million of business interruption insurance proceeds received in 2015 to reimburse us for lost sales during a time of equipment failure in 2014; and
- $1.7 million increase in sales of native Texas sand (from our Kosse plant) due to increased markups.

Cost of goods sold (excluding depreciation, depletion and amortization)

Our cost of goods sold consists primarily of direct costs such as purchased sand, transportation to the plant or to transload facilities, mining and processing costs, and plant wages as well as indirect costs such as plant repairs and maintenance. All major components of our direct costs decreased with our decreased production and with the operations of our plants, except transportation costs as we expanded our distribution network with new transload sites. The plant maintenance and repairs did not increase significantly, as the Wisconsin plants are still quite new. The most significant components of the $4.9 million increase from 2014 to 2015 are:

- $26.2 million increase in rail transportation-related expense, due mainly to higher railcar lease expense and rail use charges as we expand our shipping operations to transload facilities, and primarily including:
- $12.8 million increased rail lease expense;
- $11.1 million increased rail shipping costs;
- $2.2 million increase railcar storage costs; and
- $5.6 million increase in costs of transload facilities; offset by
- $26.9 million decrease in the total cost to acquire and produce wet and dry sand, due mainly to lower sales volumes and lower-cost sources for wet sand.

Depreciation, depletion and amortization

Depreciation, depletion and amortization increased by $5.1 million mainly due to the full year deprecation in 2015 of the Arland dry plant that was placed in service in December 2014 as well as full year depletion in 2015 on the mineral reserves purchased in July 2014.

Selling, general and administrative expense

The $0.7 million decrease in selling, general and administrative expense is attributable primarily to:

- $1.7 million decrease for employee-related costs, primarily incentive compensation due to greatly decreased segment profits; and
- $1.0 million refund of legal fees associated with past litigation, offset by
- $1.2 million increase in bad debt expense; and
- $0.7 million increase in property taxes.

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013

Revenues

Sand revenues increased by $174.1 million, or 104%, from 2013 to 2014. This increase is attributable primarily to a 62% increase in total volumes sold, due primarily to the full utilization of our Barron dry plant in 2014 and, to a lesser extent, increased sales of native Texas sand and the opening of our Arland facility in December 2014. We also expanded our logistics and distribution network with the addition of transload facilities in the U.S. and Canada to serve our customers in various shale plays and basins. We generally charge higher prices at our transload sites in order to cover the additional costs for transportation from our plants to the transload sites. Management continues to focus on initiatives to strengthen and improve logistics service, including increased storage capacity and access to remote transload sites. These logistics-based initiatives are intended to complement and enhance customer support.

The major changes from 2013 to 2014 are as follows:

- an estimated $88.4 million increase for higher markups related to transportation for increased sales through transload sites;
- $78.6 million increase in sales of Northern White sand (excluding estimated transportation markups), relating primarily to a 58% increase in volumes sold; and
- $7.1 million increase in sales of native Texas sand (from our Kosse plant) due to a 160% increase in volumes sold.

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Cost of goods sold (excluding depreciation, depletion and amortization)

Our cost of goods sold consists primarily of direct costs such as purchased sand, transportation to the plant or to transload facilities, mining and processing costs, and plant wages as well as indirect costs such as plant repairs and maintenance. All major components of our direct costs increased with our increased production and with the operations of our new plants, particularly transportation costs as we expanded our distribution network with new transload sites. The plant maintenance and repairs did not increase significantly, as the Wisconsin plants are still quite new. The most significant components of the $112.9 million increase from 2013 to 2014 are:

- $72.2 million increased rail transportation-related expense, due mainly to higher railcar lease expense and rail use charges as we expand our shipping operations to transload facilities, and primarily including:
- $56.7 million increased rail shipping costs;
- $15.5 million increased railcar lease expense; and
- $22.5 million increased cost of produced sand, due to a 62.4% increase in total sand sold;
- $9.4 million increased transload service expense; and
- $3.2 million increased utilities expenses for higher utilization of our various plants.

Depreciation, depletion and amortization

The $2.3 million increase in depreciation, depletion and amortization is due primarily to $1.1 million of depletion expense for the new Wisconsin sand reserves purchased in July 2014 as well as depreciation on other assets placed in service for wet plants and the Arland dry plant throughout the year.

Selling, general and administrative expense

The $5.3 million increase in selling, general and administrative expense is attributable to support for our expanded operations, including:

- $3.4 million increase for employee-related costs, primarily incentive compensation due to greatly increased segment profits; and
- $1.4 million increase for insurance and professional services; and
- $0.4 million increase for software support and other information technology needs;

Fuel Segment

	Year Ended December 31,		
	2015	2014	2013
	($ in thousands)		
Revenues	$442,121	$769,418	$705,487
Operating expenses:			
Cost of goods sold (excluding depreciation, depletion and amortization)	426,664	745,724	676,495
Depreciation, depletion and amortization	10,544	11,998	10,369
Selling, general and administrative expenses	4,972	5,319	6,057
Operating income (loss)	$(59)	$6,377	$12,566
Adjusted EBITDA (a)	$10,643	$18,514	$23,056
Volume of refined fuels sold (gallons in thousands)	240,132	264,364	224,484
Volume of terminal throughput (gallons in thousands)	123,180	210,665	207,280
Volume of transmix refined (gallons in thousands)	93,128	116,611	91,813
Refined transmix as a percent of total refined fuels sold	38.8%	44.1%	40.9%

(a) See Item 6. Selected Financial and Operating Data—Adjusted EBITDA for a discussion of Adjusted EBITDA and a reconciliation to net income (loss).

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Overview

Operating income for our Fuel segment decreased from $6.4 million in 2014 to $(0.1) million in 2015. The 2014 and 2015 declines in fuel prices led to extended market backwardation, greatly eroding margins on fuel.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

Revenues

The $327.3 million, or 43%, decrease in Fuel segment revenues is attributable to a 9% decrease in total volumes sold and declines in fuel prices, generally. The decrease in volume relates directly to the market volatility and our inability to sell 500 ppm sulfur diesel to the railroads beginning in mid-2015.

The major components of the total $327.3 million decrease in revenues are:

- $262.4 million decrease due to lower average fuel sales prices;
- $65.4 million decrease for lower volumes of fuel sold; offset by
- $0.8 million increase in excise and other transaction taxes. These taxes are offset on a one-to-one basis with excise and similar taxes in cost of goods sold.

Cost of goods sold (excluding depreciation, depletion and amortization)

Our cost of goods sold consists primarily of direct costs associated with the purchase of refined fuels, transmix feedstock, plant labor and burden, and costs to operate our transmix and terminal facilities.

The major components of the $319.1 million total decrease from 2014 to 2015 are:

- $257.5 million decrease for lower average fuel purchase prices;
- $62.5 million decrease for lower volumes of fuel sold; offset by
- $0.8 million increase in excise and other transaction taxes.

Fuel segment cost of goods sold include excise and similar taxes. These taxes are offset on a one-to-one basis with excise and similar taxes in revenues.

Depreciation, depletion and amortization

The $1.5 million decrease in depreciation, depletion and amortization is due primarily to full amortization of certain short-term intangible assets acquired in May 2013.

Selling, general and administrative expense

Our selling, general and administrative expenses decreased $0.3 million, due primarily to decreased incentive compensation.

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013

Revenues

The $63.9 million, or 9%, increase in Fuel segment revenues is attributable to an 18% increase in total volumes sold. The increase in volume relates directly to incremental sales derived from Direct Fuels after the purchase on May 14, 2013 as well as modest increases in fuel sales in the Birmingham, AL market. Direct Fuels recorded approximately $130.0 million of revenues from January 1, 2014 through May 13, 2014, for which there are no corresponding 2013 sales reported. These incremental revenues in the first half of 2014 were more than offset by revenue decreases in the last half of 2014 due to market volatility.

The major components of the total $63.9 million increase in revenues are:

- $115.9 million increase due to increased volumes, mainly for inclusion of a full year of Direct Fuels' operations in 2014, offset by lower volumes sold in the last half of 2014 when prices had dropped;
- $54.7 million decrease in sales prices due primarily to drastic reduction in the market price of fuel late in 2014; and
- $3.1 million increase in excise and similar taxes.

Fuel segment revenues include excise and similar taxes. These taxes are offset on a one-to-one basis with excise and similar taxes in cost of goods sold.

Cost of goods sold (excluding depreciation, depletion and amortization)

Our cost of goods sold consists primarily of direct costs associated with the purchase of refined fuels, transmix feedstock, plant labor and burden, and costs to operate our transmix and terminal facilities. Direct Fuels incurred approximately $124.6 million

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of cost of goods sold from January 1, 2014 through May 13, 2014, for which there are no corresponding 2013 amounts reported. These incremental costs were more than offset by the steep price declines in the second half of 2014.

The major components of the $69.2 million total increase from 2013 to 2014 are:

- $109.6 million increase due to increased volumes, mainly for inclusion of a full year of Direct Fuels' operations in 2014;
- $44.3 million decrease in fuel purchase prices due primarily to drastic reduction in the market price of fuel late in 2014, particularly in the fourth quarter; and
- $3.1 million increase in excise and similar taxes.

Fuel segment cost of goods sold includes excise and similar taxes. These taxes are offset on a one-to-one basis with excise and similar taxes in revenues.

Depreciation, depletion and amortization

The $1.6 million increase in depreciation, depletion and amortization is due primarily to recognizing a full year of expense in 2014 for the assets acquired with our purchase of Direct Fuels on May 14, 2013.

Selling, general and administrative expense

Our selling, general and administrative expenses decreased $0.7 million, due primarily to decreased incentive compensation.

Corporate

	Year Ended December 31,		
	2015	2014	2013
	($ in thousands)		
Depreciation, depletion and amortization	$34	$28	$1
Selling, general and administrative expenses	13,005	17,583	10,222
IPO transaction-related costs	—	—	10,966
Operating loss	(13,039)	(17,611)	(21,189)
Other expense (income):			
Interest expense, net	12,554	7,365	10,396
Loss on extinguishment of debt	—	—	907
Other	(45)	640	(144)
Income (loss) before provision for income taxes	(25,548)	(25,616)	(32,348)
Provision for income taxes	504	638	386
Unallocated corporate loss	$(26,052)	$(26,254)	$(32,734)
Adjusted EBITDA (a)	$(9,203)	$(8,541)	$(4,488)

(a) See Item 6. Selected Financial and Operating Data—Adjusted EBITDA for a discussion of Adjusted EBITDA and a reconciliation to net income (loss).

Overview

All of our IPO transaction-related costs, equity-based compensation, and other overhead items not allocated to our two segments are included in corporate. As the Sand and Fuel segments were operated separately without consolidated EMES management oversight prior to our IPO in May 2013, and other costs such as equity-based compensation and costs of being a publicly traded limited partnership began at that same time, corporate expenses increased significantly in 2013 compared to any prior year and continued to increase in 2014 due to a full year of results for the expanded corporate oversight activities.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

Selling, general and administrative expenses

The largest component of the $4.6 million decrease in corporate selling, general and administrative expenses is the $5.5 million decrease in equity-based compensation expense resulting from the vesting of phantom units in May of 2014 and 2015. See Note 12 to our Consolidated Financial Statements for further discussion of equity-based compensation. This decrease is partially offset by a $1.0 million increase in professional fees.

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Interest expense, net

Our net interest expense increased $5.2 million mainly due to higher average balances on outstanding debt and higher average interest rates in 2015. As of December 31, 2015 our outstanding borrowings under the Credit Agreement bore interest at a weighted-average rate of 5.08% compared to 2.78% as of December 31, 2014.

Other

The net change from 2014 to 2015 is due primarily to a non-recurring $0.7 million loss on settlement of pre-existing agreements in connection with our acquisition of mining assets in 2014.

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013

Selling, general and administrative expenses

The largest component of the $7.4 million increase in corporate selling, general and administrative expenses is the $3.3 million increase in equity-based compensation recorded subsequent to our IPO. See Note 11 to our Consolidated Financial Statements for further discussion of equity-based compensation. The remaining increase is primarily for professional fees, salaries and other related costs necessary to manage our newly combined business and provide the incremental services necessary for a publicly traded partnership (such as compliance with SEC, Sarbanes-Oxley, and NYSE requirements, additional insurance coverage and director fees). We incurred and recorded these costs for a full year in 2014 versus only the portion of 2013 subsequent to our IPO.

IPO transaction-related costs

We incurred generally non-recurring expenses related directly to the IPO 2013. These costs consisted primarily of incentive compensation and payroll-related costs paid to management. In addition, we incurred indirect legal, accounting, and other professional fees associated with the IPO transaction not related to the issuance of equity and debt. See Note 12 to our Consolidated Financial Statements for further details.

Interest expense, net

Our net interest expense decreased $3.2 million due to much lower average interest rates despite having higher average balances of interest-bearing obligations in 2014 than in 2013. In the last half of 2012, we had added a substantial amount of long-term debt, which was incurring interest expense at relatively high interest rates until we refinanced substantially all of our debt in connection with our IPO on May 2013. Beginning in May 2013, we are subject to much more favorable terms, which we expect to continue during the term of our current credit agreement. See Note 8 to our Consolidated Financial Statements for a discussion of long-term debt.

Other

The net change from 2013 to 2014 is due primarily to a non-recurring $0.7 million loss on settlement of pre-existing agreements in connection with our acquisition of mining assets in 2014.

Liquidity and Capital Resources

Our principal liquidity requirements are to finance current operations, fund capital expenditures, including acquisitions from time to time, to service our debt, and to pay distributions to partners. Our sources of liquidity generally include cash generated by our operations, borrowings under our revolving line of credit, and issuances of equity and debt securities. While cash flows from our operating activities are a key contributor to our liquidity, we also depend on borrowings under our revolving line of credit to fund daily cash requirements because the timing of operating and investing cash flows varies, from day-to-day. Our ability to borrow against our revolving credit facility is also dependent on having sufficient collateral that includes accounts receivable, inventories, and sand reserves and reserve rights; and the sand reserve collateral is the largest component of security under the credit agreement. With the recent decline in frac sand prices, we expect the value of our sand reserve to decrease when the bank conducts its periodic collateral appraisal in early 2016. A material decrease in our sand reserve collateral could adversely affect our ability to borrow under the revolving credit facility. As described below, we amended our bank agreement in November 2015, and this amendment changed our financial covenants and other key provisions of the loan agreement. As a result of the November 2015 amendment, we are required to meet a minimum consolidated EBITDA (as defined by the bank) beginning for the quarter ended December 31, 2015. While we met our loan covenants at December 31, 2015, we may not meet our covenants at some point in 2016 due to the continued deterioration of the oil and gas market generally, and the frac sand market in particular. We have now adopted new strategies to address our possible lack of liquidity and position the company to not only weather this protracted industry downturn, but to return quickly to profitability when improved market opportunities return. Our liquidity strategies include, but are not limited to:

- Negotiate reduced cost of our railcars under lease or future lease commitment through:

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- cancellation or deferral of all future railcar deliveries (we have successfully negotiated the cancellation or deferred a significant number of future deliveries); and
- railcar lease rate concessions.
- Continued aggressive cost reductions, which started in 2015, including but not limited to:
- significantly reduced headcount across all business units in 2015 and early 2016;
- having already achieved rate concessions from certain vendors, such as rail transportation, trucking, and professional fees, we will seek to leverage these gains with our other vendors;
- successfully negotiated cessation of take-or-pay commitments with certain vendors; and
- temporarily idling the sand processing plants with the most expensive cost structures, and sourcing our frac sand from the most cost-effective plants (we have already idled our Arland dry plant and the New Auburn wet plant).
- Differentiate our sand products from our competitors by pursuing the development, testing, and marketing of new technology, such as our SandGuard™ and SandMaxx™ products, which should yield higher margins, if successful.
- Complete the hydrotreaters at our Fuel segment locations in Dallas-Fort Worth and Birmingham, which we believe will enhance our margins and open new outlets for our transmix processing activities.
- In January 2016, we engaged a third party expert to identify and pursue strategic alternatives, including the marketing and possible sale of our Fuel segment at a favorable price.
- Continue in discussions with our bank group to realign our credit agreement and its covenants to meet our liquidity needs during this downturn:
- reduce our bank debt with proceeds from any strategic sale transactions, such as our Fuel segment;
- reduce the overall lending commitment; and
- reset covenants based on revised forecasted liquidity requirements.
- If necessary and available, we may seek alternative financing such as a capital infusion.
- Reducing or delaying capital investments that do not produce short-term return on investment.

However, we cannot assure you that we would be able to successfully execute our strategies described above, or obtain alternative financing, if necessary, on commercially reasonable terms or at all, or that implementing these strategies would allow us to meet our debt obligations and capital requirements or that these actions would be permitted under the terms of our various debt instruments.

Failure to maintain compliance with the covenants and ratios required under our Credit Agreement, such as maintaining certain levels of excess available borrowings and generating minimum amounts of consolidated EBITDA on a quarterly basis, or our inability to generate sufficient cash flow to satisfy our debt obligations could negatively impact our ability to incur additional indebtedness under our revolving credit facility, or elsewhere, on acceptable terms or at all. The inability to borrow sufficient funds to meet our cash requirements would adversely affect our operations, cash flows, financial condition and our ability to pay distributions to our unitholders. Further, if for any reason we are unable maintain compliance with any of our covenants in our Credit Agreement or to meet our debt service and repayment obligations, we would be in default under the terms of our Credit Agreement, which would allow our creditors at that time to declare all outstanding indebtedness to be due and payable. In the event of a default, the lenders under our Credit Agreement could foreclose against our assets securing their borrowings and we could be forced into bankruptcy or liquidation. If the amounts outstanding under our Credit Agreement or any of our other indebtedness were to be accelerated, we cannot assure you that our assets would be sufficient to repay in full the money owed to the lenders or to our other debt holders.

Credit Agreement

On May 14, 2013, we entered into a $150 million revolving credit and security agreement (as amended and restated, the "Credit Agreement") among Emerge Energy Services LP, as parent guarantor, each of its subsidiaries, as borrowers (the "Borrowers"), and PNC Bank, National Association, as administrative agent and collateral agent. Substantially all of the assets of the Borrowers are pledged as collateral under the Credit Agreement.

On December 10, 2013, we amended the Credit Agreement to revise certain definitions and to increase the commitment amount for our revolving loan credit facility to $200 million.

On June 27, 2014, we amended and restated the Credit Agreement to, among other things:

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- increase our revolving credit facility (the "Credit Facility") to $350 million, which we may increase from time to time upon our satisfaction of certain conditions by up to an aggregate of $150 million;
- increase the sublimit for the issuance of letters of credit to $30 million;
- revise financial covenants as discussed below; and
- extend the maturity date to June 27, 2019.

We also incur a commitment fee of 0.375% on committed amounts that are neither used for borrowings nor under letters of credit.

The Credit Agreement contains various covenants and restrictive provisions and requires maintenance of financial covenants as follows:

- an interest coverage ratio (as defined in the Credit Agreement) of not less than 3.00 to 1.00; and
- a total leverage ratio (as defined in the Credit Agreement) of not greater than 3.00 to 1.00. On April 6, 2015, we entered into an amendment to the Credit Agreement that increased this leverage ratio to 3.50 to 1.00.

On September 30, 2015, our total leverage ratio exceeded the threshold of 3.50 to 1.00. We were in compliance with all other covenants at that time. We advised the lenders under the Credit Agreement when we became aware of the potential covenant breach, and on October 19, 2015, we entered into a limited waiver to the Credit Agreement whereby the lenders waived any default or right to exercise any remedy as a result of our failure to be in compliance with the leverage covenant for the fiscal quarter ended September 30, 2015. As consideration for the waiver, we agreed to not make any repurchases of or quarterly cash distributions on our common units prior to November 13, 2015 and to limit the aggregate amount of advances made under the Credit Agreement between October 19, 2015 and November 13, 2015 to no more than $25 million. On November 12, 2015, we entered into a second limited waiver to the Credit Agreement which extended the period of the waiver granted until November 20, 2015.

On November 18, 2015, we, PNC Bank, National Association, as agent, and the lenders entered into the Second Amendment to the Credit Agreement (the "Second Amendment"). The Second Amendment, among other things, forgoes the application of the total leverage ratio and interest coverage ratio covenants until the earlier of June 30, 2018 or such time as our total leverage ratio is less than 3.50 to 1.00 as of the end of any two consecutive fiscal quarters (the "ratio compliance date"). Prior to the ratio compliance date, we will be subject to the following covenants and restrictions:

- the $350 million total aggregate commitment under the Credit Agreement will be reduced in an amount equal to the net proceeds of any notes offerings we may make in the future;
- we will be required to maintain at least $25 million of excess availability (as defined in the Credit Agreement) under the Credit Agreement; and
- we will be required to generate consolidated EBITDA in certain minimum amounts beginning with the quarter ending December 31, 2015 and rolling forward thereafter.

In addition, the Second Amendment increases the interest rates applicable to borrowings under the Credit Agreement to either, (at our option) (i) LIBOR plus 4.25% or (ii) the base rate plus 3.25%. The Second Amendment also provides for the following covenants and restrictions:

- our subsidiaries will be restricted from making distributions to us (to permit us to make distributions to unitholders) if, after giving pro forma effect to such distribution, our total leverage ratio would be greater than or equal to 4.00 to 1.00 or the excess availability under the Credit Agreement would be less than the greater of $43.75 million or 12.5% of the total aggregate commitments;
- we will be restricted from entering into certain substantial acquisition or merger agreements with third-party businesses or making certain other investments;
- through March 31, 2019, our capital expenditures for growth and maintenance will be restricted and may not exceed certain amounts per quarter;

At December 31, 2015, we were in compliance with our loan covenants and had undrawn availability under the Credit Facility totaling $39.1 million. At December 31, 2015, our outstanding borrowings under the Credit Agreement bore interest at a weighted-average rate of 5.08%.

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Cash Flow Summary

The table below summarizes our cash flows for the years ended December 31, 2015, 2014 and 2013.

	Year Ended December 31,		
	2015	2014	2013
	($ in thousands)		
Cash flows from operating activities	$47,325	$86,161	$58,036
Cash flows from investing activities	$(33,674)	$(88,172)	$(38,009)
Cash flows from financing activities	$343	$6,720	$(19,327)
Cash and cash equivalents at beginning of period	$6,876	$2,167	$1,467
Cash and cash equivalents at end of period	$20,870	$6,876	$2,167

Operating Cash Flows

Net cash provided by operating activities has generally trended the same as our net income adjusted for non-cash items such as depreciation, depletion and amortization, equity-based compensation, amortization of deferred financing costs, project termination costs, and unrealized losses on derivative instruments. The changes in our operating assets and liabilities were also significantly impacted by lower accounts receivable balances resulting from lower sales of sand and fuel in 2015, a build-up of inventories in 2015, lower accounts payables and accrued liabilities balances due to lower cost of fuel in 2015, and higher spending for prepaid railcar lease assets in 2014.

Investing Cash Flows

As a result of the current market conditions, we had significantly curtailed our capital expenditures for 2015, spending only $35.5 million for the full year 2015 compared to $77.9 million in 2014.

Financing Cash Flows

The main categories of our financing cash flows can be summarized as follows:

	Year Ended December 31,		
	2015	2014	2013
	($ in thousands)		
Proceeds from IPO, net of offering costs	$—	$—	$116,574
Net debt proceeds (payments)	79,160	127,874	(71,523)
Distributions to owners	(74,351)	(112,992)	(49,167)
Distribution to Direct Fuels' owners	—	—	(11,500)
Other	(4,466)	(8,162)	(3,711)
Total	$343	$6,720	$(19,327)

The most significant differences in our financing cash flows came about as a result of our May 2013 IPO. Not only did we receive $116.6 million in net proceeds (after exercise of the overallotment and payment of offering costs), but we were able to reduce our overall debt amounts and paid a one-time distribution to Direct Fuels' prior owners in 2014 in relation to our purchase of Direct Fuels in May 2013. Distributions to unitholders decreased in 2015 due to non-availability of distributable cash flow beginning in the third quarter of 2015. We did not pay distributions to our unitholders for third quarter of 2015, and we will not pay distributions for the fourth quarter of 2015.

Management Incentive Plans

Effective May 14, 2013, we established long-term incentive plans for our employees, directors, and consultants. These plans include the issuance of restricted and phantom units which are dilutive to common unit holders.

Contingencies

In the opinion of management, there are no contingencies that are likely to have a material adverse impact on our financial condition, liquidity or reported results.

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Contractual Obligations

We have long-term contractual obligations that are required to be settled in cash. The amounts of our minimum contractual obligations as of December 31, 2015 were as follows:

	Payments Due By Period				
	Total	< 1 Year	1 - 3 Years	3 - 5 Years	> 5 Years
	($ in thousands)				
Long-term debt (1)	$380,922	$16,265	$31,599	$333,058	$—
Railcar leases (2)	547,011	59,161	117,948	124,526	245,376
Other operating leases (3)	6,458	1,607	1,489	588	2,774
Purchase commitments (4)	168,103	27,556	47,893	43,849	48,805
Minimum royalty payments (5)	2,860	230	460	460	1,710
Total	$1,105,354	$104,819	$199,389	$502,481	$298,665

(1) Assumes balances outstanding as of 12/31/15 will be paid at maturity and includes interest using interest rates in effect at 12/31/15.

(2) Includes minimum amounts payable under various operating leases for railcars as well as estimated costs to transport leased railcars from the manufacturer to our site for initial placement in service.

(3) Includes lease agreements for land, facilities and equipment.

(4) Includes minimum amounts payable under a business acquisition agreement, long-term rail transportation agreements, and other purchase commitments.

(5) Represents minimum royalty payments for various sand mining locations. The amounts paid will differ based on amounts extracted.

Off-Balance Sheet Arrangements

As of December 31, 2015, our Sand segment had outstanding letters of credit totaling $8.0 million that support various railcar lease obligations as well as reclamation obligations for sand mining properties. We do not believe these letters of credit could have a material effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures, or capital resources.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions. These estimates and assumptions affect the amounts reported in our Consolidated Financial Statements and notes. We base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Actual results may differ from these estimates, and estimates are subject to change due to modifications in the underlying conditions or assumptions. Currently, we do not foresee any reasonably likely changes to our current estimates and assumptions that would materially affect amounts reported in the financial statements and notes. Below are expanded discussions of our more significant accounting policies, estimates and judgments, i.e., those that reflect more significant estimates and assumptions used in the preparation of our financial statements. See Note 2 to our Consolidated Financial Statements for details about additional accounting policies and estimates made by management.

Depreciation and Depletion Methods and Estimated Useful Lives of Property, Plant and Equipment

In general, depreciation is the systematic and rational allocation of an asset's cost, less its residual value (if any), to the periods it benefits. We depreciate all of our property, plant and equipment other than mineral reserves using the straight-line method, which results in depreciation expense being incurred evenly over the life of an asset. Our estimate of depreciation expense incorporates management assumptions regarding the useful economic lives and residual values of our assets. When we place our assets in-service, we believe such assumptions are reasonable; however, circumstances may develop that would cause us to change these assumptions, which would change our depreciation amounts prospectively. Examples of such circumstances include:

- changes in laws and regulations that limit the estimated economic life of an asset;
- changes in technology that render an asset obsolete;
- changes in expected salvage values; or

- significant changes in the forecast life of proved reserves of applicable oil- and gas-producing basins, if any.

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Our mineral reserves are initially recognized at cost and are depleted using the units-of-production method. Under this method, we compute the depletion expense by multiplying the number of tons of sand produced by a rate arrived at by dividing the physical units of sand produced during the period by the total estimated sand reserves volume at the beginning of the period.

Asset Retirement Obligations

We follow the provisions of Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") 410-20, Asset Retirement Obligations, which generally applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or the normal operation of owned or leased long-lived assets.

We recognize the fair value of any liability for conditional asset retirement obligations, including environmental remediation liabilities when incurred, which is generally upon acquisition, construction or development and/or through the normal operation of our mineral reserves, if sufficient information exists to reasonably estimate the fair value of the liability. These obligations generally include the estimated net future costs of dismantling, restoring and reclaiming operating mines and related mine sites, in accordance with federal, state and local regulatory requirements. The estimated liability is based on historical industry experience in reclaiming mine sites, including estimated economic lives, external estimates as to the cost to bringing back the land to federal and state regulatory requirements. In calculating this estimate, we use a discount rate reflecting management's best estimate of our credit-adjusted risk-free rate.

The liability is accreted over time through periodic charges to earnings. In addition, the asset retirement cost is capitalized as part of the asset's carrying value and amortized over the life of the related asset. Reclamation costs are periodically adjusted to reflect changes in the estimated present value resulting from the passage of time and revisions to the estimates of either the timing or amount of the reclamation and abandonment costs. The reclamation obligation is based on when spending for an existing environmental disturbance is expected to occur. If the asset retirement obligation is settled for other than the carrying amount of the liability, a gain or loss will be recognized on settlement. We review, on an annual basis, unless otherwise deemed necessary, the reclamation obligation at each mine site in accordance with ASC guidance for accounting for reclamation obligations.

Impairment of Goodwill

In accordance with FASB ASC 350, Intangibles – Goodwill and Other, goodwill is tested no less than annually unless indicators of impairment exist in interim periods. The impairment test uses a two-step process, which is performed at the reporting unit level. Step one compares the fair value of the reporting unit to its carrying value. We calculate the fair value using the enterprise value-market capitalization approach. This approach uses estimates and assumptions that are believed to be reasonable at the time of the calculation. If the carrying value exceeds the fair value, there is a potential impairment and step two must be performed. Step two compares the carrying value of the reporting unit's goodwill to the implied fair value (i.e., the fair value of the reporting unit less the fair value of the unit's assets and liabilities, including identifiable intangible assets). If the carrying value of goodwill exceeds its implied fair value, we record the excess as an impairment charge to earnings. We performed our annual assessment of goodwill in the fourth quarter of 2015, and determined during step one that the fair value of the reporting unit (our Fuel segment) exceeds its carrying value. Therefore, it was not necessary to perform step two of the analysis.

Impairment of Long-Lived Assets

In accordance with FASB ASC 360, long-lived assets are reviewed for impairments whenever events or changes in circumstances indicate that the related carrying amount may not be recoverable. If circumstances require a long-lived asset to be tested for possible impairment, we first compare undiscounted cash flows expected to be generated by an asset to the carrying value of the asset. If the carrying value of the long-lived asset is not recoverable on an undiscounted cash flow basis, impairment is recognized to the extent that the carrying value exceeds its fair value. Assets to be disposed of are reported at the lower of the carrying amount or fair value less selling costs. The recoverability of intangible assets subject to amortization is evaluated whenever events or changes in circumstances indicate that the carrying value of the assets may not be recoverable.

Business Combinations

We use the acquisition method of accounting for acquired businesses. Under the acquisition method, our financial statements reflect the operations of an acquired business starting from the completion of the acquisition. The assets acquired and liabilities assumed are recorded at their respective estimated fair values at the date of the acquisition. Any excess of the purchase price over the estimated fair values of the identifiable net assets acquired is recorded as goodwill. Significant judgment is often required in estimating the fair value of assets acquired, particularly intangible assets. As a result, in the case of significant or complex acquisitions, we normally obtain the assistance of a third-party valuation specialist in estimating fair values of tangible and intangible assets. The fair value estimates are based on available historical information and on expectations and assumptions about the future, considering the perspective of marketplace participants. While we believe those expectations and assumptions are reasonable, they are inherently uncertain. Unanticipated market or macroeconomic events and circumstances may occur, which could affect the accuracy or validity of the estimates and assumptions.

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Accounting for Contingencies

Our financial results may be affected by judgments and estimates related to loss contingencies. Litigation contingencies may require significant judgment in estimating amounts to accrue. We accrue liabilities for litigation contingencies when such liabilities are considered probable of occurring and the amount is reasonably estimable.

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. We use derivative financial instruments and commodity instruments, where appropriate, to manage these risks. As a matter of policy, we do not engage in trading or speculative transactions. We also do not designate these derivatives for hedge accounting under FASB ASC 815, Derivatives and Hedging, even though these hedging transactions serve the same risk management purposes whether designated for hedge accounting treatment or not. We record the fair values of derivatives on our consolidated balance sheets, with any changes in these fair values reflected in current earnings on our consolidated statements of operations.

Commodity Price Risks

We are exposed to market risk with respect to the pricing that we receive for our sand production. Realized pricing for sand is primarily driven by a combination of take-or-pay contracts, fixed volume, and efforts-based agreements in addition to sales on the spot market. Prices under all of our supply agreements are generally fixed and are subject to adjustment, within limitations, in response to certain cost increases. However, the current market conditions have dictated that most of our pricing be determined on a spot basis. We do not enter into commodity price hedging agreements with respect to sand production.

We are also exposed to market risk with respect to the prices we charge for refined fuels products and that we pay for transmix, wholesale fuel and other feedstocks. Realized margins for our refined fuel products are determined by the relationship between the prices charged for fuel and the prices paid for transmix, wholesale fuel, and other feedstocks. We purchase transmix, wholesale fuel and other feedstocks based on several different regional price indices, the most important of which are the Platt's Gulf Coast gasoline and diesel price postings. The costs of these purchases are generally set on the day of purchase. We typically sell fuel products within seven to ten days of supply purchases at then prevailing market prices. If the market price for our fuel products declines during this period or generally does not increase commensurate with any increases in supply and processing costs, our margins will fall and the amount of cash available for distribution will decrease. In addition, because we value our inventory at the lower of cost or market value, if the market value of our inventory were to decline to an amount less than our cost, we would record a write-down of inventory and a non-cash charge to cost of sales. In a period of declining prices for transmix or refined products, our inventory valuation methodology may result in decreases in reported net income.

We utilize financial hedging arrangements (mainly futures traded on the New York Mercantile Exchange) to hedge a portion of our gasoline and diesel inventory, which reduces commodity price exposure on some of these activities. We record these commodity derivatives at fair value on the consolidated balance sheet with resulting gains and losses reflected in cost of fuel as reported in the consolidated statements of operations. We derive fair values principally from published market quotes. The precise level of open position derivatives is dependent on inventory levels, expected inventory purchase patterns, and market price trends.

A hypothetical $0.01 increase or decrease in the average gross margin between the price we charge for fuel and its cost would have changed our fuel segment operating income by $2.4 million for the year ended December 31, 2015.

Interest Rate Risk

We are exposed to fluctuations in interest rates charged on our variable rate debt. We enter into certain interest rate swap agreements in accordance with our risk management strategy. During 2013, we entered into interest rate swap agreements that will effectively convert $70 million notional amount of our variable rate debt to a fixed rate, effective October 14, 2014. We account for the interest rate swap agreements on a mark-to-market basis through current earnings even though they were not acquired for trading purposes. We recorded aggregate realized and unrealized losses of $0.8 million in 2015 and 2014.

A hypothetical increase or decrease in interest rates by 100 basis points would have changed the interest incurred on our variable rate debt by $11.1 million for the year ended December 31, 2015.

Customer Credit Risk

We are subject to risks of loss resulting from nonpayment or nonperformance by our customers. We examine the creditworthiness of third-party customers to whom we extend credit and manage exposure to credit risk through credit analysis, credit approval, credit limits, and monitoring procedures. Our top three customer balances accounted for 35% and 48% of our net accounts receivable at December 2015 and 2014, respectively.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

EMERGE ENERGY SERVICES LP
INDEX TO FINANCIAL STATEMENTS

Emerge Energy Services LP Consolidated Financial Statements:

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors of Emerge Energy Services GP LLC, as General Partner of Emerge Energy Services LP and the Partners of Emerge Energy Services LP
Southlake, Texas

We have audited the accompanying consolidated balance sheets of Emerge Energy Services LP (the "Partnership") as of December 31, 2015 and 2014 and the related consolidated statements of operations, partners' equity, and cash flows for each of the three years in the period ended December 31, 2015. 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 audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Emerge Energy Services LP at December 31, 2015 and 2014, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Emerge Energy Services LP's internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated February 29, 2016 expressed an unqualified opinion thereon.

/s/ BDO USA, LLP
Dallas, Texas
February 29, 2016

EMERGE ENERGY SERVICES LP
CONSOLIDATED BALANCE SHEETS
($ in thousands, except unit data)

	December 31, 2015	2014
ASSETS		
Current assets:		
Cash and cash equivalents	$20,870	$6,876
Trade and other receivables, net	37,202	75,708
Inventories	42,618	32,278
Prepaid expenses and other current assets	11,744	9,262
Total current assets	112,434	124,124
Property, plant and equipment, net	233,630	238,657
Intangible assets, net	31,447	31,158
Goodwill	29,264	29,264
Other assets, net	13,273	8,924
Total assets	$420,048	$432,127
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable	$18,427	$21,341
Accrued liabilities	18,401	24,411
Current portion of long-term debt	—	53
Current portion of capital lease liability	—	930
Total current liabilities	36,828	46,735
Long-term debt, net of current portion	295,938	217,023
Business acquisition obligation, net of current portion	7,772	10,737
Capital lease liability, net of current portion	—	57
Other long-term liabilities	4,732	2,386
Total liabilities	345,270	276,938
Commitments and contingencies		
Partners' equity:		
General partner	—	—
Limited partner common units (issued and outstanding 24,119,972 units and 23,718,961 units as of December 31, 2015 and December 31, 2014, respectively)	74,778	155,189
Total partners' equity	74,778	155,189
Total liabilities and partners' equity	$420,048	$432,127

See accompanying notes to consolidated financial statements.

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EMERGE ENERGY SERVICES LP
CONSOLIDATED STATEMENTS OF OPERATIONS
($ in thousands, except per unit data)

	Year Ended December 31,		
	2015	2014	2013
Revenues (1)	$711,639	$1,111,254	$873,255
Operating expenses:			
Cost of goods sold (excluding depreciation, depletion and amortization) (1)	635,825	950,006	767,911
Depreciation, depletion and amortization	28,441	24,803	20,828
Selling, general and administrative expenses	33,119	38,723	26,835
Project terminations	10,652	—	—
IPO transaction-related costs	—	—	10,966
Total operating expenses	708,037	1,013,532	826,540
Income from operations	3,602	97,722	46,715
Other expense (income):			
Interest expense, net	12,554	7,365	10,396
Loss on extinguishment of debt	—	—	907
Other expense (income)	(45)	640	(144)
Total other expense	12,509	8,005	11,159
Income (loss) before provision for income taxes	(8,907)	89,717	35,556
Provision for income taxes	504	638	386
Net income (loss)	(9,411)	89,079	35,170
Less Predecessor net income before May 14, 2013	—	—	13,124
Post-IPO net income (loss)	$(9,411)	$89,079	$22,046
Earnings (loss) per common unit (basic) (2)	$(0.39)	$3.70	$0.92
Earnings (loss) per common unit (diluted) (2)	$(0.39)	$3.70	$0.92
Weighted average number of common units outstanding including participating securities (basic) (2)	23,973,850	24,070,418	24,015,562
Weighted average number of common units outstanding (diluted) (2)	23,973,850	24,076,437	24,021,957
(1) Fuel revenues and cost of goods sold include excise taxes and similar taxes	$50,939	$50,116	$47,007
(2) See Note 15			

See accompanying notes to consolidated financial statements.

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EMERGE ENERGY SERVICES LP
CONSOLIDATED STATEMENTS OF PARTNERS' EQUITY
($ in thousands)

	Limited Partner Common Units	General Partner (non-economic interest)	Predecessor	Total Partners' Equity
Balance at December 31, 2012	$(79)	$—	$9,496	$9,417
Net income (loss) from January 1, 2013 through May 13, 2013	(97)	—	13,221	13,124
Balance at May 13, 2013	(176)	—	22,717	22,541
Proceeds from IPO, net of offering costs	116,220	—	—	116,220
Contribution of Predecessor net assets in exchange for common units	22,717	—	(22,717)	—
Common units issued for business acquired	53,721	—	—	53,721
Equity-based compensation expense	5,734	—	—	5,734
Distribution to prior owners including over commitment proceeds	(19,628)	—	—	(19,628)
Redemption of original limited partner interest	(2)	—	—	(2)
Distributions paid	(29,539)	—	—	(29,539)
Distribution equivalent rights accrued	(372)	—	—	(372)
Net income from May 14, 2013 through December 31, 2013	22,046	—	—	22,046
Balance at December 31, 2013	170,721	—	—	170,721
Net income	89,079	—	—	89,079
Equity-based compensation	9,194	—	—	9,194
Distributions paid	(112,651)	—	—	(112,651)
Distribution equivalent rights accrued	(1,164)	—	—	(1,164)
Recovery of short swing profit	10	—	—	10
December 31, 2014	155,189	—	—	155,189
Net income (loss)	(9,411)	—	—	(9,411)
Equity-based compensation	3,654	—	—	3,654
Distributions paid	(74,337)	—	—	(74,337)
Distribution equivalent rights accrued	(632)	—	—	(632)
Recovery of short swing profit	315	—	—	315
Balance at December 31, 2015	$74,778	$—	$—	$74,778

See accompanying notes to consolidated financial statements.

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EMERGE ENERGY SERVICES LP
CONSOLIDATED STATEMENTS OF CASH FLOWS
($ in thousands)

	Year Ended December 31,		
	2015	2014	2013
Cash flows from operating activities:			
Net income (loss)	$(9,411)	$89,079	$35,170
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	28,441	24,803	20,828
Equity-based compensation expense	3,532	9,042	5,734
Project termination costs - non-cash portion	10,345	—	—
Interest paid in-kind	—	—	3,202
Loss on extinguishment of debt	—	—	907
Provision for doubtful accounts	1,541	253	190
Loss (gain) on disposal of assets	146	8	755
Amortization of debt discount/premium and deferred financing costs	1,244	969	937
Loss on termination of sand supply agreement	—	689	—
Unrealized loss on derivative instruments	(419)	669	(247)
Other non-cash	110	38	(244)
Changes in operating assets and liabilities, net of business acquired:			
Restricted cash and equivalents	—	6,188	(6,188)
Accounts receivable	36,938	(26,328)	(17,374)
Inventories	(10,341)	9,044	(11,451)
Prepaid expenses and other current assets	(1,861)	(5,104)	5,064
Accounts payable and accrued liabilities	(8,592)	(14,971)	20,871
Other assets	(4,348)	(8,218)	(118)
Net cash provided by operating activities	47,325	86,161	58,036
Cash flows from investing activities:			
Purchases of property, plant, equipment and intangible assets	(35,474)	(77,884)	(21,369)
Business acquisitions, net of cash acquired	—	(11,000)	(16,687)
Proceeds from disposals of assets	1,787	335	35
Collection of notes receivable	13	377	12
Net cash used in investing activities	(33,674)	(88,172)	(38,009)
Cash flows from financing activities:			
Proceeds from IPO including over commitment	—	—	122,221
IPO offering costs	—	—	(5,647)
Proceeds from line of credit borrowings	284,200	371,657	134,180
Repayments of line of credit borrowings	(204,000)	(243,603)	(61,619)
Repayment of Direct Fuels' debt	—	—	(21,673)
Proceeds from other long-term debt	—	—	81
Repayments of other long-term debt	(53)	(180)	(118,640)
Distributions to unitholders	(74,351)	(112,992)	(29,539)
Distributions to Predecessor owners	—	—	(19,628)
Pre-IPO dividends paid (Direct Fuels)	—	—	(11,500)
Payment of business acquisition obligation	(2,253)	—	—

Payment of financing costs	(2,528)	(2,342)	(3,709)
Payments on capital lease obligation	(987)	(5,831)	(3,507)
Repayments of other debt	—	—	(345)
Redemption of general partner interest	—	—	(2)
Recovery of short swing profit	315	11	—
Net cash provided by (used in) financing activities	343	6,720	(19,327)
Cash and cash equivalents:			
Net increase (decrease)	13,994	4,709	700
Balance at beginning of year	6,876	2,167	1,467
Balance at end of year	$20,870	$6,876	$2,167

See accompanying notes to consolidated financial statements.

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EMERGE ENERGY SERVICES LP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND BASIS OF PRESENTATION

Organization

Emerge Energy Services LP ("Emerge") is a Delaware limited partnership that completed its initial public offering ("IPO") on May 14, 2013 to become a publicly traded partnership. The combined entities of Superior Silica Sands LLC ("SSS"), a Texas limited liability company, Allied Energy Company LLC ("AEC"), an Alabama limited liability company, and Emerge Energy Services Operating LLC ("Emerge Operating"), a Delaware limited liability company, represent the predecessor for accounting purposes (the "Predecessor") of Emerge.

References to the "Partnership," "we," "our" or "us" when used for dates or periods ended prior to the IPO, refer collectively to the Predecessor. References to the "Partnership," "we," "our" or "us" when used for dates or periods ended on or after the IPO, refer collectively to Emerge and all of its subsidiaries, including Direct Fuels LLC ("Direct Fuels"), which was acquired in a business combination concurrent with our IPO.

We are a growth-oriented energy services company engaged in: (i) the business of mining, producing, and distributing silica sand that is a key input for the hydraulic fracturing of oil and gas wells; and, (ii) the business of distributing refined motor fuels, refining transportation mixture ("transmix") and biodiesel, operating bulk motor fuel storage terminals, and providing complementary services. We report silica sand activities through the Sand segment and motor fuel operations through the Fuel segment. We report items of income (if any) and expense that cannot be directly associated with the Sand and Fuel segments as "corporate."

The Sand segment conducts mining and processing operations from facilities located in Wisconsin and Texas. In addition to mining and processing silica sand for the oil and gas industry, the Sand segment sells its product for use in building products and foundry operations. The Fuel segment operates transmix processing facilities located in the Dallas-Fort Worth area and in Birmingham, Alabama. The Fuel segment also offers third-party bulk motor fuel storage and terminal services, biodiesel refining, sale and distribution of wholesale motor fuels, reclamation services (which consists primarily of cleaning bulk storage tanks used by other petroleum terminal and others) and blending of renewable fuels.

Initial Public Offering of Emerge Energy Services LP

On May 8, 2013, the Partnership priced an initial public offering of 7,500,000 limited partner common units ("common units") at a price of $17.00 per common unit ($15.85 per common unit, net of underwriting discounts and structuring fee). The IPO was conducted pursuant to a registration statement on Form S-1 originally filed on March 22, 2013, as amended (Registration No. 333-187487) that was declared effective by the U.S. Securities and Exchange Commission ("SEC") on May 8, 2013. On May 20, 2013, the underwriters exercised their option to purchase an additional 209,906 common units. The net proceeds from the IPO of $122.2 million (including net proceeds of $3.3 million from the exercise of the underwriters' over-allotment option), after deducting the underwriting discount and the structuring fee, were used to: (i) repay existing subsidiary debt, in the amount of $87.6 million, (ii) pay offering expenses of $10.6 million, (iii) pay and fund cash-based compensation awards to senior management of $8.9 million, (iv) provide the Partnership with working capital of $11.5 million, (v) provide a distribution to pre-IPO equity holders of $3.3 million ($2.6 million to predecessors' owners and $0.7 million to Direct Fuels' owners as part of the original purchase price), and (vi) pay certain prepaid items of $0.3 million.

Secondary Offering

On June 20, 2014, we and our general partner, along with certain selling unitholders named therein (the "Selling Unitholders") entered into an Underwriting Agreement with underwriters named therein (the "Underwriters"), with respect to the offer and sale (the "Secondary Offering") by the Selling Unitholders of 3,515,388 common units at a price to the public of $109.06 per common unit ($105.2429 per common unit, net of underwriting discounts and commissions). On June 25, 2014, the Selling Unitholders completed the Secondary Offering. We did not receive any proceeds from the Secondary Offering. Pursuant to the Underwriting Agreement, the Selling Unitholders also granted the Underwriters an option for a period of 30 days to purchase up to an additional 527,307 common units on the same terms, and on July 18, 2014, the Underwriters partially exercised the option to purchase 165,635 common units. Following the closing of this transaction and as of December 31, 2015, Insight Equity Management Company LLC and its affiliated investment funds and its controlling equity owners (collectively "Insight Equity") held approximately 35% of all of our outstanding common units.

Basis of Presentation and Consolidation

Prior to completion of our IPO, Superior Silica Holdings LLC and AEC Holdings LLC, which together constitute our Predecessor for accounting purposes, were under the common control of a private equity fund managed and controlled by Insight Equity. As

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a result, their contribution to the Partnership was recorded as a combination of entities under common control, whereby the assets contributed and liabilities assumed are recorded based on their historical carrying values. After the contribution of the Predecessor's business and net assets on May 14, 2013, we have retroactively reported our financial statements to include the historical results of our Predecessor. We accounted for the purchase of Direct Fuels under Financial Accounting Standards Board Accounting Standards Codification (FASB ASC), Statement 805, Business Combinations, whereby the net assets acquired are recorded at fair value on the date of acquisition. The acquisition of Direct Fuels was accounted for as a business combination using the acquisition method of accounting. The financial position and results of operations of Direct Fuels are included in our consolidated financial statements from and as of the date of acquisition. We acquired Direct Fuels to expand our operations, gain new customers, improve earnings, and increase our markets through a larger geographical presence. After completing the acquisition on May 14, 2013, the Partnership owned 100% of Direct Fuels. We funded the acquisition with a combination of cash, issuance of common units and assumption of debt.

For periods prior to our IPO, the accompanying consolidated financial statements and related notes present the historical accounts of the Predecessor. To the extent they relate to periods prior to the IPO, the results are not necessarily indicative of the actual results of operations that might have occurred if we had operated as a combined entity during that pre-IPO period.

These consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States (“GAAP”) and include the accounts of all of our subsidiaries. All significant intercompany transactions and balances have been eliminated in consolidation.

Liquidity Considerations

During periods of economic slowdown and long-term reductions in oil and natural gas prices, oil and natural gas exploration and production companies often reduce their oil and natural gas production rates and also reduce capital expenditures and defer or cancel pending projects, which results in decreased demand for our frac sand. Beginning in late 2014, the market prices for crude oil and refined products began a steep and protracted decline which has continued throughout 2015. This has greatly impacted the demand for frac sand as drilling and completion of new oil and natural gas wells has been significantly curtailed in North America. As a result, we are experiencing continued, significant downward pressure on pricing while rig counts and oil prices continue to decline. We expect that drilling and well completion activity levels, based on indications from our customers and other industry sources, will be further reduced in the upcoming year. This decline may result in weak frac sand demand, and put further pressure on frac sand prices, for an extended period of time.

Our operating results, cash flows and liquidity were negatively affected in 2015 by the aforementioned decline in oil and natural gas prices. Companies servicing the oil and natural gas industry experienced reduced access to credit and capital markets as compared to previous years, a trend which we expect to continue in 2016. Sustained downward pressure on oil and natural gas prices may further exacerbate these challenges and negatively impact our liquidity position in 2016. While cash flows from our operating activities are a key contributor to our liquidity, we are increasingly dependent on borrowings under our revolving line of credit to fund our cash requirements. Although we were in compliance with our loan covenants at December 31, 2015, we may not meet the requirements of our covenants throughout 2016 due to the continued deterioration of the oil and gas market generally, and the frac sand market in particular.

We have adopted new strategies to address our decreased liquidity and position the company to weather this protracted industry downturn and return quickly to profitability when improved market opportunities return. In order to conserve liquidity and respond to the industry downturn, we have become increasingly focused on prudently reducing costs while maintaining our ability to quickly respond to increased demand when the market begins to recover in the future. As the market trends have had the most impact on our frac sand business, we have concentrated our efforts on the Sand segment. Our liquidity strategies include, but are not limited to, (i) reducing costs in numerous areas across our Sand segment and Fuel segment, (ii) increasing the margins in our Sand segment and Fuel segment with new product offerings and projects, (iii) exploring strategic and alternative financing arrangements such as asset sales and capital infusions, (iv) delaying capital investments which do not produce short-term return on investment, (v) negotiating modifications to our credit agreement to reduce our debt service obligations and reset covenants based on forecasted liquidity requirements, and (vi) negotiating price concessions and purchase commitment concessions from our major vendors, such as rail transportation providers, mine operators, transload facilities operators, and professional services providers.

We cannot assure you that we would be able to successfully execute our strategies described above, or obtain alternative financing, if necessary, on commercially reasonable terms or at all, or that implementing these strategies would allow us to meet our debt obligations and capital requirements or that these actions would be permitted under the terms of our various debt instruments.

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2. SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reported period. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results could differ from those estimates, and such differences could be material.

Restricted Cash and Equivalents

We were required under agreements with our chief executive officer (“CEO”) and an officer in our Sand segment (the “Sand Officer”) to establish and maintain Rabbi Trusts used to fund deferred compensation as described in the agreements. Restricted cash and equivalents were invested in short-term instruments at market rates; therefore the carrying values approximated fair value. In May 2014, all funds in the Rabbi Trusts were distributed to our CEO and Sand Officer and the Rabbi Trusts were terminated.

Accounts Receivable and Allowance for Doubtful Accounts

Trade accounts receivable are recognized at their invoiced amounts and do not bear interest. We maintain an allowance for doubtful accounts for estimated losses resulting from the inability of our customers to make required payments. We estimate our allowances for doubtful accounts based on specifically identified amounts that are believed to be uncollectible. If the financial condition of our customers were to deteriorate, resulting in an impairment of their ability to make payments, additional allowances for doubtful accounts might be required. After all attempts to collect a receivable have failed, the receivable is written off against the allowance for doubtful accounts. The allowance for doubtful accounts was $1.9 million at December 31, 2015, and $0.4 million at December 31, 2014.

Inventories

Finished goods inventories consist of dried sand and refined motor fuel products. Finished sand costs include all transportation costs necessary to transport the finished sand to the point of sale. All inventories are stated at the lower of cost or market using the average cost method. Raw materials inventories consist of unprocessed sand, transmix feedstock, and supplies. Raw materials inventories are stated at the lower of cost or market using the average cost method. Wet sand is included in work in process. Overhead in our Sand segment is capitalized at an average rate per unit based on actual costs incurred. Our Fuel segment does not capitalize overhead to its refined transmix inventory because turnover is high and the quantities are generally modest in comparison to our finished fuel inventories we purchase from third party refiners.

Accounting for Renewable Identification Numbers

The Fuel segment is required to comply with federal laws that regulate biofuels and renewable identification numbers (“RINs”). RINs are serial numbers assigned to biofuels for the purpose of tracking its production, use, and trading as required by the U.S. Environmental Protection Agency (the “EPA”) under its Renewable Fuel Standard implemented according to the Energy Policy Act of 2005. Generally, companies that refine petroleum-based fuels are obligated to meet certain quotas based on the volume of fuel they introduce into the marketplace. We are required to satisfy these obligations to the extent previously non-certified fuels are included or introduced into transmix feedstock. We account for these direct obligations as a liability until satisfied. As of December 31, 2015 and 2014, accrued liabilities include $0.5 million and $0.6 million, respectively, for obligations under the Energy Policy Act of 2005.

The Fuel segment routinely purchases ethanol for blending with gasoline. To a lesser extent, the Fuel segment purchases biodiesel for blending with diesel. We have the option to purchase these biofuels with or without RINs, but most biofuels are only available for purchase with RINs. The price suppliers charge to us for biofuels with RINs is somewhat higher than a price that would be charged for product without RINs. We generally purchase the biofuels with RINs. We account for RINs in a manner similar to the purchase of conventional fuels. On a monthly basis, we sell most of our RINs under a contractual arrangement with a major refiner. For RINs that remain unsold at the end of an accounting period, we value this asset at an amount that approximates net realizable value, recording the offset as a reduction in cost of goods sold. When these RINs are sold, we record the sale as a reduction of costs of goods sold instead of additional revenue, effectively offsetting the charge to cost of goods sold when the RINs asset is relieved. As of December 31, 2015 and 2014, prepaid expenses and other current assets include RINs valued at $1.4 million and $1.0 million, respectively.

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Property, Plant and Equipment, net

We recognize purchases of property, plant and equipment at cost, including any capitalized interest. Maintenance, repairs and renewals are expensed when incurred. Additions and significant improvements are capitalized. Disposals are removed at cost less accumulated depreciation and any gain or loss from dispositions is recognized in income. We capitalized $0 million, $0.6 million and $0 million of interest on construction of assets for the years ended December 31, 2015, 2014 and 2013, respectively.

Depreciation of property, plant and equipment other than mineral reserves is provided for on a straight-line basis over their estimated useful lives. We recognized $19.2 million, $15.2 million and $13.7 million of depreciation expense for the years ended December 31, 2015, 2014 and 2013, respectively.

Mineral reserves are initially recognized at cost, which approximates the estimated fair value as of the date of acquisition. The provision for depletion of the cost of mineral reserves is computed on the units-of-production method. Under this method, we compute the provision by multiplying the total cost of the mineral reserves by a rate arrived at dividing the physical units of sand produced during the period by the total estimated mineral resources at the beginning of the period. Depletion expense for the years ended December 31, 2015, 2014 and 2013 totaled $2.0 million, $1.2 million and $29 thousand, respectively.

Following are the estimated useful lives of our property, plant and equipment:

	Useful Lives (in Years)
Building and land improvements including assets under capital lease	10 – 39
Mineral reserves	N/A*
Tanks and equipment	7 – 40
Railroad and related improvements	20 – 40
Machinery and equipment	5 – 10
Plant equipment including assets under capital lease	5 – 7
Industrial vehicles	3 – 7
Furniture, office equipment and software	3 – 7
Leasehold improvements	3 – 5 or lease term, whichever is less

* Depletion calculated using units-of-production method

Impairment or Disposal of Long-Lived Assets

In accordance with FASB ASC 360-10-05, Impairment or Disposal of Long-Lived Assets, long-lived assets such as property, plant and equipment, and intangible assets subject to amortization are reviewed for impairments whenever events or changes in circumstances indicate that the related carrying amount may not be recoverable. If circumstances require a long-lived asset be tested for possible impairment, we first compare undiscounted cash flows expected to be generated by an asset to the carrying value of the asset. If the carrying value of the long-lived asset is not recoverable on an undiscounted cash flow basis, impairment is recognized to the extent that the carrying value exceeds its fair value. Assets to be disposed of are reported at the lower of the carrying amount or fair value less selling costs. The recoverability of intangible assets subject to amortization is also evaluated whenever events or changes in circumstances indicate that the carrying value of the assets may not be recoverable. In management's opinion, no impairment of long-lived assets exists at December 31, 2015 and 2014.

Intangible Assets Other Than Goodwill

Intangible assets consist of trade names, patents, customer relationships, supply and transportation arrangements, and non-compete agreements. Trade names are amortized on a straight-line basis over 15 years; patents are amortized on a straight line basis over 30 months, customer relationships are amortized using an accelerated amortization method over 15 years; supply and transportation arrangements are amortized using the straight-line method over varying periods up to 54 months, depending on the contract terms; and the non-compete agreements are amortized on a straight-line basis over the terms of the agreements.

We recognized $7.2 million, $8.4 million and $7.1 million of amortization expense for 2015, 2014 and 2013, respectively.

Goodwill

Goodwill is not amortized and represents the excess purchase price of the Direct Fuels acquisition over the estimated fair value of the net identifiable assets acquired. As of December 31, 2015 and 2014, goodwill is associated with our Fuel segment. In accordance with GAAP, we perform impairment testing of goodwill assets annually, or more frequently if indicators of impairment exist in interim periods. The impairment test for goodwill uses a two-step process, which is performed at the entity level (the reporting unit). Step one compares the fair value of the reporting unit to its carrying value. If the carrying value exceeds the fair value, there is a potential impairment and step two must be performed. Step two compares the carrying value of the reporting

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unit's goodwill to the implied fair value (i.e., the fair value of the reporting unit less the fair value of the unit's assets and liabilities, including identifiable intangible assets). If the carrying value of goodwill exceeds its implied fair value, we record the excess as an impairment charge to earnings.

We performed our annual assessment of goodwill in the fourth quarter of 2015, and determined during Step one that the fair value of the reporting unit (our Fuel segment) exceeds its carrying value. Therefore, it was not necessary to perform Step two of the analysis.

Railcar Freight Costs

The cost to transport leased railcars from the manufacturer to our site for initial placement in service is capitalized and amortized over the term of the lease (typically five to seven years). The non-current portion of these capitalized costs totaled $11.8 million and $8.3 million as of December 31, 2015 and 2014, respectively, and is included in “Other assets, net” on our Consolidated Balance Sheets

Derivative Instruments and Hedging Activities

We account for derivatives and hedging activities in accordance with FASB ASC 815, Derivatives and Hedging, which requires entities to recognize all derivative instruments as either assets or liabilities in the balance sheet at their respective fair values. For derivative instruments that do not qualify as an accounting hedge, changes in fair value of the assets and liabilities are recognized in earnings. Our policy is to not hold or issue derivative instruments for trading or speculative purposes.

Mining and Wet Sand Processing Agreement

In April 2014, a five-year contract with a sand processor (“Processor”) became effective to support our sand business in Wisconsin. Under this contract, the Processor financed and built a wet wash processing plant near our Wisconsin operations. As part of the agreement, the Processor wet washes our sand, creates stockpiles of washed sand and maintains the plant and equipment. During the term of the agreement the Processor will own the wet plant along with the equipment and other temporary structures used to support this activity. At the end of the five-year term of the agreement or following a default under the contract by the Processor, we have the right to take ownership of the wet plant and other equipment without charge. Subject to certain conditions, ownership of the plant and equipment will transfer to us at the expiration of the term. We accounted for the wet plant as a capital lease obligation. The original capitalized lease asset and corresponding capital lease obligation totaled $3.3 million.

Asset Retirement Obligations

We follow the provisions of FASB ASC 410-20, Asset Retirement Obligations, which generally applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or the normal operation of a long-lived asset. The standard requires us to recognize an estimated liability for costs associated with the future reclamation of sand mining properties, whether leased or owned, whenever we have a legal obligation to restore the site in the future.

A liability for the fair value of an asset retirement obligation with a corresponding increase to the carrying value of the related long-lived asset is recognized at the time the land is mined. The asset is depleted using the straight-line method, and the discounted liability is increased through accretion over the remaining life of the mine site.

The estimated liability is based on historical industry experience in abandoning mine sites, including estimated economic lives, external estimates as to the cost to bringing back the land to federal and state regulatory requirements. We have utilized a discounted rate reflecting management's best estimate of our credit-adjusted risk-free rate. Revisions to the liability could occur due to changes in the estimated costs, changes in the mine's economic life or if federal or state regulators enact new requirements regarding the abandonment of mine sites.

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Changes in the asset retirement obligations are as follows:

	Year Ended December 31,	
	2015	2014
	($ in thousands)	
Beginning balance	$2,386	$1,414
Additions	113	934
Accretion	80	38
Reclamation costs	(9)	—
Ending balance	$2,570	$2,386

Revenue Recognition

Our revenue is recognized when persuasive evidence of an arrangement exists, delivery of products has occurred, the sales price charged is fixed or determinable, and collectability is reasonably assured. This generally means that we recognize revenue when our products leave our facilities. Sand and fuel are generally transported via railcar or trucking companies hired by the customer.

We sell some of our Sand segment products under short-term price agreements or at prevailing market rates. A significant portion of our Sand segment revenues are realized through take-or-pay supply agreements with large oilfield services companies. The initial terms of these contracts expire between 2016 and 2021. These agreements define, among other commitments, the volume of product that our customers must purchase, the volume we must provide and the price that we will charge, as well as the rate that our customers will pay. Prices under these agreements are generally fixed and subject to adjustment, upward or downward, only for certain changes in published producer cost indices or market factors. With respect to the take-or-pay arrangements, if the customer is unable to carry forward minimum quantity deficiencies, we recognize Sand segment revenues to the extent of the minimum contracted quantity, assuming payment has been received or is reasonably assured. If deficiencies can be carried forward, receipts in excess of actual sales are recognized as deferred revenues until product is actually delivered or the right to carry forward minimum quantities expires.

We recognize Fuel segment revenue related to our terminals, reclamation, transportation services, and sales of motor fuels, net of trade discounts and allowances, in the reporting period in which the services are performed and motor fuel products are transferred from our terminals, title and risk of ownership pass to the customer, collection of the relevant receivable is probable, persuasive evidence of an arrangement exists and the sales price is fixed or determinable. Purchases and sales of fuel with the same counterparty that are entered into in contemplation of one another are considered to be a single nonmonetary transaction. Therefore, we record the net effect of such transactions as revenues.

Motor Fuel Taxes

We report excise taxes on motor fuels on a gross basis. For the years ended December 31, 2015, 2014 and 2013, excise taxes included in fuel revenues and cost of fuel totaled $50.9 million, $50.1 million and $47.0 million, respectively.

Equity-Based Compensation and Equity Incentive Plan

We recognize expenses for equity-based compensation based on the fair value method, which requires that a fair value be assigned to a unit grant on its grant date and that this value be amortized over the grantees' required service period. Restricted and phantom units have a fair value equal to the closing market price of the common units on the date of the grant. We amortize the fair value of the restricted and phantom units over the vesting period using the straight-line method. The fair value of a certain equity award to a key employee was determined using a Monte Carlo simulation. We calculate a forfeiture rate to estimate the equity-based awards that will ultimately vest based on types of awards and historical experience. For market-based awards, we make estimates as to the probability of the underlying market conditions being achieved and record expense if the conditions will probably be achieved.

Environmental Costs

Environmental costs are expensed or capitalized depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. We capitalize expenditures that extend the life of the related property or mitigate or prevent future environmental risk. We record liabilities when site restoration and environmental remediation, cleanup and other obligations are either known or considered probable and can be reasonably estimated. Such estimates require judgment with respect to costs, time frame and extent of required remedial and clean-up activities and are subject to periodic adjustments based on currently available information. At December 31, 2015 and 2014, we had no accrued expenses related to environmental costs.

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Provision for Income Taxes

For federal income tax purposes, we report our income, expenses, gains, and losses as a partnership not subject to income taxes. As such, each partner is responsible for his or her share of federal and state income tax. Net earnings for financial statement purposes may differ significantly from taxable income reportable to each partner as a result of differences between the tax basis and financial reporting basis of assets and liabilities.

We are responsible for our portion of the Texas margin tax that is included in our subsidiaries' consolidated Texas franchise tax returns. The margin tax qualifies as an income tax under GAAP, which requires us to recognize the impact of this tax on the temporary differences between the financial statement assets and liabilities and their tax basis attributable to such tax.

Emerge Energy Distributors Inc. (“Distributor”), our subsidiary that supports the Fuel segment, reports its income, expenses, gains, and losses as a corporation and is subject to both federal and state income taxes. Our provision for income taxes relates to: (i) Texas margin taxes for the Partnership and for Distributor, as well as (ii) federal and state income taxes for Distributor.

Fair Value of Financial Instruments

Fair value is an exit price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. Hierarchy Levels 1, 2, or 3 are terms for the priority of inputs to valuation techniques used to measure fair value. Hierarchy Level 1 inputs are quoted prices in active markets for identical assets or liabilities. Hierarchy Level 2 inputs are inputs other than quoted prices included with Level 1 that are directly or indirectly observable for the asset or liability. Hierarchy Level 3 inputs are inputs that are not observable in the market.

Our financial instruments consist primarily of cash and cash equivalents, restricted cash and equivalents, accounts receivable, accounts payable and debt instruments. The carrying amounts of cash and cash equivalents, restricted cash and cash equivalents, accounts receivable and accounts payable are representative of their fair values due to their short maturities. As of December 31, 2015 and 2014, the carrying amount for our $350 million senior secured revolving credit facility approximates fair value because the underlying instrument includes provisions that adjust our interest rates based on current market rates.

Concentration of Credit Risk

Financial instruments that potentially subject us to concentration of credit risk are cash and cash equivalents and trade accounts receivable. Cash deposits with banks are federally insured up to $250,000 per depositor at each financial institution; and certain of our cash balances did exceed federally insured limits as of December 31, 2015. We maintain our cash and cash equivalents in financial institutions we consider to be of high credit quality.

We provide credit, in the normal course of business, to customers located throughout the United States and Canada. We perform ongoing credit evaluations of our customers and generally do not require collateral. In addition, we regularly evaluate our credit accounts for loss potential.

Our two largest customer balances each represented 12% of our net accounts receivable balance as of December 31, 2015, and our third largest customer represented 11% of our net accounts receivable balance as of December 31, 2015, while our two largest customer balances represented 24% and 15% of our net accounts receivable balance as of December 31, 2014. No other customer balances exceeded 10% of the total net accounts receivable balance as of December 31, 2015 and 2014.

No individual customer represented more than 10% of revenues for the years ended December 31, 2015, 2014 and 2013.

Segments

We operate our business in two reportable segments.

- The Sand segment consists of the production and sale of various grades of industrial sand primarily used in the extraction of oil and natural gas, as well as the production of building products and foundry materials.
- The Fuel segment operates two terminals and two transmix processing facilities that are located in the Dallas-Fort Worth, Texas area and Birmingham, Alabama. In addition to refining transmix, the Fuel segment sells a suite of complementary fuel products and services, including third-party terminaling services, the sale of wholesale petroleum products, certain reclamation services (which consist primarily of tank cleaning services) and blending of renewable

fuels.

For operations and other Partnership activities not managed through our two operating segments, these items of income, if any, and costs are presented herein as “corporate.” Our chief operating decision maker (“CODM”) is our chief executive officer. The CODM allocates resources and assesses performance of the business based on segment income or loss as presented in Note 16.

Seasonality

For our Sand segment, winter weather affects the months during which we can wash and wet-process sand in Wisconsin. Seasonality is not a significant factor in determining our ability to supply sand to our customers because we accumulate a stockpile of wet

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sand feedstock during non-winter months. During the winter, we process the stockpiled sand to meet customer requirements. However, we sell sand for use in oil and natural gas production basins where severe weather conditions may curtail drilling activities. This is particularly true in drilling areas located in the northern U.S. and western Canada. If severe winter weather precludes drilling activities, our frac sand sales volume may be adversely affected. Generally, severe weather episodes affect production in the first quarter with possible effect continuing into the second quarter. Generally, our Fuel segment does not experience dramatic seasonal shifts in quantities delivered to its customers.

Other Reclassifications

Certain reclassifications have been made to prior period amounts to conform to the current period presentation. These reclassifications do not impact net income and do not reflect a material change in the information previously presented in our consolidated financial statements.

Recent Accounting Pronouncements

In May 2014, the FASB issued Accounting Standards Update ("ASU") 2014-09, Revenue from Contracts with Customers, as a new Topic, Accounting Standards Codification Topic 606. The new revenue recognition standard provides a five-step analysis of transactions to determine when and how revenue is recognized. The core principle is that a company should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. This guidance is effective for annual periods beginning after December 15, 2017 with early adoption permitted on January 1, 2017 and shall be applied retrospectively to each period presented or as a cumulative-effect adjustment as of the date of adoption. We are evaluating the effect of adopting this new accounting guidance but do not expect adoption will have a material impact on our financial position, results of operations or cash flows.

In August 2014, the FASB issued ASU 2014-15, Presentation of Financial Statements—Going Concern. This ASU requires an entity to evaluate whether conditions or events, in the aggregate, raise substantial doubt about the entity's ability to continue as a going concern for one year from the date the financial statements are issued or are available to be issued. The new guidance is effective for annual periods and interim periods within those annual periods beginning after December 15, 2016. We are evaluating the effect of adopting this new accounting guidance but do not expect adoption will have a material impact on our financial position, results of operations or cash flows.

In April 2015, the FASB issued ASU No. 2015-03, Interest—Imputation of Interest, to modify the presentation of debt issuance costs. Under ASU 2015-03 debt issuance costs are required to be presented as a direct deduction of debt balances on the statement of financial position, similar to the presentation of debt discounts. ASU 2015-03 is effective for public companies for years beginning after December 15, 2015, and interim periods within those fiscal periods. For all other entities, ASU 2015-03 is effective for years beginning after December 15, 2015 and interim periods within annual periods beginning after December 15, 2016. Early adoption is permitted for financial statements that have not already been issued. Additionally, the provisions should be applied on a retrospective basis as a change in accounting principle. We adopted ASU 2015-03 as of March 31, 2015. The adoption of this new accounting guidance resulted in a reclassification of deferred financing costs from "Other assets, net" to "Long-term debt, net of current portion" on our condensed consolidated balance sheets for the current and all prior periods. There was no impact on our results of operations or cash flows.

In July 2015, the FASB issued ASU 2015-11, Simplifying the Measurement of Inventory. Under this ASU, inventory will be measured at the lower of cost and net realizable value and options that currently exist for market value will be eliminated. The ASU defines net realizable value as the estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. No other changes were made to the current guidance on inventory measurement. ASU 2015-11 is effective for interim and annual periods beginning after December 15, 2016. Early application is permitted and should be applied prospectively. We are evaluating the effect of adopting this new accounting guidance but do not expect adoption will have a material impact on our financial position, results of operations or cash flows.

In February 2016, the FASB issued ASU 2016-02, Leases. This ASU requires lessees to recognize lease assets and lease liabilities generated by contracts longer than a year on their balance sheet. The ASU also requires companies to disclose in the footnotes to their financial statements information about the amount, timing, and uncertainty for the payments they make for the lease agreements. ASU 2016-02 is effective for public companies for annual periods and interim periods within those annual periods beginning after December 31, 2018. For all other entities, ASU 2016-02 is effective for years beginning after December 15, 2019 and interim periods thereafter. Early adoption is permitted for all entities. We are evaluating the effect of adopting this new accounting guidance.

3. ACQUISITIONS

Acquisition of Direct Fuels

Concurrent with our IPO on May 14, 2013, we acquired Direct Fuels from Direct Fuels Partners, L.P. for $98.3 million, in order to expand our operations, gain new customers, improve earnings, and increase our markets through a larger geographical presence. Direct Fuels operates a motor fuel terminal and transmix processing facilities in Texas. Direct Fuels' identifiable assets acquired and liabilities assumed by us were recognized based upon the fair values determined on the date of acquisition.

We determined the fair values of Direct Fuels property, plant and equipment as well as its identifiable intangible assets with assistance from an independent third-party appraisal specialist. Our assessment of the fair value of the assets acquired and liabilities assumed as of May 14, 2013 indicates that the consideration given exceeded the fair value of net identifiable assets acquired. Our assessment indicated that goodwill, the excess of consideration over the fair value of net identifiable assets acquired, is $29.3 million. The primary factor that gives rise to goodwill is the premium we were willing to pay to expand our operations into the geographical territories currently served by Direct Fuels. The ability to expand our operations encompasses gaining access to new customers combined with the improved margins attainable through increased market exposure. Additionally, the goodwill is attributable to the value of Direct Fuels' assembled workforce, including a management team, as well as synergies that arose through the streamlining of operations.

The reconciliation of fair values of the assets acquired and liabilities assumed related to the Direct Fuel purchase price follows ($ in thousands):

Total purchase price	$98,277
Fair value of assets and liabilities acquired:	
Cash	6,197
Accounts receivable	9,845
Other current assets	13,146
Property, plant and equipment	14,897
Intangible assets	45,080
Goodwill	29,264
Total assets acquired	118,429
Less accounts payable and accrued liabilities	8,652
Less dividend payable	11,500
Total current liabilities	20,152
Net assets acquired	$98,277

The consideration for the Direct Fuels acquisition included payment of $22.9 million in cash, issuance of 3,180,612 common units with a fair value totaling $53.7 million, and assumption of $21.7 million in long-term debt. The accounts receivable acquired represent the gross contractual amounts and are stated at fair value. Subsequent to May 14, 2013, we have collected the accounts receivable in the table above. Prior to the acquisition, Direct Fuels declared a cash dividend totaling $11.5 million which was paid after the acquisition.

We attributed $45.1 million to intangible assets associated with Direct Fuels' customer relationships, long-term supply and transportation contracts, and a non-compete agreement. We amortize the customer relationships using an accelerated method (based on expected future cash flows) and the other intangibles using straight-line method over their estimated useful lives. The useful lives range as follows: (i) customer relationships, 15 years; (ii) long-term supply and transportation assets, 3 to 54 months; and (iii) non-compete agreement, 4 years.

In 2013, we expensed $1.5 million of transaction costs associated with the acquisition of Direct Fuels. We reported these costs as IPO transaction-related costs within operating expenses. For the period May 14, 2013 (date of acquisition) through December 31, 2013, Direct Fuels' revenues totaled $218.2 million and it reported a net loss of $1.5 million.

The financial position and results of operations of Direct Fuels are included in our consolidated financial statements from and as of the date of acquisition. The following unaudited pro forma financial information presents the combined results of operations of the Partnership and Direct Fuels as if the transaction had occurred on January 1, 2013. The pro forma information is not necessarily indicative of what the results of operations actually would have been had the acquisition been completed on January 1, 2012. In addition, the unaudited pro forma financial information is not indicative of, nor does it purport to project, our future operating results. The unaudited financial information excludes acquisition and integration costs and does not give effect to any estimated and potential cost savings or other operating efficiencies, if any, that might result from the acquisition.

	Year Ended December 31, 2013 ($ in thousands)
Revenues	$996,587
Net income	$38,258

Acquisition from Midwest

On July 25, 2014, we acquired certain assets and obligations of Midwest Frac and Sands LLC (“Midwest”) in order to expand access to high quality sand reserves near our Wisconsin processing plants, improve earnings, and exert greater control over our sand feedstock supply. Midwest operated a sand mine and wet wash facility in Barron County, Wisconsin. The assets include, but are not limited to, mineral reserves, real estate, buildings, land improvements, wet wash processing and conveying equipment, fixtures and office equipment, permits, and a non-compete agreement with the seller. The liabilities assumed include accounts payable and a local government highway repair and maintenance agreement. We have accounted for the acquisition as a business combination under ASC 805, Business Combinations.

The purchase agreement specifies a total cash purchase price of $24.0 million plus contingent consideration, if any. The agreement required an advance payment of $11.0 million in June 2014. The additional $13.0 million is being paid over time as sand is removed from the reserves, with a minimum of $2.0 million paid each year. After repayment of $13.0 million, we will continue to pay contingent consideration for any additional sand we remove, for as long as the sand reserves remain economically viable. We used a discounted cash flow analysis to estimate the present value of the contingent consideration and other liabilities assumed as of the purchase date, using management’s estimates of the volumes and timing of sand extraction. We estimate that the entire obligation will be repaid within 7 - 8 years after acquisition, assuming production of approximately 850,000 tons of wet washed sand per year. The seller can repurchase the land when we determine the property is no longer viable for our sand mining and processing activities.

As part of the agreement, we cancelled an existing tolling agreement whereby we agreed to convert Midwest’s wet washed sand to dry sand as well as an existing supply contract whereby Midwest agreed to supply and deliver wet washed sand. We recorded a $0.7 million loss on settlement of pre-existing agreements as a component of “Other” expense on our Consolidated Statements of Operations. We estimated the fair values of the terminated agreements using a discounted cash flow analysis.

We retained a third-party expert to assist in determining the volumes and quality of the in-place mineral reserves. With assistance from a third-party valuations expert, we then used this data in our determination of the fair values of identifiable net assets, using the income approach. Our assessment of the fair values of the assets acquired and liabilities assumed as of July 25, 2014 indicates that there was no goodwill associated with the acquisition. We recognized the assets acquired and liabilities assumed based upon the fair values determined on the date of acquisition, using significant inputs that are not observable in the market (i.e., Level 3 inputs).

Following is a reconciliation of the total consideration to the assets acquired and liabilities assumed as of the acquisition date ($ in thousands):

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Consideration:	
Cash deposit	$11,000
Present value of purchase obligation	11,226
Present value of contingent consideration	853
Loss on settlement of pre-existing agreements	(689)
Total consideration	$22,390
Assets acquired:	
Mineral reserves	$19,381
Other property, plant and equipment	4,403
Non-compete agreement	100
Total assets acquired	23,884
Less liabilities assumed:	
Governmental highway improvement obligation	1,128
Asset retirement obligation	227
Accounts payable	139
Net assets acquired	$22,390

In our Consolidated Balance Sheets, we have classified the non-current portion of the purchase obligation in "Business acquisition obligation, net of current portion." The governmental highway improvement obligation and the current portion of the purchase obligation are classified as "Accrued liabilities."

We incurred approximately $0.1 million in transaction costs, which were recorded as "Selling, general and administrative expenses" as incurred.

The historical financial information for the assets acquired was impractical to obtain, and inclusion of pro forma information would require us to make estimates and assumptions regarding these assets' historical financial results that may not be reasonable or accurate. As a result, supplemental pro forma results are not presented. This acquisition is not expected to impact our consolidated revenues. It is impractical to determine net income included in our consolidated statements of operations relating to Midwest since the date of acquisition because Midwest has been fully integrated into our sand segment operations and the operating results. For this reason, the operating results of Midwest cannot be separately identified.

4. INVENTORIES

Inventories consisted of the following:

	As of December 31,	
	2015	2014
	($ in thousands)	
Sand work in process	$17,795	14,413
Sand finished goods	12,224	7,582
Refined fuels	10,289	8,031
Fuel raw materials and supplies	2,168	2,157
Sand raw materials and supplies	142	95
Total inventory	$42,618	$32,278

5. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment consisted of the following:

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	As of December 31, 2015	2014
	($ in thousands)	
Machinery and equipment (1)	$160,203	$146,951
Buildings and improvements (1)	58,036	51,027
Land and improvements (1)	47,901	37,461
Mineral reserves	30,181	30,181
Construction in progress	9,555	24,172
Capitalized reclamation costs	2,445	2,332
Total cost	308,321	292,124
Accumulated depreciation and depletion	74,691	53,467
Net property, plant and equipment	$233,630	$238,657

(1) Includes assets under capital lease

6. INTANGIBLE ASSETS OTHER THAN GOODWILL

Our intangible assets other than goodwill consisted of the following at December 31, 2015 and 2014:

	Cost	Accumulated Amortization	Net
	($ in thousands)		
December 31, 2015:			
Trade names	$46	$23	$23
Patents	7,000	234	$6,766
Customer relationships	43,922	21,267	22,655
Supply and transportation agreements	3,801	2,367	1,434
Non-compete agreement	1,550	981	569
Total	$56,319	$24,872	$31,447
December 31, 2014:			
Trade names	$46	$20	$26
Customer relationships	43,922	15,293	28,629
Supply and transportation agreements	3,330	1,769	1,561
Non-compete agreement	1,550	608	942
Total	$48,848	$17,690	$31,158

The following table presents the estimated future amortization expense related to intangible assets through 2020:

Year Ending December 31,	($ in thousands)
2016	$8,688
2017	7,267
2018	4,416
2019	2,610
2020	2,081

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7. ACCRUED LIABILITIES

Accrued liabilities consisted of the following:

	As of December 31,	
	2015	2014
	($ in thousands)	
Sales, excise, property and income taxes	$3,276	$5,002
Current portion of business acquisition obligation	2,843	2,702
Purchase of intangible assets	2,500	—
Logistics	2,486	3,185
Deferred compensation	1,540	1,341
Salaries and other employee-related	1,096	4,048
Accrued interest	947	407
Derivative contract liability	624	422
Sand purchases and royalties	520	659
Current portion of contract termination	135	—
Mining	—	951
Deferred revenue	—	127
Construction	—	3,379
Other	2,434	2,188
Total	$18,401	$24,411

8. LONG-TERM DEBT

Following is a summary of our long-term debt:

	As of December 31,	
	2015	2014
	($ in thousands)	
Revolving credit facility		
Principal	$302,063	$221,864
Deferred financing costs, net	(6,125)	(4,841)
Other notes	—	53
Total debt	295,938	217,076
Less current portion	—	53
Long-term portion	$295,938	$217,023

Revolving Credit Facility

On May 14, 2013, we entered into a $150 million revolving credit and security agreement (as amended and restated, the “Credit Agreement”) among Emerge Energy Services LP, as parent guarantor, each of its subsidiaries, as borrowers (the “Borrowers”), and PNC Bank, National Association, as administrative agent and collateral agent. Substantially all of the assets of the Borrowers are pledged as collateral under the Credit Agreement.

On December 10, 2013, we amended the Credit Agreement to revise certain definitions and to increase the commitment amount for our revolving loan credit facility to $200 million.

On June 27, 2014, we amended and restated the Credit Agreement to, among other things:

- increase our revolving credit facility (the “Credit Facility”) to $350 million, which we may increase from time to time upon our satisfaction of certain conditions by up to an aggregate of $150 million;
- increase the sublimit for the issuance of letters of credit to $30 million;

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- revise financial covenants as discussed below; and
- extend the maturity date to June 27, 2019.

We also incur a commitment fee of 0.375% on committed amounts that are neither used for borrowings nor under letters of credit.

In May 2013, we initially borrowed $112.7 million to (i) make distributions of $17.0 million to Superior Silica Holdings LLC ("SSH") and to fund the cash payment in the Direct Fuels acquisition amounting to $22.2 million; and, (ii) repay $73.5 million of existing SSH debt. As part of the original Credit Agreement, we incurred $3.6 million of direct financing costs for professional and legal fees, which we recorded as deferred financing cost. We subsequently incurred $0.1 million and $2.5 million in deferred financing costs related to amendments in 2013 and 2014, respectively.

The Credit Agreement contains various covenants and restrictive provisions and requires maintenance of financial covenants as follows:

- an interest coverage ratio (as defined in the Credit Agreement) of not less than 3.00 to 1.00; and
- a total leverage ratio (as defined in the Credit Agreement) of not greater than 3.00 to 1.00. On April 6, 2015, we entered into an amendment to the Credit Agreement that increased this leverage ratio to 3.50 to 1.00.

On September 30, 2015, our total leverage ratio exceeded the threshold of 3.50 to 1.00. We were in compliance with all other covenants at that time. We advised the lenders under the Credit Agreement when we became aware of the potential covenant breach, and on October 19, 2015, we entered into a limited waiver to the Credit Agreement whereby the lenders waived any default or right to exercise any remedy as a result of our failure to be in compliance with the leverage covenant for the fiscal quarter ended September 30, 2015. As consideration for the waiver, we agreed to not make any repurchases of or quarterly cash distributions on our common units prior to November 13, 2015 and to limit the aggregate amount of advances made under the Credit Agreement between October 19, 2015 and November 13, 2015 to no more than $25 million. On November 12, 2015, we entered into a second limited waiver to the Credit Agreement which extended the period of the waiver granted until November 20, 2015.

On November 18, 2015, we, PNC Bank, National Association, as agent, and the lenders entered into the Second Amendment to the Credit Agreement (the "Second Amendment"). The Second Amendment, among other things, forgoes the application of the total leverage ratio and interest coverage ratio covenants until the earlier of June 30, 2018 or such time as our total leverage ratio is less than 3.50 to 1.00 as of the end of any two consecutive fiscal quarters (the "ratio compliance date"). Prior to the ratio compliance date, we will be subject to the following covenants and restrictions:

- the $350 million total aggregate commitment under the Credit Agreement will be reduced in an amount equal to the net proceeds of any notes offerings we may make in the future;
- we will be required to maintain at least $25 million of excess availability (as defined in the Credit Agreement) under the Credit Agreement; and
- we will be required to generate consolidated EBITDA in certain minimum amounts beginning with the quarter ending December 31, 2015 and rolling forward thereafter.

In addition, the Second Amendment increases the interest rates applicable to borrowings under the Credit Agreement to either, (at our option) (i) LIBOR plus 4.25% or (ii) the base rate plus 3.25%. The Second Amendment also provides for the following covenants and restrictions:

- our subsidiaries will be restricted from making distributions to us (to permit us to make distributions to unitholders) if, after giving pro forma effect to such distribution, our total leverage ratio would be greater than or equal to 4.00 to 1.00 or the excess availability under the Credit Agreement would be less than the greater of $43.75 million or 12.5% of the total aggregate commitments;
- we will be restricted from entering into certain substantial acquisition or merger agreements with third-party businesses or making certain other investments;
- through March 31, 2019, our capital expenditures for growth and maintenance will be restricted and may not exceed certain amounts per quarter;

At December 31, 2015, we were in compliance with our loan covenants and had undrawn availability under the Credit Facility totaling $39.1 million. At December 31, 2015, our outstanding borrowings under the Credit Agreement bore interest at a weighted-average rate of 5.08%.

9. COMMITMENTS AND CONTINGENCIES

Contractual Obligations

The following table presents the minimum contractual obligations for contractual commitments as of December 31, 2015.

	Railcar Leases (1)	Other Operating Leases	Royalty Commitments	Purchase Commitments (2)
	($ in thousands)			
Year ending December 31,				
2016	$59,161	$1,607	$230	$27,556
2017	55,500	914	230	23,376
2018	62,448	574	230	24,517
2019	66,618	320	230	22,527
2020	57,908	269	230	21,322
Thereafter	245,376	2,774	1,710	48,805
Total	$547,011	$6,458	$2,860	168,103
Less amount representing interest				(1,304)
Total less interest				$166,799

(1) Includes minimum amounts payable under various operating leases as well estimated costs necessary to transport leased railcars from the manufacturer to our site for initial placement in service for those railcars to be delivered in the future.

(2) Includes various obligations for services as well as estimated payments for business acquisition obligation, inclusive of expected contingent consideration, based on forecasted volumes.

Operating Leases

We lease railcars, rail track, locomotives, office and terminal facilities, land, and equipment with various terms in connection with our daily operations. Operating lease expense for the years ended December 31, 2015, 2014 and 2013 totaled $35.6 million, $21.5 million and $6.0 million, respectively.

Royalty Commitments

We maintain various royalty agreements related to the extraction of sand in Wisconsin, of which certain agreements require minimum payments if minimum volumes are not extracted on an annual basis. For the years ended December 31, 2015, 2014, and 2013, we met or exceeded our minimum commitment requirements under all of our royalty agreements.

Purchase Commitments

We entered into several transload services agreements in 2014 with terms from five to ten years with minimum annual commitments. In May 2012, we entered into a railway shipping agreement requiring us to pay a shortfall penalty if minimum annual tonnage levels are not shipped for a term of 10 years commencing on December 1, 2012. We maintain minimum annual purchase commitments with a third-party wet sand supplier with an original term of five years. In addition, we acquired certain sand mining and processing assets in a business acquisition for which we will pay the consideration, including estimated contingent consideration, over five to seven years based on volumes of sand extracted (see Note 2 above for further discussion). For the years ended December 31, 2015, 2014 and 2013, we met or exceeded our minimum commitment requirements under all of our purchase agreements.

Capital Lease Obligations

In April 2014, a five-year contract with a sand processor (“Processor”) became effective to support our sand business in Wisconsin. Under this contract, the Processor financed and built a wet wash processing plant near our Wisconsin operations. As part of the agreement, the Processor wet washes our sand, creates stockpiles of washed sand and maintains the plant and equipment. During the term of the agreement the Processor will own the wet plant along with the equipment and other temporary structures used to support this activity. At the end of the five-year term of the agreement or following a default under the contract by the Processor, we have the right to take ownership of the wet plant and other equipment without charge. Subject to certain conditions, ownership of the plant and equipment will transfer to us at the expiration of the term. We accounted for the wet plant as a capital lease obligation. The original capitalized lease asset and corresponding capital lease obligation totaled $3.3 million. Due to higher than anticipated purchase volumes during 2014, we anticipate we will extinguish the capital lease earlier than originally planned. However, we will still be subject to minimum sand purchase obligations after the capital lease is repaid.

Other Commitments and Contingencies

Excise Tax Penalty

In 2012, we received an IRS notice of a penalty totaling $340,000 due to failure to file terminal operator reports in electronic format. We filed these returns in paper format. Management protested the audit findings through IRS appeal channels. On May 29, 2015, IRS offered to reduce the penalty to $50,000 which we accepted and paid on June 9, 2015.

Property Value Assurance

On May 13, 2013, we entered into a mining agreement with the Town of Sioux Creek, Wisconsin (“Sioux Creek”) that addresses local regulations related to the operation of our future facility in Sioux Creek. The agreement expires at the end of twenty years. The agreement covers hours and days of operation, royalty payments, control of light and noise, and a property value guaranty or assurance (“PVA”). The PVA provision requires our guaranty of certain owners' property values, as defined in Sioux Creek's ordinance which could require us to make future payments to the specified property owners, if any. The ordinance states that any adjoining property owner, that was an owner prior to commencement of operations, that markets their property for third-party sale subsequent to commencement of operations may have their property appraised by a real estate appraiser in the State of Wisconsin to determine fair market value as if the mining operation did not exist (if the mine operator and land owner do not agree on the appraiser both may chose an appraiser and the average of the two appraisals shall determine fair market value). Certain provisions allow the mine operator to purchase the property or to reimburse the landowner for any shortfall between the selling price and the fair market value established by appraisal within a six months timeframe.

On November 9, 2013, we entered into a mining agreement with the Town of Auburn, Wisconsin (“Auburn”) that addresses local regulations related to sand mining and sand processing activities at our New Auburn, Wisconsin facility. The agreement expires on December 31, 2043. The agreement covers hours of operation, use of roads, control of light and noise, air quality and fugitive dust, control of waste materials, groundwater standards, and a PVA. The PVA provisions include our guaranty of certain owners' property values, as defined in the agreement, and set forth the terms by which we could be required to make future payments to the specified property owners, if any. We are required to pay the property owner the excess of fair market value over selling price, if any. In addition, if the owner's property fails to sell after 270 days from the date listed for sale, we are obligated to purchase the property for fair market value. The agreement defines fair market value using one of two methods: (i) the value identified in the Town's 2011 tax rolls plus 10%; or, in the event the property owner believes the other method does not accurately reflect fair market value, (ii) a then current appraisal prepared by a third party expert using comparable values for similar properties not located within one-quarter mile of a mine site. In the event the property owner sells the property for an amount exceeding fair market value, we are under no obligation to make payment. The PVA provision runs with the land and is binding on the property owners, us, and their heirs, grantees, representatives, successors, and assigns.

In December 2015, we entered into an agreement to purchase certain properties and assume leases and other related agreements for future development of sand mining and processing facilities in Wisconsin. Given the current challenging market conditions for proppant demand, we do not plan to begin development until the North American oil and gas markets improve. Under a mining agreement with a local town, we have assumed contingent obligations to indemnify owners of approximately 141 properties for diminution of value associated with mine operations and limited moving expenses when each landowner decides to sell a property, even if no mine is yet in operation. As these contingent liabilities cannot be reasonably estimated, no liability has been recorded.

We have not accrued a liability related to the PVAs noted above as management does not believe a future payment is probable or reasonably estimable as of December 31, 2015. We have paid less than $0.1 million for these guarantees to date.

Letters of Credit

As of December 31, 2015, we had various letters of credit outstanding totaling $8.0 million. These letters of credit support various railcar lease obligations as well as reclamation obligations for sand mining properties.

Litigation and Potentially Uninsured Liabilities

We are subject to various claims and litigation arising in the ordinary course of business. We maintain general liability insurance with limits and deductibles that management believes prudent in light of our exposure to loss and the cost of insurance. We had recognized no liabilities as of December 31, 2015 and 2014 related to uninsured claims and litigation, and current uninsured litigation matters are not expected to have a material adverse effect on our financial position, liquidity or results of operations. We expense legal costs related to claims and litigation in the period incurred.

Environmental Matter

On November 21, 2013, the EPA issued a General Notice Letter and Information Request ("Notice") under Section 104(e) of the Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended ("CERCLA"), to one of our subsidiaries operating within the Fuel segment. The Notice provides that the subsidiary may have incurred liability with respect to the Reef Environmental site in Alabama, and requested certain information in accordance with Section 107(a) of CERCLA. We timely responded to the Notice. At this time, no specific claim for cost recovery has been made by the EPA (or any other potentially responsible party) against us. There is uncertainty relating to our share of environmental remediation liability, if any, because our allocable share of wastewater is unknown and the total remediation cost is also unknown. Consequently, management is unable to estimate the possible loss or range of loss, if any. We have not recorded a loss contingency accrual as of December 31, 2015 and 2014. In the opinion of management, the outcome of such matters is not expected to have a material adverse effect on our financial position, liquidity or results of operations.

10. PROJECT TERMINATIONS

In 2014 and 2015, we began development of sand processing facilities in Independence, Wisconsin and other small projects in Ohio and Missouri. Due to a number of complications, such as an increase in projected operating costs and a decline in the market price and demand for frac sand in early 2015, we determined that these projects were no longer economically viable. In 2015, we recorded a $9.3 million charge to earnings, of which $9.2 million related to the Independence, Wisconsin facilities. This charge to earnings included items such as engineering, legal and other professional service fees, site preparation costs, and writedowns of assets to estimated net realizable value.

In 2015, we revalued assets purchased for the facility in Independence, Wisconsin to their fair values of $6.2 million using Level 3 inputs and wrote off $1.7 million in December 2015.

Management committed to a plan to discontinue these project in April 2015. In accordance with FASB ASC 420, Exit or Disposal Cost Obligations, any contract termination charges and estimated values of continuing contractual obligations for which we will receive no future value will be recognized as a charge to earnings as of the contract termination date or cease-use date. We estimated these contract termination charges to be approximately $1.4 million. These liabilities will be reviewed periodically and may be adjusted when necessary, but we do not expect any such adjustments to be significant.

The following table illustrates the exit and disposal reserves related to the termination of the Independence, Wisconsin project included in Accrued liabilities and Other long-term liabilities in our Condensed Consolidated Balance Sheets:

	($ in thousands)
Balance at December 31, 2014	$—
Contract termination charges	1,352
Accretion	31
Payments	(86)
Balance at December 31, 2015	$1,297

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11. RELATED PARTY TRANSACTIONS

Related party transactions included in our Consolidated Balance Sheets and Consolidated Statements of Operations are summarized in the following table:

	2015	2014	2013
	($ in thousands)		
Balances for the year ended December 31:			
Wages and employee-related costs (1)	$27,454	$26,875	$17,366
Interest expense (2)	—	—	1,915
IPO transaction-related cost reimbursements (3)	—	—	1,643
General and administrative expense reimbursements (3)	280	75	180
Consulting services (4)	—	—	112
Lease expense	25	25	24
Balances as of December 31:			
Accounts receivable	$295	$181	$124
Accounts payable and accrued liabilities	553	704	515

(1) We do not have any employees. Prior to May 14, 2013, our Predecessor and Direct Fuels had employees assigned directly to their respective operations. On May 14, 2013, our general partner hired all employees of the Predecessor and Direct Fuels. After this date, our general partner manages our human resource assets, including fringe benefits and other employee-related charges. We routinely and regularly reimburse our general partner for any employee-related costs paid on our behalf, and report such costs as operating expenses.

(2) Debt payable to related parties was repaid using proceeds of our IPO in May 2013.

(3) We paid Insight Equity certain IPO transaction-related costs and other general and administrative costs. We also paid $40,000 to one of our independent directors for production of a video clip for investors and press.

(4) Prior to May 14, 2013, our Fuel segment paid an affiliated company for leadership services at an annual amount of $250,000 plus bonus for financial performance, if any. Beginning May 14, 2013, these services are being performed by Insight Equity employees and are charged to us through the reimbursement process described in (1) above.

Agreements with Affiliates

Registration Rights Agreement. In connection with closing of the IPO, we entered into a Registration Rights Agreement, dated as of May 14, 2013 (the “Registration Rights Agreement”), by and between AEC Resources LLC, Ted W. Beneski, Superior Silica Resources LLC, Kayne Anderson Development Company and LBC Sub V, LLC. Pursuant to the Registration Rights Agreement, we agreed to register for resale the restricted common units of the Partnership (the “Restricted Units”) issued to the other parties to the Registration Rights Agreement. We also agreed, subject to certain limitations, to allow the holders to sell Restricted Units in connection with certain registered offerings that we may conduct in the future and to provide holders of a specified number of Restricted Units the right to demand that we conduct an underwritten public offering of Restricted Units under certain circumstances. The Registration Rights Agreement contains representations, warranties, covenants and indemnities that are customary for private placements by public companies.

Services Agreement. On May 14, 2013, in connection with the closing of the IPO, we entered into an administrative services agreement with Insight Equity, pursuant to which Insight Equity provides specific general and administrative services to us. Under this agreement, we reimburse Insight Equity based on agreed upon formulas for actual travel and other expenses on our behalf. In addition, an executive employee of Insight Equity is the head of the Fuel segment. We pay this executive for services rendered to the Fuel segment and record these costs as a charge to earnings. The administrative services agreement will remain in force until (i) the date we and Insight Equity mutually agree to terminate it; (ii) the final distribution in liquidation of the Partnership or our subsidiaries; or (iii) the date on which either Insight Equity or its affiliates collectively controls less than 51% of equity of our general partner.

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12. EQUITY-BASED COMPENSATION

Effective May 14, 2013, we adopted our 2013 Long-Term Incentive Plan (the "LTIP") for providing long-term incentives for employees, directors, and consultants who provide services to us, and provides for the issuance of an aggregate of up to 2,321,968 common units to be granted either as options, restricted units, phantom units, distribution equivalent rights, unit appreciation rights, unit award, profits interest units, or other unit-based award granted under the plan. All of our outstanding grants will be settled through issuance of limited partner common units.

On May 14, 2013, we granted 530,588 and 265,294 phantom units to our CEO and Sand Officer, respectively. Half of these phantom units vested after one year, and the remaining half vested on May 14, 2015. For phantom units granted to employees in 2013, we currently assume a 43-month vesting period, which represents management's estimate of the amount of time until all vesting conditions have been met. Concurrent with the closing of a secondary offering in June 2014 and the exercise of the underwriters' over-allotment in July 2014, 90,686 of these phantom units vested and common units were issued. For other phantom units granted to employees, we assume a 36 to 48-month vesting period. Restricted units are awarded to our independent directors on each anniversary of our IPO, each with a vesting period of one year. Regarding distributions for independent directors and other employees, distributions are credited to a distribution equivalent rights account for the benefit of each participant and become payable generally within 45 days following the date of vesting. As of December 31, 2015, the unpaid liability for distribution equivalent rights totaled $1.5 million.

In 2015, we granted 33,042 time based phantom units to certain officers and other employees to vest in equal installments on each anniversary date of the grant over a period of three or four years. We also granted 16,242 market based phantom units to certain officers in 2015. Half of these units will vest when the per-unit closing price increases by 25% or 50% (depending on the grants) and the other half will vest when the per-unit closing price doubles from the per-unit closing price on the initial grant dates.

The following table summarizes awards granted during the year ended December 31, 2015.

	Total Units	Phantom Units	Restricted Units	Fair Value per Unit at Award Date
Outstanding at December 31, 2014	605,664	602,836	2,828	$ 18.12
Granted	59,771	49,284	10,487	35.69
Vested	(401,011)	(397,941)	(3,070)	17.5
Forfeitures	(39,424)	(37,375)	(2,049)	33.33
Outstanding at December 31, 2015	225,000	216,804	8,196	$ 21.22

For the years ended December 31, 2015 and 2014, we recorded non-cash compensation expense relating to equity-based compensation of $3.5 million and $9.0 million, respectively, in selling, general and administrative expenses. As of December 31, 2015, the unrecognized compensation expense related to the grants discussed above amounted to $2.0 million to be recognized over a weighted average of 1.29 years.

13. IPO TRANSACTION-RELATED COSTS

We incurred generally non-recurring expenses related directly to the IPO. These costs consist primarily of incentive compensation and payroll-related costs paid to management. In addition, we incurred indirect legal, accounting, and other professional fees associated with the IPO transaction not related to the issuance of equity and debt. We reported these amounts as an operating expense for the year ended December 31, 2013. The following table summarizes these costs (in thousands):

	Year Ended December 31, 2013
Incentive compensation:	
Compensation and payroll-related costs for termination of LTIC plan	$6,512
Incentive compensation and payroll-related costs to other management employees	2,853
Other IPO-related costs	1,601
Total IPO transaction-related expenses	$10,966

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14. INCOME TAXES

Provision for Income Taxes

Our provision for income taxes relates to: (i) Texas margin taxes for the Partnership and for Emerge Energy Distributors Inc. ("Distributor"), as well as (ii) federal and state income taxes for Distributor. For federal income tax purposes, we report our income, expenses, gains, and losses as a partnership not subject to income taxes. As such, each partner is responsible for his or her share of federal and state income tax. Net earnings for financial statement purposes may differ significantly from taxable income reportable to each partner because of differences between the tax basis and financial reporting basis of assets and liabilities. Distributor reports its income, expenses, gains, and losses as a corporation and is subject to both federal and state income taxes.

The composition of our provision for income taxes follows:

	Year Ended December 31,		
	2015	2014	2013
	($ in thousands)		
Federal and state income tax expense for Distributor	$231	$378	$188
Texas margin tax	288	197	198
Canadian income tax	(15)	63	—
Total provision for income taxes	$504	$638	386

Effective Income Tax Rate

Distributor began operations in May 2013. For the year ended December 31, 2015, Distributor's effective income tax rate was 36%. For Distributor, there were no significant differences between book and taxable income. We are responsible for our portion of the Texas margin tax that is included in our subsidiaries' consolidated Texas franchise tax returns. For our operations in Texas, the effective margin tax rate is approximately 0.95% as defined by applicable state law. The margin tax qualifies as an income tax under GAAP, which requires us to recognize the impact of this tax on the temporary differences between the financial statement assets and liabilities and their tax basis attributable to such tax.

15. EARNINGS PER COMMON UNIT

We compute basic earnings per unit by dividing net income by the weighted-average number of common units outstanding including participating securities. Participating securities include unvested equity-based payment awards that contain non-forfeitable rights to distributions. For these purposes, unvested grants to our CEO and the Sand Officer are deemed participating securities. Since these participating units don't have the obligation to share in net losses, they are excluded in the earnings per unit computation in net loss situations.

Diluted earnings per unit is computed by dividing net income by the weighted-average number of common units outstanding, including participating securities, and increased further to include the number of common units that would have been outstanding had potential dilutive units been exercised. The dilutive effect of restricted units is reflected in diluted net income per unit by applying the treasury stock method. Under FASB ASC 260-10-45, Contingently Issuable Shares, 170,720 of our outstanding phantom units are not included in basic or diluted earnings per common unit calculations as of December 31, 2015. We incurred a net loss for the year ended December 31, 2015, and therefore excluded all potentially dilutive restricted units from the diluted earnings per unit calculation for that period as their effect would have been anti-dilutive.

Basic and diluted earnings per unit are computed as follows:

	Year ended December 31,		
	2015	2014	2013
	($ in thousands except per unit data)		
Net income (loss)	$(9,411)	$89,079	$22,046
Basic earnings per unit:			
Weighted average common units outstanding	23,973,850	23,527,469	23,219,680
Weighted average phantom units deemed participating securities	—	542,949	795,882
Total	23,973,850	24,070,418	24,015,562
Earnings (loss) per common unit (basic)	$(0.39)	$3.70	$0.92
Diluted earnings per unit:			
Weighted average common units outstanding	23,973,850	23,527,469	23,219,680
Weighted average phantom units deemed participating securities	—	542,949	795,882
Weighted average potentially dilutive units outstanding	—	6,019	6,395
Total	23,973,850	24,076,437	24,021,957
Earnings (loss) per common unit (diluted)	$(0.39)	$3.70	$0.92

16. SEGMENT INFORMATION AND GEOGRAPHICAL DATA

Segment Information

We operate our business through two reportable business segments:

- Sand - the production and sale of various grades of sand primarily used in the extraction of oil and natural gas and the production of numerous building products and foundry materials.
- Fuel - the refining of transmix, distribution of finished fuel products, terminal and reclamation activities, and refining of biodiesel.

Segments have been identified based on how management makes operating decisions, assesses performance and allocates resources. Certain items are reviewed by our management on a consolidated basis, and are therefore presented as corporate income rather than segment income:

- general and administrative costs related to corporate overhead, such as headquarters facilities and personnel, as well as equity-based compensation;
- certain other operating costs such as IPO transaction-related; and

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• non-operating items such as interest, other income and income taxes.

Although not used by management in its performance monitoring activities, asset information is included in the following tables together with financial information concerning our reportable segments for the years ended December 31, 2015, 2014 and 2013.

	Year Ended December 31, 2015			
	Sand Segment	Fuel Segment	Corporate	Total
	($ in thousands)			
Revenues	$269,518	$442,121	$—	$711,639
Cost of goods sold (excluding depreciation, depletion and amortization)	209,161	426,664	—	635,825
Depreciation, depletion and amortization	17,863	10,544	34	28,441
Selling, general and administrative expenses	15,142	4,972	13,005	33,119
Project terminations	10,652	—	—	10,652
Operating income (loss)	$16,700	$(59)	$(13,039)	$3,602
Capital expenditures	$27,995	$7,251	$228	$35,474
Total assets (at year end)	$261,761	$139,070	$19,217	$420,048

	Year Ended December 31, 2014			
	Sand Segment	Fuel Segment	Corporate	Total
	($ in thousands)			
Revenues	$341,836	$769,418	$—	$1,111,254
Cost of goods sold (excluding depreciation, depletion and amortization)	204,282	745,724	—	950,006
Depreciation, depletion and amortization	12,777	11,998	28	24,803
Selling, general and administrative expenses	15,821	5,319	17,583	38,723
Operating income (loss)	$108,956	$6,377	$(17,611)	$97,722
Capital expenditures	$76,473	$1,086	$325	$77,884
Total assets (at year end)	$284,330	$142,354	$5,443	$432,127

	Year Ended December 31, 2013			
	Sand Segment	Fuel Segment	Corporate	Total
	($ in thousands)			
Revenues	$167,768	$705,487	$—	$873,255
Cost of goods sold (excluding depreciation, depletion and amortization)	91,416	676,495	—	767,911
Depreciation, depletion and amortization	10,458	10,369	1	20,828
Selling, general and administrative expenses	10,556	6,057	10,222	26,835
IPO transaction-related costs	—	—	10,966	10,966
Operating income (loss)	$55,338	$12,566	$(21,189)	$46,715
Capital expenditures	$20,406	$931	$32	$21,369
Total assets (at year end)	$138,755	$172,833	$7,959	$319,547

Geographical Data

Although we own no long-term assets outside the United States, our Sand segment began selling product in Canada during 2013. We recognized $39.1 million , $30.8 million and $13.6 million of revenues in Canada for the years ended December 31, 2015, 2014, and 2013, respectively. All other sales have occurred in the United States.

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17. DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

We follow FASB ASC 820, Fair Value Measurement, which defines fair value, establishes a framework for measuring fair value, and specifies disclosures about fair value measurements. This guidance establishes a hierarchy for disclosure of the inputs to valuations used to measure fair value. The hierarchy prioritizes the inputs into three broad levels as follows.

- Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities.
- Level 2 inputs are quoted prices for similar assets and liabilities in active markets or inputs that are observable for the asset or liability, either directly or indirectly through market corroboration, for substantially the full term of the financial instrument.
- Level 3 inputs are measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources.

Our valuation models consider various inputs including (a) mark to market valuations, (b) time value and, (c) credit worthiness of valuation of the underlying measurement.

A financial asset or liability's classification within the hierarchy is determined based on the lowest level of input that is significant to the fair value measurement.

The following table shows the three interest rate swap agreements we entered into during 2013 to manage interest rate risk associated with our variable rate borrowings.

Agreement Date	Effective Date	Maturity Date	Notional Amount	Fixed Rate	Variable Rate
Nov. 1, 2013	Oct. 14, 2014	Oct. 16, 2017	$25,000,000	1.33200%	1 Month LIBOR
Nov. 7, 2013	Oct. 14, 2014	Oct. 16, 2017	$25,000,000	1.25500%	1 Month LIBOR
Nov. 21, 2013	Oct. 14, 2014	Oct. 16, 2017	$20,000,000	1.21875%	1 Month LIBOR

Our Fuel segment utilizes financial hedging arrangements whereby we hedge a portion of our gasoline and diesel inventory, which reduces our commodity price exposure on some of our activities. The derivative commodity instruments we utilize consist mainly of futures traded on the New York Mercantile Exchange. As of December 31, 2015 and 2014, we had 2 and 0 open commodity derivative contracts, respectively, to manage fuel price risk.

We do not designate our derivative instruments as hedges under GAAP. As a result, we recognize derivatives at fair value on the consolidated balance sheet with resulting gains and losses reflected in interest expense (for interest rate swap agreements) and cost of goods sold (for derivative commodity instruments), as reported in the consolidated statements of operations. Our derivative instruments serve the same risk management purpose whether designated as a hedge or not. We derive fair values from published market interest rates and fuel price quotes (Level 2 inputs). The precise level of open position commodity derivatives is dependent on inventory levels, expected inventory purchase patterns, and market price trends. We do not use derivative financial instruments for trading or speculative purposes.

The fair values of outstanding derivative instruments and their classifications within our Consolidated Balance Sheets are summarized as follows:

	December 31, 2015	December 31, 2014	Classification
	($ in thousands)		
Derivative assets:			
Commodity derivative contracts	$621	$—	Prepaid expenses and other current assets
Derivative liabilities:			
Interest rate swaps	$472	$422	Accrued liabilities
Commodity derivative contracts	$152	$—	Accrued liabilities

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The effect of derivative instruments, none of which has been designated for hedge accounting, on our Consolidated Statements of Operations was as follows:

	Year Ended December 31,			
	2015	2014	2013	Classification
	(income (expense), $ in thousands)			
Interest rate swaps	$(820)	$(804)	$247	Interest expense, net
Commodity derivative contracts	715	1,819	540	Cost of goods sold
	$(105)	$1,015	$787	

18. RETIREMENT PLAN

We sponsor 401(k) plans for substantially all employees. At December 31, 2015, we maintained legacy plans from our predecessor and the legacy plan from Direct Fuels. The plans are comparable generally in terms of employee eligibility, participation, and benefits. The plans provide for us to match 100% of the participants' contributions for a maximum of 5% matching under a single plan. Additionally, we can make discretionary contributions as deemed appropriate by management. Our employer contributions to these plans totaled $0.8 million, $0.7 million, and $0.4 million for the years ended December 31, 2015, 2014, and 2013, respectively.

19. SUPPLEMENTAL CASH FLOW DISCLOSURES

The following supplemental disclosures may assist in the understanding of our Consolidated Statements of Cash Flows:

	Year Ended December 31,		
	2015	2014	2013
	($ in thousands)		
Cash paid for interest	$12,755	$5,942	$5,866
Cash paid for income taxes, net of refunds	$937	$423	$159
Purchases of PP&E and intangible assets accrued but not paid at year-end	$4,364	$5,238	$1,641
Purchases of PP&E accrued in a prior period and paid in the current period	$5,238	$1,641	$9,455
Distribution equivalent rights accrued, net of payments	$618	$1,164	$372
Capitalized reclamation costs, net of amounts acquired in business combination	$113	$706	$721
Deferred compensation expense	$—	$122	$6,368

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANT ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures, as such term is defined under Rule 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended, or the Exchange Act. Based on that evaluation, our management, including our Chief Executive Officer and our Chief Financial Officer, has concluded that the design and operation of our disclosure controls and procedures were adequate and effective as of the end of the period covered by this report.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) and 15(d) - 15(f) under the Exchange Act). Our internal control system is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Internal control over financial reporting includes reasonable assurance that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of management and the board of directors of our general partner; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on the financial statements.

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

Management assessed the effectiveness of our internal control over financial reporting, as of December 31, 2015, and has concluded that such internal control over financial reporting was effective as of that date. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission, or COSO, in the Internal Control-Integrated Framework (2013).

The effectiveness of our internal control over financial reporting as of December 31, 2015, has been audited by BDO USA, LLP, an independent registered certified public accounting firm, as stated in their attestation report included in this Annual Report on Form 10-K.

Changes in Internal Control over Financial Reporting

As disclosed in our previous periodic reports, beginning with our Annual Report on Form 10-K for year ended December 31, 2014, our disclosure controls and procedures were not effective, due to deficiencies in our internal control over financial reporting with respect to performing and documenting Information Technology and Sand Segment control activities. These deficiencies represented material weaknesses in internal control over financial reporting, such that there was a reasonable possibility that a material misstatement of our annual or interim financial statements would not have been prevented or detected on a timely basis. In management's assessment of internal controls, as of December 31, 2014, it concluded that deficiencies existed in several key areas that, individually or in combination with one another, may not have reasonably and timely detected or prevented a material misstatement in our financial reporting.

Our management, including the Chief Executive Officer and Chief Financial Officer, has been committed to remediating previously disclosed material weaknesses in internal control over financial reporting by enhancing and communicating existing controls requirements and introducing new controls at the Sand Segment for general accounting and procurement, and information technology areas as necessary. The following material weakness remediation activities are now accomplished:

- performed a qualitative and quantitative administrative headcount and competency gap analysis to determine the most appropriate level of staffing necessary to manage the complexity and quantity of transactions to successfully perform the required control activities in a manner that positions us to respond to external and internal demands;
- through selective hiring, we improved skill competencies in the areas of accounting, monitoring, and information technology;
- where appropriate, incorporated training of information technology and accounting personnel. In 2015, we have supplemented our personnel resources with a number of consulting resources experienced in controls and SOX compliance; and
- increased managerial monitoring activities in the areas of information technology general controls as well as Sand segment procurement controls, general accounting controls related to capital expenditures, and railcar lease acquisition costs.

As a result of completing their final testing of internal controls over financial reporting, management, including the Chief Executive Officer and the Chief Financial Officer, believes the plan has been successfully implemented, and the material weaknesses identified above have been remediated as of December 31, 2015. Management will continue to monitor the effectiveness of these actions and will make any changes and take such other actions deemed appropriate given the circumstances.

Except as described above, there were no changes in internal control over financial reporting during the quarter ended December 31, 2015 (as defined by Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors of Emerge Energy Services GP LLC, as General Partner of Emerge Energy Services LP and the Partners of Emerge Energy Services LP
Southlake, Texas

We have audited Emerge Energy Services LP's (the "Partnership") internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Emerge Energy Services LP's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Item 9A, Controls and Procedures . Our responsibility is to express an opinion on the Partnership's internal control over financial reporting based on our audit.

We conducted our audit 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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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

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

In our opinion, Emerge Energy Services LP maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Emerge Energy Services LP as of December 31, 2015 and 2014, and the related consolidated statements of operations, partners' equity, and cash flows for each of the three years in the period ended December 31, 2015 and our report dated February 29, 2016 expressed an unqualified opinion thereon.

/s/ BDO USA, LLP
Dallas, Texas
February 29, 2016

ITEM 9B. OTHER INFORMATION
None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE
Partnership Management
We are managed and operated by the directors and executive officers of our general partner, Emerge Energy Partners GP LLC. Our general partner is not elected by our unitholders and will not be subject to re-election in the future. 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 owes certain fiduciary duties to our unitholders as well as a fiduciary duty to its owners. Our general partner is 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's board of directors has nine directors, four of whom are independent as defined under the independence standards established by the NYSE. Our general partner's board of directors has affirmatively determined that Messrs. Clark, Kelly, and Gottfredson are independent as described in the rules of the Exchange Act. The NYSE does not require a listed publicly traded partnership, such as ours, to have a majority of independent directors on the board of directors of our general partner or to establish a compensation committee or a nominating committee.
Directors and Executive Officers
Directors are appointed for a term of one year and hold office until their successors have been elected or qualified or until the earlier of their death, resignation, removal, or disqualification. Officers serve at the discretion of the board.
The following table shows information for the directors and executive officers of our general partner.

Name	Age	Position
Ted W. Beneski	59	Chairman of the Board and Director
Rick Shearer	65	Chief Executive Officer and Director
Deborah Deibert	51	Chief Financial Officer
Warren B. Bonham	53	Vice President and Director
Nadya Kurani	42	Chief Accounting Officer
Kevin Clark	59	Independent Director
Mark Gottfredson	58	Independent Director
Peter Jones	58	Independent Director
Francis Kelly	59	Independent Director
Eliot Kerlin	41	Director
Victor L. Vescovo	50	Director

Ted W. Beneski
Ted W. Beneski was elected Chairman of the Board and appointed as a member of the board of directors of our general partner in April 2012. Since May 2002, Mr. Beneski has served as the Chief Executive Officer and Managing Partner of Insight Equity Holdings LLC. Insight Equity has $1.3 billion of capital under management. Mr. Beneski also serves as Chairman of the Board of Direct Fuels and SSS, positions he has held since May 2003 and June 2008, respectively. Prior to founding Insight Equity, Mr. Beneski was a founding principal of the Carlyle Management Group, a private equity group specializing in investments in turnarounds and special situation investment opportunities, and served as Senior Vice President from January 2000 to May 2002. Mr. Beneski was also co-founder of the Dallas office of Bain & Company, or Bain, a global leader in strategy-based management consulting services, and served as a Senior Partner and Managing Director. His tenure at Bain (both in Boston and Dallas) was from September 1985 to December 1999. While at Bain, Mr. Beneski advised Fortune 100 clients across a wide range of

industries in the areas of portfolio and business unit strategy, mergers and acquisitions, operational improvement, organizational and process redesign, new product introduction and growth strategy. Prior to his time at Bain, Mr. Beneski worked for five years as a commercial banker with Bankers Trust in New York and Shawmut Corporation in Boston.

Mr. Beneski also serves as Chairman of the Board at the following Insight Equity portfolio companies: Vision Partners, Hirschfeld Industries, Walker Group Resources, Aviation Investment Holdings, Atwood Holdings, BFN Holdings, Versatile Processing Group Holdings, A.P. Plasman, New Star Metals Holdings, and MB Precision Holdings. Mr. Beneski also serves on the Board of Trustees of Amherst College and Trinity University. Mr. Beneski received his MBA from Harvard Business School and a BA from Amherst College, majoring in economics.

Mr. Beneski was selected to serve on the board of directors of our general partner due to his affiliation with Insight Equity, his knowledge of the industries in which we operate and his financial and business expertise.

Rick Shearer

Rick Shearer was elected Chief Executive Officer of our general partner in April 2012. Since May 2010, Mr. Shearer has served as President and Chief Executive Officer of SSS. In May 2014 Mr. Shearer was elected to serve on the board of directors of our general partner. Mr. Shearer previously served from March 2007 to May 2010 as President and Chief Executive Officer of Black Bull Resources, a company that specializes in the mining, processing and marketing of industrial minerals that is publicly traded on the TSX Venture Exchange. Mr. Shearer currently serves as the Chairman of the Board of Black Bull Resources. From January 2004 to March 2007, Mr. Shearer served as Director of Excell Minerals, a global stainless steel metals recovery company based in Pittsburgh, Pennsylvania, prior to its acquisition by Harsco Corporation in February 2007. Mr. Shearer also previously served as the President and Chief Operating Officer of U.S. Silica Company Inc., a silica sand supplier, from August 1997 to January 2004.

Mr. Shearer served as Founding Chairman of the Industrial Minerals Association of North America, as Vice Chairman of the National Industrial Sand Association and as a Board Member of the Industrial Minerals Association of Europe from 2003 to 2004. Mr. Shearer has a Bachelor of Science degree from Alderson-Broaddus College and a Masters of Business Administration degree from Eastern Michigan University. He is also a graduate of the Executive Management Program at Harvard University.

Deborah Deibert

Deborah Deibert was elected Chief Financial Officer of our general partner in February 2016. Prior to her election as Chief Financial Officer, Ms. Deibert served as the Chief Accounting Officer of the general partner and as Director of Financial Reporting prior to that role. Prior to her employment with the general partner, Ms. Deibert served as the Senior Director of Financial Reporting of FTS International, Inc. from 2011 until 2013. From 2007 until 2011, Ms. Deibert was Senior Director of SEC Reporting & International Finance of Blockbuster Inc. and previously has held various finance and accounting positions since 1988. Ms. Deibert holds a B.B.A. in accounting from the University of Texas at Arlington. She is licensed as a Certified Public Accountant in the state of Texas.

Warren B. Bonham

Warren B. Bonham was elected Vice President and appointed as a member of the board of directors of our general partner in April 2012 and currently manages the operations of our Fuel segment. Since February 2012, Mr. Bonham has been a Partner of Insight Equity Holdings LLC. Additionally, he has served as President and Chief Executive Officer of Direct Fuels since January 2008 and previously served as President from June 2006 to December 2007. Mr. Bonham also previously served as Vice President of Hirschfeld Steel, a company that specializes in the fabrication of structural steel components for construction projects such as bridges, industrial and nuclear facilities, mass transit systems, and stadiums, from September 2010 to January 2012 and from June 2006 to December 2007. From August 2002 to May 2006, Mr. Bonham served as the Chief Financial Officer of GES Exposition Services, the largest subsidiary of Viad Corporation, a publicly traded exhibition and event services company. Prior to joining GES Exposition Services, Mr. Bonham served as Chief Financial Officer of Electrolux LLC, a private equity owned direct seller of floor care equipment, from August 1998 to July 2002. From 1995 to 1998, Mr. Bonham worked as a Senior Manager at Bain, where he worked on operational improvement cases in many different industries on three different continents.

Mr. Bonham serves on the board of directors at a number of Insight Equity's portfolio companies including AEC and SSS prior to our initial public offering. Mr. Bonham received his MBA from Harvard Business School and his Bachelor of Commerce degree from Queen's University where he graduated first in his class. He is also a licensed

Chartered Accountant. Mr. Bonham was selected to serve on the board of directors of our general partner due to his affiliation with Insight Equity, his knowledge of the industries in which we operate and his financial and business expertise.

Nadya Kurani

Nadya Kurani was elected Chief Accounting Officer of our general partner in February 2016. Prior to her election as Chief Accounting Officer, Ms. Kurani served as the Director of Financial Reporting of the general partner and as Financial Reporting Manager prior to that role. Prior to her employment with the general partner, Ms. Kurani served as Financial Reporting Manager of Dave & Buster's Entertainment, Inc. from April 2013 to November 2014. Prior to that role, Ms. Kurani served at American Eagle Airlines as Accounting Manager from February 2012 to April 2013 and Financial Reporting Manager from June 2011 to January 2012. From September 2009 to June 2011, Ms. Kurani served as Financial Reporting Manager at Thomas Group, Inc. and previously has held various accounting positions since 2003. Ms. Kurani holds a B.B.A. in accounting from Midwestern State University. She is licensed as a Certified Public Accountant in the state of Colorado.

Kevin Clark

Kevin Clark has served as a member of our board of directors since March 2013. From January 2002 to May 2014 he taught classes in corporate strategy and accounting at Vanderbilt University as an Adjunct Professor, a Senior Lecturer and an Associate Professor. Prior to joining the faculty at Vanderbilt, Mr. Clark was a partner at Executive Perspectives Inc., an executive education firm focused on strategy, finance and team building, from October 1985 to November 1998. He is the co-managing partner of RG Clark Family Holdings, LLC, serving in that role since November 2011, and also serving as Secretary and Treasurer from September 2000 to the present. He is also a Director for three small private companies: Sullivan Street Development, Inc. since June 2001, Exit 33, Inc. since January 2014, and Pulaski Properties, Inc., Director and President since June 2014.

Mr. Clark holds a B.S. in physics from Amherst College and an M.S. in computer and information science from Dartmouth College. Mr. Clark was chosen to serve on the board of our general partner due to his expertise in corporate strategy and accounting.

Peter Jones

Peter Jones joined our board of directors in May of 2014. He is the CEO of Flanders Corporation, a leader in the air filtration industry, a position he has held since July of 2014. Since 2009, Mr. Jones has served as an independent advisor to the owners of a number of private companies while they evaluated investment opportunities, handled the operational impacts of rapid growth, reviewed management compensation plans and other deals with assorted issues. During this time, he was on occasion made an employee of employee leasing companies, such as from March to October 2009 as part of Prestige Employee Administrators and from October 2012 to October 2014 as part of Genesis HR Solutions, Inc. Prior to this period of independent contracting, Mr. Jones was involved in the management at a number of private companies, primarily those owned by venture capital and private equity firms.

From 2002 to 2008 he was the Chief Executive Officer of Prime Advantage Corporation, whose two business units included an industrial buying group and a logistics company. From 2005 to 2007, he was Chief Executive Officer of Longstreth Women's Sports LLC, one of the leading importers and retailers of field hockey, lacrosse, and softball equipment. From 2000 to 2002 he was Chief Executive Officer and President of Stratys Learning Solutions, Inc., which offered masters level degrees in technical fields though distance learning, as well as professional development courses. Mr. Jones has also run or overseen the transformation of companies in the health care, corporate training, laser, computer sales and service, consumer goods and e-commerce software industries. Mr. Jones spent three years at the start of his career with Bankers Trust Company, including a year-long classroom training program focused on accounting and finance. During and after his MBA, Mr. Jones worked for Bain and Company in their Boston office, evaluating potential acquisitions, operational enhancements, and studying the venture capital and leveraged buy-out industries.

Mr. Jones received his MBA with high distinction from Harvard Business School, where he was a Baker Scholar. He also holds a B.A. and an M.A. from the University of Oxford, where he studied Mathematics. He also serves as a Board Member and President of the United States Men's Field Hockey Foundation and as a Board Member of the International Masters Hockey Association, both of which are non-profit organizations. Mr. Jones was chosen to serve on the board of our general partner due to his expertise with high growth companies and companies in transition.

Francis J. Kelly, III

Francis J. Kelly, III was appointed as an independent director of our general partner in March 2013. Mr. Kelly is President and CEO of CEOVIEW Branding LLC, a brand strategy consulting firm. Prior to forming CEOVIEW, Mr. Kelly was with Arnold Worldwide, LLC a large advertising agency. Mr. Kelly joined Arnold Worldwide in January 1994 as Chief Marketing officer, and advanced to become President in 2002, CEO in 2006, and eventually Vice Chairman in 2010 until his resignation in 2014. Mr. Kelly has led a number of successful branding strategies for public and private companies while helping Arnold Worldwide shape its strategic and creative philosophy. From 1989 to 1994, Mr. Kelly worked at Leonard Monahan and Lubars, an advertising agency subsequently renamed Leonard Monahan Lubars and Kelly. From 1983 to 1988, Mr. Kelly developed integrated campaigns for national brands while working for Humphrey Browning MacDougall. His career in the field of branding, advertising, and integrated marketing communications also includes time at Young & Rubicam New York.

Mr. Kelly received his MBA from Harvard Business School and his Bachelor of Arts degree from Amherst College. He is the co-author of two business books and has previously served on the boards of the Boston Chamber of Commerce, the Friends of the Boston Public Library, the Boston Ad Club and the American Association of Advertising Agencies. Mr. Kelly was selected to serve on the board of directors of our general partner due to his marketing, financial and business expertise.

Mark Gottfredson
Mark Gottfredson was appointed to the Board as independent director of our general partner in March 2015. Mr. Gottfredson was also appointed a member of the Audit Committee of the Board. Mr. Gottfredson is currently a director of Bain & Company's office in Dallas, Texas, which he founded in 1990. Throughout his career, he has advised chief executives and top-level managers in a wide range of industries. He has served in a number of leadership positions at Bain & Company including as a member of the board of directors and as the Global Head of Bain's Performance Improvement Practice. In 2005, Mr. Gottfredson was named to Consulting Magazines list of Top 25 Consultants globally. He has been published extensively in publications such as the Harvard Business Review, European Strategy, and the World Business Review. His book for general managers, titled The Breakthrough Imperative and published by Harper Collins, debuted in spring 2008. Mr. Gottfredson serves on a number of for profit and non-profit boards, including Vista Outdoor Inc., TBM Consulting Group, the Circle 10 Council with the Boy Scouts of America, the Longhorn Council for the Boy Scouts of America, the BYU Marriot School National Advisory Council, and Bain & Company.
Mr. Gottfredson obtained his M.B.A. from Harvard Business School in 1981, where he graduated with high distinction and was named a Baker Scholar. He received a Bachelor of Arts degree from Brigham Young University in Japanese, where he graduated magna cum laude. Mr. Gottfredson was selected to serve on the Board of the general partner due to his advisory experience and financial and business expertise.
Eliot E. Kerlin, Jr.
Eliot E. Kerlin Jr. was appointed as a member of the board of directors of our general partner in March 2013.
Mr. Kerlin is a Partner at Insight Equity Holdings LLC and has been a member of the firm since July 2005. During his time at Insight Equity Holdings LLC, Mr. Kerlin has led a number of acquisitions, recapitalizations, financings, and operational improvement initiatives at portfolio companies. During 2004, Mr. Kerlin served as a turnaround manager for Bay State Paper Company, a containerboard and craft paper manufacturer. From 2000 to 2003, Mr. Kerlin worked as a Senior Associate at Jupiter Partners, a middle market private equity fund. He began his career as an investment banker at Merrill Lynch Pierce Fenner & Smith.
Mr. Kerlin currently serves as an Executive Vice President and board member for a number of Insight Equity's portfolio companies, including SSS., He received his MBA from Harvard Business School and his Bachelor of Business Administration degree in finance from Texas A&M University. Mr. Kerlin also serves on several non-profit, community and professional boards of directors. Mr. Kerlin was selected to serve on the board of directors of our general partner due to his affiliation with Insight Equity, his knowledge of the industries in which we operate and his financial and business expertise.
Victor L. Vescovo
Victor L. Vescovo was appointed as a member of the board of directors of our general partner in April 2012. Since January 2003, Mr. Vescovo has served as the Chief Operating Officer and Managing Partner of Insight Equity Holdings LLC, which he co-founded with Mr. Beneski. From 1999 to 2001, Mr. Vescovo was Vice President of Product Development of Military Advantage, a venture-backed company sold to Monster Worldwide, Inc. in 2004. From 1994 to 1999, he was a Senior Manager at Bain where he focused on merger integration and operational improvement cases. Mr. Vescovo previously worked in the mergers & acquisitions department of Lehman Brothers Holdings Inc. where he was responsible for company due diligence and transaction execution, as well as working overseas in the Middle East advising the Saudi government on business investments from 1991 to 1992.
Mr. Vescovo also serves as a board member of all of Insight Equity's portfolio companies, including Allied Energy Company and Superior Silica Sands. Mr. Vescovo received his MBA from the Harvard Business School where he graduated as a Baker Scholar. He also received a Master's Degree from the Massachusetts Institute of Technology and earned a double major Bachelor of Arts in economics and political science from Stanford University.
Additionally, Mr. Vescovo served 20 years in the U.S. Navy (Reserve) with specialties in operational targeting and counter-terrorism, retiring in the fall of 2013 with the rank of Commander (O-5). Mr. Vescovo was selected to serve on the board of directors of our general partner due to his affiliation with Insight Equity, his knowledge of the industries in which we operate and his financial and business expertise.

Corporate Governance

The board of directors of our general partner has adopted corporate governance guidelines to assist it in the exercise of its responsibilities to provide effective governance over our affairs for the benefit of our unitholders. In addition, we have adopted a code of business conduct and ethics, which sets forth legal and ethical standards of conduct for all our officers, directors, and employees. The corporate governance guidelines, the code of business conduct and ethics and the charters of our audit and conflicts committees are available on our website at www.emergelp.com and in print without charge to any unitholder who requests any of them. A unitholder may make such a request in writing by mailing such request to Deborah Deibert at Investor Relations, Emerge Energy Services LP, 180 State Street, Suite 225, Southlake, Texas 76092. Amendments to, or waivers from, the code of business conduct and ethics will also be available on our website and reported as may be required under SEC rules; however, any technical, administrative or other non-substantive amendments to the code of business conduct and ethics may not be posted. Please note that the preceding Internet address is for information purposes only and is not intended to be a hyperlink. Accordingly, no information found or provided at that Internet address or at our website in general is intended or deemed to be incorporated by reference herein.

Conflicts Committee

Our partnership agreement provides for the Conflicts Committee, as circumstances warrant, to review conflicts of interest between us and our general partner or between us and affiliates of our general partner. The Conflicts Committee, consisting solely of independent directors, determines if the resolution of a conflict of interest that has been presented to it by our general partner is fair and reasonable to us. The members of the Conflicts Committee may not be executive officers or employees of our general partner or directors, executive officers or employees of its affiliates. In addition, the members of the Conflicts Committee must meet the independence and experience standards established by the NYSE and the Exchange Act. Messrs. Clark and Kelly serve as the members of the Conflicts Committee. Mr. Kelly serves as the chair of our Conflicts Committee.

Audit Committee

The board of directors of our general partner has established an audit committee, or Audit Committee, that complies with the NYSE requirements and Section 3(a)(58)(A) of the Exchange Act. Our general partner is generally required to have at least three independent directors serving on its board at all times. Messrs. Clark, Kelly, and Gottfredson are independent directors and serve as the members of the Audit Committee. The board of directors of our general partner has also determined that Mr. Clark, who serves as the chairman of the Audit Committee, and also Messrs. Kelly and Gottfredson, each have such accounting or related financial management expertise sufficient to qualify him as an audit committee financial expert in accordance with Item 407(d) of Regulation S-K.

The Audit Committee meets on a regularly scheduled basis with our independent accountants at least four times each year and is available to meet upon the request of any committee member. The Audit Committee has the authority and responsibility to review our external financial reporting, to review our procedures for internal auditing and the adequacy of our internal accounting controls, to consider the qualifications and independence of our independent accountants, to engage and resolve disputes with our independent accountants, including the letter of engagement and statement of fees relating to the scope of the annual audit work and special audit work that may be recommended or required by the independent accountants, and to engage the services of any other advisors and accountants as the Audit Committee deems advisable. The Audit Committee reviews and discusses the audited financial statements with management, discusses with our independent auditors matters required to be discussed by Public Company Accounting Oversight Board Auditing Standard No. 16 (Communications with Audit Committees) and Rule 3520 (Auditor Independence), and makes recommendations to the board of directors of our general partner regarding the inclusion of our audited financial statements in this Annual Report on Form 10-K.

The Audit Committee is authorized to recommend periodically to the board of directors any changes or modifications to its charter that the Audit Committee believes may be required or desirable.

Presiding Director at Meetings of Non-Management Directors.

Section 303A.03 of the NYSE Listed Company Manual requires “non-management directors” to schedule regular executive sessions with members of management present. “Non-management directors” are defined in Section 303A.03 as all directors who are not executive officers. The Partnership schedules executive sessions on a regular basis in which the Partnership's non-management directors meet without management participation. Mr. Kevin Clark serves as the presiding director at such sessions. The Board of Directors is responsible for determining whether or not each director is independent. The Board of Directors has adopted the director independence standards contained in Section 303A.02 of the NYSE’s Listed Company Manual for the purposes of satisfying the NYSE’s applicable governance requirements.

Communication with the Board of Directors

A holder of our units or other interested party who wishes to communicate with the non-management directors or independent directors of our general partner may do so by writing in an envelope marked “Confidential” to the Independent Members of the Board, at 180 State Street, Suite 225, Southlake, Texas 76092.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires our general partner's board of directors and executive officers, and persons who own more than 10 percent of a registered class of our equity securities, to file with the SEC and any exchange or other system on which such securities are traded or quoted initial reports of ownership and reports of changes in ownership of our common units and other equity securities. Officers, directors and greater than 10 percent unitholders are required by the SEC's regulations to furnish to us and any exchange or other system on which such securities are traded or quoted with copies of all Section 16(a) forms they filed with the SEC. To our knowledge, based solely on a review of the copies of such reports furnished to us and written representations that no other reports were required, we believe that all reporting obligations of our general partner's officers, directors and greater than 10 percent unitholders under Section 16(a) were satisfied during the year ended December 31, 2015, except as described below.

Due to administrative oversight, Mr. Shearer did not timely report gifts of common units made on November 19, 2014, January 7, 2015 and June 24, 2015. In addition, due to administrative oversight, a Form 4 filed by Mr. Shearer in connection with the grant of restricted units and performance based phantom units made on July 1, 2015 was not timely filed. Mr. Shearer reported these grants and the gift transaction in Forms 4 filed on July 7, 2015 and February 26, 2016.

Due to administrative oversight, a Form 3 filed by Ms. Deibert in connection with her election as Chief Accounting Officer of our general partner effective November 13, 2015 was not timely filed. Ms. Deibert filed the Form 3 on November 24, 2015.

ITEM 11. COMPENSATION DISCUSSION AND ANALYSIS

The board of directors of our general partner develops our executive compensation policies and determines the amounts and elements of compensation for our named executive officers. This Compensation Discussion and Analysis describes our executive compensation programs for our named executive officers for the 2015 fiscal year, who were:

- Rick Shearer, Chief Executive Officer of Emerge Energy Services GP LLC, our general partner;
- Robert Lane, former Chief Financial Officer of our general partner;
- Joseph C. Tusa, Jr., Chief Financial Officer of our general partner;
- Warren Bonham, Vice President of our general partner;
- Richard DeShazo, former Chief Accounting Officer of our general partner; and
- Deborah Deibert, Chief Accounting Officer of our general partner.

On May 1, 2015, Mr. Lane resigned as Chief Financial Officer of our general partner. Mr. Lane continued to serve our general partner until May 31, 2015 to ensure a smooth transition as his successor took over his duties as Chief Financial Officer. On May 4, 2015, the board of directors of our general partner appointed Mr. Tusa as Chief Financial Officer of our general partner. On November 13, 2015, Mr. DeShazo retired as Chief Accounting Officer of our general partner and Ms. Deibert was elected as Chief Accounting Officer of our general partner. On January 29, 2016, Mr. Tusa tendered his resignation as Chief Financial Officer of our general partner, and on February 8, 2016, Ms. Deibert was appointed as Chief Financial Officer of our general partner.

Compensation Principles and Objectives

Our overall compensation program is structured to attract, motivate and retain highly qualified executive officers by paying them competitively, consistent with our success and their contribution to that success. Our ability to excel depends on the skill, creativity, integrity, and teamwork of our employees. We believe compensation should be structured to ensure that a portion of compensation opportunity will be related to factors that directly and indirectly influence long-term unitholder value. Our compensation philosophy has been driven by a number of factors that are closely linked with our broader strategic objectives.

The board of directors of our general partner believes that compensation paid to our named executive officers should be aligned with our performance on both a short-term and long-term basis, linked to results intended to create value for unitholders, and that such compensation should assist us in attracting and retaining key executives critical to our long-term success.

In establishing compensation for executive officers, the following are the objectives of the board of directors of our general partner:

- align officer and unitholder interests by providing a significant portion of total compensation opportunities for senior management in the form of equity awards and bonuses awarded based on the board of directors of our general partner’s review of company and individual performance; and
- ensure executive officer compensation is competitive within the marketplace in which we compete for executive talent by relying on the board of directors of our general partner’s judgment, expertise and personal experience with other similar companies.

Determination of Compensation

The board of directors of our general partner is charged with the primary authority to determine the compensation available to our executive officers. Based on the directors' collective understanding of compensation practices in similar companies in the frac sand and fuel processing and distribution industries, our executive compensation package consists of the following elements, in addition to the employee benefit plans in which all employees may participate:

- Base salary: compensation for ongoing services throughout the year.

- Annual performance-based compensation and discretionary bonuses: annual incentive bonus based on the achievement of pre-established targets and/or discretionary objectives, each to recognize and reward achievement of corporate and individual performance.
- Long-term incentive compensation programs: equity compensation to provide an incentive to our named executive officers to manage us from the perspective of an owner with an equity stake in the business.
- Severance and change in control benefits: remuneration paid to certain executives in the event of a qualifying termination of employment and/or change in control.

To aid the board of directors of our general partner in making its determination, our Chief Executive Officer provides recommendations annually to the board of directors of our general partner regarding the compensation of all other executive officers (other than himself) based on the overall corporate achievements during the period being assessed and his knowledge of the individual contributions to our success by each of the named executive officers. The overall performance of our named executive officers as a team is reviewed annually by the board of directors of our general partner.

We set base salary and annual bonus structures and determine grants of equity awards based on the board of directors of our general partner's understanding of compensation practices in the frac sand and fuel processing and distribution industries and such directors' experiences as seasoned executives, consultants, members of the board of directors of our general partner, or investors in similar frac sand and fuel processing and distribution industries companies. In addition, from time to time we may rely on compensation survey data provided by an independent compensation consultant.

Elements of Executive Compensation

Base Salaries

Base salaries of our named executive officers (other than our Chief Executive Officer) are recommended and reviewed periodically by our Chief Executive Officer, and the base salary for each named executive officer is approved by the board of directors of our general partner. Base salaries for the named executive officers are reviewed periodically by the board of directors of our general partner, and adjustments are made generally in accordance with the considerations described above and to maintain base salaries at competitive levels. These periodic reviews consider, among other things, the scope of an executive's responsibilities, individual contribution, experience and sustained performance, general economic conditions, industry specific business conditions, base salaries for comparable positions in similar industries, the tenure of the officers, and base salaries of the officers relative to one another. Decisions regarding salary increases may take into account the named executive officer's current salary and other compensation, and the amounts paid to individuals in comparable positions at our peer companies.

Mr. Shearer is entitled to a formulaic base salary increase of at least 4 percent each year based on satisfactory execution of applicable business goals. Mr. Shearer received a salary adjustment in excess of that minimum target effective on July 1, 2015. As a result, no additional increase in Mr. Shearer's salary was made at the beginning of 2016

In January 2015, the board of directors of our general partner approved base salary increases for Messrs. Shearer, Lane, Bonham, and DeShazo of 6%, 2%, 5% and 5%, respectively, effective January 1, 2015. These increases were determined primarily based on consideration of general industry base pay increase trends for executives as reported by our independent compensation consultant. The board of directors of our general partner believed these increases in base salary were appropriate based on each executive's individual achievements in 2014. In addition, on June 29, 2015, the board of directors of our general partner approved the increase to the annual base salary of Mr. Shearer from $450,000 to $500,000, effective July 1, 2015, to more closely align Mr. Shearer's annual base salary to the base salaries of his peers in the marketplace. In connection with Ms. Deibert's appointment as Chief Accounting Officer of our general partner, Ms. Deibert's annual base salary was increased from $200,850 to $225,000, effective September 28, 2015.

Named Executive Officer	2015 Annual Base Salary
Rick Shearer (1)	$500,000
Robert Lane (1)	$279,100
Joseph C. Tusa, Jr.	$335,000
Warren Bonham	$200,000
Richard DeShazo	$245,700

Deborah Deibert (2)	$225,000

(1) Mr. Shearer's annual base salary was increased from $450,000 to $500,000 effective July 1, 2015.
(2) Ms. Deibert's annual base salary was increased from $200,850 to $225,000 effective September 28, 2015.

The actual base salaries paid to our named executive officers during 2015 are set forth in the "Summary Compensation Table" below.

In February 2016, in connection with Ms. Deibert's appointment as Chief Financial Officer of our general partner, Ms. Deibert's annual base salary was increased from $225,000 to $280,000.

Annual Bonuses

In addition to base salaries, our executives are also eligible to receive annual incentive bonuses. For 2015, annual incentive bonuses were targeted at the percentage of each executive's annual base salary shown below. Additionally, the board of directors of our general partner may award discretionary bonuses based on company and individual performance.

Named Executive Officer	2015 Target Bonus as a Percent of Base Salary
Rick Shearer	80%
Robert Lane	50%
Joseph C. Tusa, Jr.	75%
Warren Bonham	40%
Richard DeShazo	45%
Deborah Deibert	45%

For 2015, each of our named executive officers was eligible to receive an annual incentive bonus based on achievement of pre established adjusted EBITDA targets. Mr. Shearer's annual incentive bonus was determined based on adjusted EBITDA results for SSS; Ms. Deibert's and Messrs. Lane's, Tusa's and DeShazo's annual incentive bonuses were determined (or would have been determined, as applicable) based on adjusted EBITDA results for Emerge; and Mr. Bonham's annual incentive bonus was determined based on the individual adjusted EBITDA results for Direct Fuels and AEC (weighted equally). The applicable threshold and target levels and associated payouts are listed below, with achievement between the threshold level and target level determined by straight-line interpolation. There was no maximum funding level under the 2015 annual incentive bonus plan.

Named Executive Officer	Adjusted EBITDA	Payout (as a percentage of base salary) (1)
Rick Shearer		
Threshold	$145,000,000	10%
Target	$180,000,000	80%
Maximum	(1)	(1)
Robert Lane (1)		
Threshold	$167,000,000	10%
Target	$187,000,000	50%
Maximum	(1)	(1)
Joseph C. Tusa, Jr.		
Threshold	$167,000,000	10%
Target	$187,000,000	75%
Maximum	(1)	(1)
Warren Bonham (Direct Fuels incentive) (2)		
Threshold	$4,100,000	5%
Target	$7,100,000	20%
Maximum	(1)	(1)
Warren Bonham (AEC incentive) (2)	$11,250,000	5%
Threshold	$13,500,000	20%
Target	(1)	(1)
Maximum		
Richard DeShazo		
Threshold	$167,000,000	9%
Target	$187,000,000	45%
Maximum	(1)	(1)
Deborah Deibert		
Threshold	$167,000,000	9%
Target	$187,000,000	45%
Maximum	(1)	(1)

(1) There was no maximum funding level under the 2015 annual incentive bonus plan.

(2) Mr. Bonham's annual incentive bonus was determined based on the individual adjusted EBITDA results for Direct Fuels and AEC (weighted equally).

Based on the 2014 adjusted EBITDA achieved by SSS ($121.9 million), Direct Fuels ($7.9 million) and Emerge ($131.9 million), we awarded the following cash bonuses to our named executive officers:

Named Executive Officer	2014 Bonus	2014 Bonus (as percentage of base salary)
Rick Shearer	$928,886	219%
Robert Lane	$384,178	142%
Warren Bonham	$35,727	18%
Richard DeShazo	$298,972	128%

Based on the 2015 adjusted EBITDA achieved by SSS ($46.9 million), Mr. Shearer was not eligible to receive an annual incentive bonus. Based on the 2015 adjusted EBITDA achieved by Direct Fuels ($4.1 million), Mr. Bonham was eligible to receive an annual incentive bonus equal to $14,151. Mr. Bonham was not eligible to receive an annual incentive bonus with respect to the AEC component of his 2015 bonus program because AEC's adjusted EBITDA ($5.9 million) failed to achieve the minimum funding threshold. Based on the 2015 adjusted EBITDA achieved by Emerge ($48.4 million), Ms. Deibert was not eligible to receive an

annual incentive bonus. Messrs. Lane, Tusa, and DeShazo were not eligible to receive an annual incentive bonus because these executives either terminated their employment or retired prior to payment of annual incentive bonuses for the 2015 fiscal year.

We also paid discretionary bonuses to Messrs. Shearer, Tusa, and DeShazo and to Ms. Deibert based on each executive's strong individual performance in the current market environment or in connection with transition services, as illustrated in the following table.

Named Executive Officer	2015 Annual Incentive Bonus	2015 Individual Performance or Transition Bonus	2015 Bonus (as percentage of base salary)
Rick Shearer (1)	—	$15,000	3.0%
Robert Lane	—	—	—
Joseph C. Tusa, Jr. (2)	—	$6,663	2.0%
Warren Bonham	$14,151	—	6.7%
Richard DeShazo (3)	—	$200,000	81.4%
Deborah Deibert (1)	—	$6,750	3.0%

(1) We paid a 3% individual performance bonus to Mr. Shearer ($15,000) and Ms. Deibert ($6,750) based on their respective annual base salaries on December 31, 2015.

(2) We paid a 3% individual performance bonus to Mr. Tusa ($6,663) based on his base annual salary on December 31, 2015 (prorated to reflect his starting date of May 4, 2015).

(3) For transition services provided to our general partner, we paid Mr. DeShazo a one-time bonus equal to $200,000 on November 27, 2015.

Lane Long-Term Incentive Compensation Program

Prior to his termination of employment, Mr. Lane was eligible to participate in two long-term incentive programs. Under the first program (the "Distribution LTIC"), Mr. Lane was eligible to receive a cash bonus each year based on the amount by which our regular annual distribution exceeded $58,049,200. Under the second program (the "Unit Price LTIC"), Mr. Lane was eligible to receive a cash bonus each year based on the amount by which the average daily trading value of our common units for the applicable year exceeded the per unit equity value of our common units upon the completion of our IPO. Each of the Distribution LTIC and the Unit Price LTIC were scheduled to be paid in a cash lump sum amount after December 31, 2015 (but no later than March 15, 2016), subject to Mr. Lane's continued employment though December 31, 2015. At the time of his termination, Mr. Lane remained eligible to receive a cash payment of $146,096 under the Distribution LTIC and the Unit Price LTIC for 2013, which we paid to him as part of his separation arrangement.

Equity Awards

The goals of our long-term, equity-based incentive awards are to align the interests of our named executive officers with the interests of our common unitholders. Because vesting is generally based on continued service, our equity-based incentives also encourage the retention of our named executive officers during the award vesting period. In determining the size of the long-term equity incentives to be awarded to our named executive officers, we take into account a number of factors, such as the reason for the grant, the value of existing equity-based awards (if any), individual performance history, and prior financial contributions to us.

To reward and retain our named executive officers in a manner that aligns their interests with our unitholders' interests, we have historically used phantom units as the incentive vehicle for long-term compensation. We have granted phantom units in connection with specific events, such as our IPO or in lieu of other forms of compensation. Because employees realize increased value from phantom units if our unit price increases, we believe phantom units provide meaningful incentives to achieve increases in the value of our units over time. Grants of phantom units are typically accompanied by grants of distribution equivalent rights ("DERs"), which entitle the holder of the award to receive distributions in an amount equal to any distributions to our common unitholders.

Phantom unit awards are typically subject to time-based vesting conditions and/or performance-based vesting conditions related to our unit price. Vesting may also be tied to other conditions, such as the sale or disposition of common units held by Insight Equity following our IPO. In addition, phantom unit awards may be subject to accelerated vesting in connection with a change in control and/or upon a qualifying termination of service.

In January 2015, we granted Mr. Lane a phantom unit award covering 1,200 phantom units. The award was scheduled to vest in equal installments on the first, second, and third anniversaries of the vesting commencement date (January 1, 2015), subject to Mr. Lane's continued employment, or immediately prior to a change in control. Mr. Lane forfeited this phantom unit award, as well as the phantom unit awards which were granted to him in 2014, in connection with his termination of employment in May 2015.

In January 2015, we also granted Ms. Deibert a phantom unit award covering 600 phantom units. The phantom unit award will vest in equal installments on the first, second and, third anniversaries of the vesting commencement date (January 1, 2015), subject to her continued employment, or immediately prior to a change in control.
In May 2015, we granted Mr. Tusa two phantom unit awards each covering 2,619 units. The first phantom unit award was scheduled to vest in equal installments on the first, second, third and, fourth anniversaries of the vesting commencement date (May 4, 2015), subject to his continued employment or immediately prior to a change in control. In addition, if Mr. Tusa was terminated without cause, a prorated number of unvested phantom units would vest.
Mr. Tusa's second phantom unit award was scheduled to vest upon achievement of the following unit price targets, and subject to his continued employment:

- 50% of the units would vest on the date our per-unit closing price equaled or exceeded 1.5 times the per-unit closing price on the grant date ($38.18); and
- 50% of the units would vest on the date our per-unit closing price equaled or exceeded two times the per-unit closing price on the grant date.

Mr. Tusa forfeited both phantom unit awards in connection with his termination of employment in January 2016.
In July 2015, we granted Mr. Shearer two phantom unit awards each covering 13,623 units. The first phantom unit award will vest in equal installments on the first, second and, third anniversaries of the vesting commencement date (July 1, 2015), subject to his continued employment or immediately prior to a change in control. In addition, if Mr. Shearer is terminated without cause, a prorated number of unvested phantom units will vest.
Mr. Shearer's second phantom unit award will vest upon achievement of the following unit price targets, and subject to his continued employment:

- 50% of the units will vest on the date our per-unit closing price equals or exceeds 1.25 times the per-unit closing price on the grant date ($36.70); and
- 50% of the units will vest on the date our per-unit closing price equals or exceeds two times the per-unit closing price on the grant date.

In October 2015, in connection with her appointment to Chief Accounting Officer, we granted Ms. Deibert a phantom unit award covering 7,000 phantom units. The award will vest in equal installments on the first, second and, third anniversaries of the vesting commencement date (October 1, 2015), subject to her continued employment, or immediately prior to a change in control.
Neither Messrs. Bonham nor DeShazo received an equity award in 2015. Mr. DeShazo forfeited his unvested phantom unit awards in connection with his retirement in November 2015.

Severance and Change in Control Arrangements

Each of our named executive officers, other than Mr. Bonham, is (or was prior to the executive's termination of employment) eligible for severance benefits pursuant to their respective employment letters. We believe that this protection serves to encourage continued attention and dedication to duties without distraction arising from the possibility of a termination of employment or change in control, and provides the business with a smooth transition in the event of such a termination of employment. These severance arrangements are designed to retain these named executive officers in their respective key positions as we compete for talented executives in the marketplace where such protections are commonly offered. For a detailed description of the severance provisions contained in our named executive officers' employment letters, and other severance or change in control protections, see "Potential Payments Upon Termination or Change in Control" below. We do not offer Mr. Bonham severance benefits because of his association with Insight Equity.

Other Elements of Compensation and Perquisites

All of our full-time employees in the United States, including our named executive officers, are eligible to participate in our 401(k) plan and our health and welfare plans (including medical, dental, short-term and long-term disability, accidental death and dismemberment and life insurance). Our named executive officers participate in these plans on the same basic terms as all other similarly situated employees.
Through its subsidiaries, our general partner maintains a 401(k) retirement savings plans for its employees who satisfy certain eligibility requirements. Mr. Bonham does not participate in our 401(k) retirement savings plans because of his association with Insight Equity. The Internal Revenue Code of 1986, as amended (the "Code"), allows eligible

employees to defer a portion of their compensation, within prescribed limits, on a pre-tax basis through contributions to the 401(k) plan. We believe that providing a vehicle for tax-deferred retirement savings though a 401(k) plan, and making fully vested matching contributions, adds to the

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overall desirability of our executive compensation package and further incentivizes our employees, including the named executive officers, in accordance with our compensation policies.

In addition to the benefits provided to all of our full-time employees, Mr. Shearer is also entitled to receive company-paid annual physical exams, not to exceed $3,000 per year, which are supplemental to the health benefits provided to employees of our general partner generally.

In the future, we may provide perquisites or other personal benefits in limited circumstances, such as where we believe it is appropriate to assist an individual named executive officer in the performance of his duties, to make our named executive officers more efficient and effective, and for recruitment, motivation, and/or retention purposes. Future practices with respect to perquisites or other personal benefits for our named executive officers will be approved and subject to periodic review by the board of directors of our general partner.

Tax and Accounting Considerations

Section 280G of the Code

Section 280G of the Code disallows a tax deduction with respect to excess parachute payments to certain executives of companies which undergo a change in control. In addition, Section 4999 of the Code imposes a 20% excise tax on the individual with respect to the excess parachute payment. Parachute payments are compensation linked to or triggered by a change in control and may include, but are not limited to, bonus payments, severance payments, certain fringe benefits, and payments and acceleration of vesting from long-term incentive plans including restricted units and other equity-based compensation. Excess parachute payments are parachute payments that exceed a threshold determined under Section 280G of the Code based on the executive’s prior compensation. In approving the compensation arrangements for our named executive officers in the future, the board of directors of our general partner will consider all elements of the cost to the Company of providing such compensation, including the potential impact of Section 280G of the Code. However, the board of directors of our general partner may, in its judgment, authorize compensation arrangements that could give rise to loss of deductibility under Section 280G of the Code and the imposition of excise taxes under Section 4999 of the Code when it believes that such arrangements are appropriate to attract and retain executive talent.

Accounting Standards

ASC Topic 718, Compensation-Stock Compensation (“ASC Topic 718”) requires us to recognize an expense for the fair value of equity-based compensation awards. Grants of phantom units and restricted units under our equity incentive award plan are accounted for under ASC Topic 718. The board of directors of our general partner regularly considers the accounting implications of significant compensation decisions, especially in connection with decisions that relate to our equity incentive award plan. As accounting standards change, we may revise certain programs to appropriately align accounting expenses of our equity awards with our overall executive compensation philosophy and objectives.

Summary Compensation Table

Name and Principal Position	Salary ($)	Bonus ($)(1)	Stock Awards ($)(2)	Non-Equity Incentive Plan Compensation ($)(3)	All Other Compensation ($)(4)	Total ($)
Rick Shearer						
Chief Executive Officer						
2015	475,000	15,000	999,928	—	28,223	1,518,151
2014	425,000	—	—	928,886	17,877	1,371,763
2013	312,940	—	9,019,996	4,653,499	11,582	13,998,017
Robert Lane						
Chief Financial Officer						
2015	123,459	—	64,800	—	433,980	622,239
2014	270,620	—	550,000	384,178	28,193	1,232,991
2013	256,000	153,000	—	—	22,083	431,083
Joseph C. Tusa, Jr. (2)						
Chief Financial Officer						
2015	212,596	6,663	199,987	—	101,240	520,486
Warren Bonham						
Vice President						
2015	210,000	—	—	14,151	3,665	227,816
2014	200,000	200,000	—	35,727	3,500	439,227
2013	136,577	1,130,080	2,049,996	—	—	3,316,653
Richard DeShazo (6)						
Chief Accounting Officer						
2015	222,075	200,000	—	—	59,448	481,523
2014	234,000	—	—	298,972	27,506	560,478
Deborah Deibert (8)						
Chief Accounting Officer						—
2015	206,423	6,750	67,260	—	14,864	295,297

(1) For 2015, Messrs. Shearer and Tusa and Ms. Deibert were paid discretionary bonuses of $15,000, $6,663, and $6,750, respectively, based on their individual performances. Mr. DeShazo was paid a transition bonus of $200,000 in connection with transition services related to his retirement in November 2015.

(2) The amounts illustrated in this column reflect the aggregate grant date fair value of phantom unit awards made in 2015. The values are calculated in accordance with GAAP. For a discussion of the assumptions used to calculate the value of all phantom unit awards made to named executive officers, refer to Note 12 to our financial statements included in this Annual Report on Form 10-K for the year ended December 31, 2015.

(3) For 2015, the amounts include annual incentive bonuses earned in connection with the achievement of pre-established adjusted EBITDA targets. Mr. Bonham’s bonus was determined based on adjusted EBITDA results for Direct Fuels. Annual incentive bonuses earned in 2015 were paid in 2016.

(4) The following table sets forth the amount of each other item of compensation paid to, or on behalf of, our named executive officers in 2015 included in the “All Other Compensation” column. Amounts for each other item of compensation are valued based on the aggregate incremental cost to us, in each case without taking into account the value of any income tax deductions for which we may be eligible.

Name	Company Contributions to 401(k) Plan ($)	Company Contributions to Health Savings Account ($)	Reimbursement for Executive Physical Allowance ($)	Severance Payments ($)	Payment for Unused Paid Time Off ($)	Reimbursement for Relocation, Moving and Temporary Living Costs ($) (1)
Rick Shearer	21,923	3,300	3,000	—	—	—
Robert Lane	17,500	1,523	—	398,854	16,103	—
Joseph C. Tusa, Jr	8,375	—	—	—	—	92,865
Warren Bonham	—	—	3,665	—	—	—
Richard DeShazo	19,674	2,919	—	—	36,855	—
Deborah Deibert	11,564	3,300	—	—	—	—

(1) Mr. Tusa's reimbursement for relocation, moving and temporary living costs includes $79,362 for selling costs associated with his residence, $12,156 for actual moving-related costs, and $1,347 for personal use of a company-leased apartment.

(5) Mr. Lane terminated employment on May 1, 2015.

(6) Mr. Tusa terminated employment on January 29, 2016.

(7) Mr. DeShazo was not a "named executive officer" of the company in 2013. Mr. DeShazo retired on November 13, 2015.

(8) Ms. Deibert was not a "named executive officer" of the company in 2013 or 2014.

Grants of Plan-Based Awards in 2014

The following table sets forth information regarding grants of plan-based awards made to our named executive officers during the year ended December 31, 2015:

		Estimated Possible Payouts under Non-Equity Incentive Plan Awards (1)			Estimated Possible Payouts under Equity Incentive Plan Awards (2)				
Name	Grant Date	Threshold ($)	Target ($)	Maximum (S)	Threshold (#)	Target (#)	Maximum (#)	All Other Stock Awards: Number of Units (#)(3)	Grant Date Fair Value of Stock Awards ($)
Rick Shearer		47,500	380,000	—	—	—	—	—	—
	7/1/15	—	—	—	6,812	13,623	13,623	—	499,964
	7/1/15	—	—	—	—	—	—	13,623	499,964
Robert Lane		27,913	139,563	—	—	—	—	—	—
	1/1/15	—	—	—	—	—	—	1,200	64,800
Joseph C. Tusa, Jr		33,500	251,250	—	—	—	—	—	—
	5/4/15	—	—	—	1,310	2,619	2,619	—	99,993
	5/4/15	—	—	—	—	—	—	2,619	99,993
Warren Bonham		36,750	84,000	—	—	—	—	—	—
Richard DeShazo		22,113	110,565	—	—	—	—	—	—
Deborah Deibert		18,620	93,099	—	—	—	—	—	—
	1/1/15	—	—	—	—	—	—	600	32,400

10/26/15	—	—	—	—	—	—	7,000	34,860

(1) Amounts shown in these columns represent each named executive officer's non-discretionary incentive bonus opportunity under our 2015 bonus programs. The "Target" amount represents the named executive officer's target bonus if the performance goal under the applicable bonus program was achieved at the target levels and the "Threshold" amount represents the named executive officer's minimum bonus if the performance goal under the incentive bonus plan was achieved at the minimum percentage level. There was no maximum funding level under the 2015 annual incentive bonus programs.

(2) Consists of performance-based vesting phantom units awards which the board of directors of our general partner approved in 2015. For details of each award, see “Elements of Executive Compensation - Equity Awards” above.

(3) Consists of time-base vesting phantom units awards which the board of directors of our general partner approved in 2015. For details of each award, see “Elements of Executive Compensation - Equity Awards” above.

Narrative Disclosure to Summary Compensation Table

Employment Letters

Our general partner is a party to employment letters with Mr. Shearer and Ms. Deibert and was a party to employment letters with Messrs. Lane, Tusa and DeShazo prior to each executive’s termination of employment, each of which is described below. We have not entered into an employment letter or employment agreement with Mr. Bonham.

Rick Shearer. Our general partner and Mr. Shearer are parties to an amended employment letter agreement (the “Amended Shearer Letter”), dated May 29, 2013, that provides for Mr. Shearer’s employment as Chief Executive Officer of our general partner. The Amended Shearer Letter amends and restates the employment letter agreement between SSS and Mr. Shearer, dated March 23, 2010 and amended May 17, 2011, which was assigned to our general partner in connection with our IPO. The Amended Shearer Letter expired on December 31, 2015, but the term of the Amended Shearer Letter is subject to automatic one-year renewals unless either our general partner or Mr. Shearer gives written notice of termination at least 60 days prior to the end of the applicable term.

Under the Amended Shearer Letter, Mr. Shearer’s initial annual base salary was $360,000, which is subject to automatic annual increases of at least four percent, and Mr. Shearer is eligible to receive an annual discretionary cash performance bonus under any general partner bonus plan or program applicable to similarly-situated employees. The Amended Shearer Letter also provides that Mr. Shearer is eligible to participate in the welfare benefit plans maintained by our general partner on the same basis as similarly-situated employees, and is entitled to annual physical examinations, paid by our general partner, in an amount up to $3,000 per year.

Robert Lane. In October 2012, we entered into an employment letter with Robert Lane pursuant to which Mr. Lane served as Chief Financial Officer of our general partner. We assigned this employment agreement to our general partner in connection with our IPO. On May 29, 2013 and again on August 8, 2014, our general partner amended the employment letter (as amended, the “Amended Lane Letter”). Under the Amended Lane Letter, Mr. Lane’s annual base salary was $275,000 and on December 31, 2014 he was granted a phantom unit award covering a number of Emerge’s units equal to $275,000 divided by the per-share closing price of a unit on August 29, 2014. Each phantom unit award was scheduled to vest in full on December 31, 2015, subject to Mr. Lane’s continued employment. For financial reporting purposes under ASC Topic 718, we considered the grant date of each of these phantom unit awards to be August 29, 2014, which was the date that the terms of award became known. Mr. Lane was also entitled to participate in the health and welfare benefit plans maintained by our general partner from time to time.

In connection with amending his employment letter, we canceled and terminated both the Distribution LTIC and the Unit Price LTIC for 2014 and 2015. However, Mr. Lane remained eligible to receive a cash payment of $146,096 under the Distribution LTIC and the Unit Price LTIC for 2013, subject to his continued employment through December 31, 2015.

Mr. Lane terminated employment on May 1, 2015. In connection with Mr. Lane’s termination, we agreed to pay $146,096 in connection with the cancellation of the LTIC arrangements described above as part of his severance arrangement.

Joseph C. Tusa, Jr. In April 2015, we entered into an employment letter with Joseph C. Tusa, Jr. pursuant to which Mr. Tusa served as Chief Financial Officer of our general partner (the “Tusa Letter”). Under the Tusa Letter, Mr. Tusa’s annual base salary was $335,000 and he was eligible to receive an annual cash bonus targeted at 75% of his base salary. On May 4, 2015, we granted Mr. Tusa two phantom unit awards each covering a number of Emerge’s units equal to $100,000 divided by the per-unit closing price on May 4, 2015. We also agreed to provide Mr. Tusa with relocation and temporary living assistance, including 50% of the selling costs incurred in connection with the actual sale of his residence, actual out-of-pocket moving costs not to exceed $90,000, and an allowance for temporary living expenses for up to six months not to exceed $2,000 per month. Mr. Tusa was also entitled to participate in the health and welfare benefit plans maintained by our general partner on the same basis as similarly-situated employees.

Mr. Tusa terminated employment on January 29, 2016.

Richard DeShazo. On May 29, 2013, we entered into an employment letter with Richard DeShazo pursuant to which Mr. DeShazo served as Chief Accounting Officer of our general partner (the "DeShazo Letter"). Under the DeShazo Letter, Mr. DeShazo's initial annual base salary was $225,000 and he was eligible to receive an annual cash bonus targeted at 45% of his base salary. Mr. DeShazo was also entitled to participate in the health and welfare benefit plans maintained by our general partner on the same basis as similarly-situated employees.

Mr. DeShazo retired on November 13, 2015. In connection with his retirement, we entered into a Retention and Transition Bonus Agreement with Mr. DeShazo, pursuant to which he received a one-time bonus of $200,000 in connection with the successful transition of his duties to his successor.

Deborah Deibert. On October 29, 2015, we entered into a promotion letter with Deborah Deibert pursuant to which Ms. Deibert began serving as Chief Accounting Officer of our general partner (the "Deibert Letter") effective November 13, 2015. Under the Deibert Letter, Ms. Deibert's initial annual salary was $225,000 and she was eligible to receive an annual cash bonus for 2015 targeted at 45% of her base salary. Ms. Deibert is also entitled to participate in the health and welfare benefit plans maintained by our general partner on the same basis as similarly-situated employees. On February 8, 2016, we amended the Deibert Letter (as amended due to her promotion to CFO, the "Amended Deibert Letter") to increase Ms. Deibert's annual salary to $280,000, to increase Ms. Deibert's target annual cash bonus to 50% of her base salary and to enhance Ms. Deibert's severance benefits.

The Amended Shearer Letter, the Amended Lane Letter, the Tusa Letter, the DeShazo Letter, and the Amended Deibert Letter also provide or provided for certain payments and benefits upon a termination of employment in certain circumstances by our general partner without "cause," and, with respect to the DeShazo Letter, by Mr. DeShazo for "good reason" (each, as defined in the applicable employment letter), as described under "Potential Payments Upon a Termination or Change of Control" below. employment letter), as described under "Potential Payments Upon a Termination or Change of Control" below.

Outstanding Equity Awards at December 31, 2015

The following table summarizes the number of shares of our common units underlying outstanding equity incentive plan awards for each named executive officer as of December 31, 2015:

Name	Grant Date	Number of Units That Have Not Vested (#)	Market Value of Units That Have Not Vested ($)(1)	Equity Incentive Plan Awards: Number of Unearned Units That Have Not Vested (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Units That Have Not Vested ($)(2)
Rick Shearer	7/1/15 (3)	13,623	63,074		
	7/1/15 (4)	—	—	13,623	63,074
Robert Lane		—	—	—	—
Joseph C. Tusa, Jr	5/4/15 (5)	2,619	12,126	—	—
	5/4/15 (6)			2,619	12,126
Warren Bonham	5/14/13 (5)			82,974	1,130,106
Richard DeShazo	—	—	—	—	—
Deborah Deibert	1/1/15 (8)	600	2,778	—	—
	10/26/15 (8)	7,000	32,410	—	—

(1) The market value of phantom units that have not vested is calculated based on the closing trading price of our common units as reported on the New York Stock Exchange on December 31, 2015 ($4.63).

(2) The payout value for Mr. Bonham includes $745,936 of outstanding DERs that were accrued as of December 31, 2015 and will be paid once the underlying phantom unit award and associated DERs vest.

(3) This phantom unit award vests, subject to continued service, in equal installments on the first, second and, third anniversaries of the vesting commencement date (July 1, 2015). In addition, this phantom unit award may be subject to accelerated vesting immediately prior to a change in control or upon a qualifying termination of service.

(4) This phantom unit award vests based on achievement of the following unit price targets, and subject to continued service: (i) 50% on the date our per-unit closing price equals or exceeds 1.25 times the per-unit closing price on the grant date ($36.70); and (ii) 50% on the date our per-unit closing price equals or exceeds 2.0 times the per-unit closing price on the grant date. In addition, this phantom unit award may be subject to accelerated vesting

immediately prior to a change in control.

(5) This phantom unit award vests, subject to continued service, in equal installments on the first, second, third and, fourth anniversaries of the vesting commencement date (May 4, 2015). In addition, this phantom unit award may be subject to accelerated vesting immediately prior to a change in control or upon a qualifying termination of service. Mr. Tusa forfeited this award in connection with his termination of employment on January 29, 2016.

(6) This phantom unit award vests based on achievement of the following unit price targets, and subject to continued service: (i) 50% vest on the date our per-unit closing price equals or exceeds 1.5 times the per-unit closing price on the grant date ($38.18); and (ii) 50% vest on the date our per-unit closing price equals or exceeds 2.0 times the per-unit closing price

on the grant date. In addition, this phantom unit award may be subject to accelerated vesting immediately prior to a change in control. Mr. Tusa forfeited this award in connection with his termination of employment on January 29, 2016.

(7) This phantom unit award vests subject to continued service, based on the achievement of performance, in pro-rated installments in connection with the sale or disposition of common units held by Insight Equity based on the ratio of common units sold or disposed of by Insight Equity as compared to the total number of common units held by Insight Equity immediately following the completion of our IPO. In addition, this phantom unit award may be subject to accelerated vesting immediately prior to a change in control. The number of units that have not vested, as shown in the table, assumes a payout of the unvested portion of the phantom unit award.

(8) These phantom unit awards vest, subject to continued service, in equal installments on the first, second, and third anniversaries of the vesting commencement date (January 1, 2015 or October 1, 2015, as applicable). In addition, these phantom unit awards may be subject to accelerated vesting immediately prior to a change in control.

Option Exercises and Stock Vested

The following table provides information regarding the value realized by each of the named executive officers as a result of phantom units that vested during fiscal year 2015:

Name	Number of Units Acquired on Vesting (#)	Value Realized on Vesting ($)(1)
Rick Shearer	265,294	10,256,266
Robert Lane	—	—
Joseph C. Tusa, Jr	—	—
Warren Bonham	—	—
Richard DeShazo	—	—
Deborah Deibert	—	—

(1) Represents the product of the number of phantom units which vested and the closing price of our common units on the vesting date. Mr. Shearer’s phantom units are accompanied by tandem DERs, which were vested as of the date of grant (May 14, 2013). The value includes $639,359 distributed in 2015 to Mr. Shearer related to his DERs.

Potential Payments Upon a Termination or Change of Control

Employment Letters

Rick Shearer. The Amended Shearer Letter provides that if Mr. Shearer’s employment is terminated by our general partner without “cause” (as defined in the Amended Shearer Letter) during (a) the first thirty-six months after his hire date or (b) during any subsequent one-year extension (which occurs automatically unless either party provides notice at least 30 days prior to the end of the initial three-year period or subsequent one-year extension), Mr. Shearer will be entitled to receive an amount equal to twice his then-current annual base salary, payable in a cash lump sum amount within sixty days after the termination date.

Robert Lane. The Amended Lane Letter provided that if Mr. Lane’s employment was terminated by the company without “cause” (as defined in the Amended Lane Letter), then Mr. Lane would be entitled to receive (a) an amount equal to his annual base salary (or, if such termination occurs within two months following a “change in control” (as defined in the Amended Lane Letter), an amount equal to 27 months of his annual base salary) and (b) immediate vesting in, and payment of, the Distribution LTIC and Unit Price LTIC to the extent each had been earned as of the termination date. Each of the payments described in this paragraph would be paid in a cash lump sum amount on the 60th day following Mr. Lane’s termination date, subject to his timely execution and non-revocation of a release of claims.

Joseph C. Tusa, Jr. The Tusa Letter provided that if Mr. Tusa’s employment was terminated by our general partner without “cause,” then Mr. Tusa would be entitled to receive (a) an amount equal to his annual base salary and (b) partial accelerated vesting of the time-vesting phantom unit award granted to him in connection with his hiring in May 2015.

Warren Bonham. Except with respect to his phantom unit awards (described below), Mr. Bonham is not eligible to receive any severance or change in control benefits.

Richard DeShazo. The DeShazo Letter provided that if Mr. DeShazo’s employment was terminated by our general partner without “cause” or Mr. DeShazo terminated his employment for “good reason,” in each case, within six months following a “change of control” (each, as defined in the DeShazo Letter), then Mr. DeShazo would be entitled to receive (a) an amount equal to his annual base salary, and (b) an amount equal to his target bonus, pro-rated to reflect the partial year of service, in each case payable in a cash lump sum amount on the 60th day following Mr. DeShazo’s termination date, subject to his timely execution and non-revocation of a release of claims.

Deborah Deibert. The Deibert Letter provides that if Ms. Deibert's employment is terminated by our general partner without "cause" (as defined in the Deibert Letter), then Ms. Deibert will be entitled to receive an amount equal to six months of her then current annual base salary payable in a cash lump sum amount on the 60th day following Ms. Deibert's termination date, subject to his timely execution and non-revocation of a release of claims. The Amended Deibert Letter, which became effective on February 8, 2016, enhanced Ms. Deibert's severance benefits such that Ms. Deibert would be entitled to receive an amount equal to nine months of her then current annual base salary.

Phantom Unit Awards

Time-vesting phantom unit awards held (or previously held, as applicable) by Messrs. Shearer and Tusa will accelerate and vest in full immediately prior to a change in control. In addition, Messrs. Shearer's and Tusa's time-vesting phantom unit awards provide for partial accelerated vesting upon a termination of service without "cause" (as defined in the applicable award agreement).

Performance-vesting phantom unit awards held (or previously held, as applicable) by Messrs. Shearer and Tusa and time-vesting phantom unit awards held (or previously held, as applicable) by Messrs. Lane, Bonham and DeShazo and Ms. Deibert, in either case, will accelerate and vest in full immediately prior to a change in control.

Summary of Potential Payments

The following table summarizes the payments that would be made to our named executive officers upon the occurrence of certain qualifying terminations of employment or a change in control event, assuming such named executive officer's termination of employment occurred on December 31, 2015 and, where relevant, that a change in control occurred on December 31, 2015. Amounts shown in the table below do not include (1) accrued but unpaid salary and (2) other benefits earned or accrued by the named executive officer during his employment that are available to all salaried employees, such as accrued vacation.

The amounts disclosed below for Messrs. Lane and DeShazo reflect amounts actually paid in connection with the executive's termination of employment in 2015.

Name	Termination Due to Death or Disability ($)	Change in Control (No Termination) ($)	Qualifying Termination (Not in Connection with Change of Control) ($)	Qualifying Termination (In Connection with Change of Control) ($)
Rick Shearer				
Cash Severance	—	—	1,000,000	1,000,000
Bonus Severance	—	—	—	—
Phantom Unit Acceleration	—	126,148	10,599	126,148
Total	—	126,148	1,010,599	1,126,148
Robert Lane				
Cash Severance	—	—	252,758	—
Bonus Severance	—	—	146,096	—
Phantom Unit Acceleration	—	—	—	—
Total	—	—	398,854	—
Joseph C. Tusa, Jr (2)				
Cash Severance	—	—	335,000	335,000
Bonus Severance	—	—	—	—
Phantom Unit Acceleration	—	24,252	2,002	24,252
Total	—	24,252	337,002	359,252
Warren Bonham	—	—	—	
Cash Severance	—	—	—	—
Bonus Severance	—	—	—	—
Phantom Unit Acceleration	—	1,130,106	—	1,130,106
Total	—	1,130,106	—	1,130,106
Richard DeShazo				
Cash Severance	—	—	—	—
Bonus Severance	—	—	200,000	—
Phantom Unit Acceleration	—	—	—	—
Total	—	—	200,000	—
Deborah Deibert				
Cash Severance	—	—	112,500	112,500
Bonus Severance	—	—	—	—
Phantom Unit Acceleration	—	35,188	—	35,188
Total	—	35,188	112,500	147,688

Director Compensation

On May 14, 2013, the board of directors of our general partner adopted, and in January 2015, it amended, the Emerge Energy Services LP Director Compensation Program (the “Director Plan”). Any non-employee director not affiliated with the partnership, our general partner, or certain Insight Equity affiliates is eligible to receive awards under the Director Plan.

Cash Compensation

Under the Director Plan, each eligible director is entitled to receive an annual cash retainer of $50,000. In addition, each committee chairperson receives a $10,000 annual cash retainer and each non-chair committee member receives a $2,500 annual cash retainer. Annual retainers are paid in cash quarterly in arrears, and are pro-rated to reflect any partial year of service.

Equity Compensation

Under the Director Plan, any eligible director who joins the board of directors of our general partner will receive a grant of restricted units covering a number of units having a value equal to $75,000 when he or she joins the board of directors of our general partner, pro-rated to reflect any partial year of service. Each restricted unit grant will vest in full on the anniversary of the closing of our IPO (May 14, 2013) immediately following the applicable grant date, subject to the eligible director's continued service through the applicable vesting date. An eligible director serving on the board of directors of our general partner as of an anniversary of the closing of our IPO will be granted a restricted unit award valued at $75,000 on the applicable anniversary date, which will vest in full on the first anniversary of the grant date subject to continued service through the applicable vesting date.

2015 Director Compensation Table

Name (1)	Fees Earned in Cash ($)(2)	Stock Awards ($)(3)	Total ($)
Kevin Clark	62,500	74,973	137,473
Mark Gottfredson (4)	26,250	87,509	113,759
Peter Jones (5)	51,250	74,973	126,223
Francis J. Kelly, III	62,500	74,973	137,473
Kevin McCarthy (6)	37,500	74,973 (7)	37,500

(1) Only non-employee directors who are not affiliated with us, our general partner, or certain Insight Equity affiliates are eligible to receive cash and/or equity compensation pursuant to the Director Plan.

(2) The amounts shown in this column include the annual retainer and any individual retainers for serving as the chair or non-chair committee member, in each case earned in 2015.

(3) The amounts shown in this column reflect the aggregate grant date fair value of restricted units awards granted in 2015, calculated in accordance with financial accounting standards. For a discussion of the assumptions used to calculate the value of all restricted unit awards made to directors, refer to Note 11 to our financial statements included in this Annual Report on Form 10-K for the period ended December 31, 2015. The total number of restricted units outstanding as of the end of the 2015 fiscal year for each non-employee director was 2,049.

(4) Mr. Gottfredson was appointed as an independent director of our general partner and as a member of the Audit Committee on March 25, 2015. In connection with his appointment, Mr. Gottfredson received a restricted unit award of 242 units for the period covering his date of appointment through the anniversary date of our IPO (May 14, 2015).

(5) Mr. Jones resigned his Audit Committee membership on March 20, 2015.

(6) Mr. McCarthy resigned from the board of directors of our general partner on July 27, 2015.

(7) In connection with his resignation from the board of directors of our general partner, Mr. McCarthy forfeited his restricted stock unit award granted in 2015.

Compensation Committee Report

As our general partner does not have a compensation committee, the board of directors of our general partner provides the oversight, administers, and makes decisions regarding our compensation policies and plans. Additionally, the board of directors of our general partner generally reviews and discusses the Compensation Discussion and Analysis with senior management of our general partner as a part of our governance practices. Based on this review and discussion, the board of directors of our general partner has directed that the Compensation Discussion and Analysis be included in this report for filing with the SEC.

Members of the Board of Directors of Emerge Energy Services GP LLC

Ted W. Beneski	Warren B. Bonham	Kevin Clark
Mark Gottfredson	Peter Jones	Francis J. Kelly, III
Eliot Kerlin	Rick Shearer	Victor L. Vescovo

Compensation Committee Interlocks and Insider Participation

As previously discussed, the board of directors of our general partner is not required to maintain, and does not maintain a compensation committee.

Messrs. Shearer and Bonham, who serve on the board of directors of our general partner, participate in their capacities as directors in the deliberations of the board of directors of our general partner concerning executive officer compensation. In addition, Mr. Shearer makes recommendations to the board of directors of our general partner regarding named executive officer compensation. Each of Messrs. Shearer and Bonham abstain from any decision regarding his own compensation.

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ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED UNITHOLDER MATTERS

The following table sets forth certain information regarding the beneficial ownership of units as of February 23, 2016 (the “Ownership Reference Date”) by:

- each person who is known to us to beneficially own 5% or more of such units to be outstanding;
- our general partner;
- each of the directors and named executive officers of our general partner; and
- all of the directors and executive officers of our general partner as a group.

All information with respect to beneficial ownership has been furnished by the respective directors, officers or 5% or more unitholders as the case may be.

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 the Ownership Reference Date, 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.

The percentage of units beneficially owned is based on a total 24,121,222 common units outstanding as of the Ownership Reference Date. Except as indicated by footnote, the persons named in the table below have sole voting and investment power with respect to all units shown as beneficially owned by them and their address is 180 State Street, Suite 225, Southlake, Texas 76092.

Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units to be Beneficially Owned
Insight Equity (1)	7,168,545	30.2%
Ted W. Beneski (2)	1,172,624	4.9%
Rick Shearer	251,644	*
Victor L. Vescovo	139,752	*
Warren B. Bonham	6,899	*
Joseph C. Tusa, Jr.	—	*
Deborah Deibert	134	*
Mark Gottfredson (5)	10,242	*
Francis J. Kelly III (5)	4,236	*
Kevin Clark (5)	2,974	*
Eliot E. Kerlin, Jr.	2,408	*
Peter Jones (5)	774	*
All directors and officers as a group (11 persons)	8,760,232	36.3%

An asterisk indicates that the person or entity owns less than one percent.

(1) As described elsewhere in this prospectus, Ted W. Beneski and Victor L. Vescovo are the controlling equity owners of Insight Equity, which owns a controlling interest in Emerge Holdings, the entity which owns Emerge Energy Services GP, LLC. Messrs. Beneski and Vescovo, by virtue of being controlling equity owners of Insight Equity, may be deemed to beneficially own the units held by Insight Equity. Messrs. Beneski and Vescovo disclaim beneficial ownership of the units held by Insight Equity except to the extent of their pecuniary interest therein.

(2) Amounts do not include 27,522 units for which Mr. Beneski disclaims beneficial ownership, which are held in irrevocable trust accounts in favor of his sons. Mr. Beneski is the trustee of each trust account.

Securities Authorized for Issuance under Equity Compensation Plans

The following table summarizes certain information regarding our equity compensation plans, including our LTIP, as of December 31, 2015. Our LTIP allows for awards of options, phantom units, restricted units, unit awards, other unit awards and unit appreciation rights.

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 (Excluding Securities Reflected in Column(a))
	(a)(1)	(b)	(c)(2)
Equity compensation plans approved by security holders	225,000	$—	1,196,676
Equity compensation plans not approved by security holders	—	—	—
Total	225,000	$—	1,196,676

(1) The amounts in column (a) of this table reflect only phantom units that have been granted (but not yet issued) under the LTIP. No unit options have been granted. Our LTIP was approved by our partners (general and limited) prior to our IPO. No value is shown in column (b) of the table, since the phantom units do not have an exercise, or strike, price.

(2) The LTIP was adopted by the Emerge Energy Services GP LLC Board of Directors in connection with the closing of our IPO in May 2013, and provides for awards of options, restricted units, phantom units, distribution equivalent rights, substitute awards, unit appreciation rights, unit awards, profits interest units and other unit-based awards to be available for employees, consultants and directors of our general partner and any affiliates who perform services for Emerge Energy Services LP.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Ownership Interests of Certain Executive Officers and Directors of Our General Partner

Insight Equity owns 7,168,545 common units representing a 30.2% limited partner interest in us, and is controlled by Ted Beneski and Victor Vescovo, the Chairman of the Board and each a member of our board of directors. Emerge Energy Services Holdings LLC is the sole member of our general partner. Emerge Energy Services Holdings LLC is controlled by Insight Equity.

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 affiliates in connection with our ongoing operation and liquidation. These distributions and payments were determined by and among affiliated entities and, consequently, are not the result of arm's-length negotiations.

Post-IPO Stage

Distributions of available cash to our general partner and its affiliates	We make cash distributions pro rata to the holders of our common units, including affiliates of our general partner, as the holders of an aggregate of 7,168,545 common units.
Payments to our general partner and its affiliates	Our general partner does not receive a management fee or other compensation for its management of us. Our general partner and its affiliates are reimbursed for expenses incurred on our behalf. Our partnership agreement provides that our general partner determines the amount of these expenses.
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 particular capital account balances.

Other Agreements with Affiliates

We have various agreements with certain of our affiliates, as described below. These agreements have been negotiated among affiliated parties and, consequently, are not the result of arm's-length negotiations.

We entered into an administrative services agreement with Insight Management Company LLC pursuant to which Insight Management Company LLC provides specified general and administrative services to us and our subsidiaries from time to time. Under the terms of the agreement, we reimburse Insight Management Company LLC based on agreed upon-formulas on a monthly basis for the time and materials actually spent in performing general and administrative services on our behalf. In addition, Warren B. Bonham is considered to be an employee of Insight Management Company LLC and also serves as the head of our Fuel segment. Mr. Bonham’s compensation for services provided to us are included in our normal periodic charges from our general partner for all of our employee costs. We expect that this administrative services agreement will remain in force until (i) the date we and Insight Management Company LLC mutually agree to terminate it; (ii) the final distribution in liquidation of us or our subsidiaries; or (iii) the date on which neither Insight Equity nor any of its affiliates own equity securities of us. We believe that the terms of the administrative services agreement are no less favorable to us than those generally available from unrelated third parties.

Procedures for Review, Approval and Ratification of Related-Person Transactions

Our code of business conduct and ethics provides that the board of directors of our general partner or its authorized committee periodically review all related person transactions that are required to be disclosed under SEC rules and, when appropriate, initially authorize or ratify all such transactions. 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 provides that our management will make all reasonable efforts to cancel or annul the transaction.

The code of business conduct and ethics provides that, in determining whether or not to recommend the initial approval or ratification of a related person transaction, the board of directors of our general partner or its authorized committee should consider all of the relevant facts and circumstances available, including (if applicable) but not limited to: (i) whether there is an appropriate business justification for the transaction; (ii) the benefits that accrue to us as a result of the transaction; (iii) the terms available to unrelated third parties entering into similar transactions;

(iv) the impact of the transaction on a director's independence (in the event the related person is a director, an immediate family member of a director or an entity in which a director or an immediately family member of a director is a partner, shareholder, member or executive officer); (v) the availability of other sources for comparable products or services; (vi) whether it is a single transaction or a series of ongoing, related transactions; and (vii) whether entering into the transaction would be consistent with the code of business conduct and ethics.

Further information required for this item is provided in Part I, Item 1. Business—Overview, Part III, Item 10. Directors, Executive Officers and Corporate Governance and Note 11, Related Party Transactions, included in the notes to the audited consolidated financial statements included in Part II, Item 8. Financial Statements and Supplementary Data.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

We have engaged BDO USA, LLP ("BDO") as our independent registered public accounting firm. The following table sets forth fees billed for professional serviced rendered by BDO to audit our annual financial statements and for other services in 2015 and 2014, including out-of-pocket expenses billed.

	Year Ended December 31,	
	2015	2014
	($ in thousands)	
Audit fees (1)	$1,775	$1,825
Audit-related fees (2)	—	68
Tax fees (3)	4	4
Total	$1,779	$1,897

(1) Consists primarily of services provided in connection with the audit of the annual financial statements, audit of internal control over financial reporting, review of quarterly financial statements, services related to offering documents and advice on accounting policies.

(2) Consists primarily of services performed related to business combination, S-3 Filing review and SOX 404 (a) consulting.

(3) Represents fees for professional services in connection with tax compliance and planning.

Pursuant to the charter of the Audit Committee, the Audit Committee is responsible for the oversight of our accounting, reporting and financial practices. The Audit Committee is responsible for the appointment, compensation, retention and oversight of the work of our external auditors; the pre-approval of all audit and non-audit services to be provided, consistent with all applicable laws, to us by our external auditors; and the establishment of the fees and other compensation to be paid to our external auditors. The Audit Committee also oversees and directs our internal auditing program and reviews our internal controls.

The Audit Committee has adopted a policy for the pre-approval of audit and permitted non-audit services provided by our principal independent accountants. The policy requires that all services provided by BDO, including audit services, audit-related services, tax services and other services, must be pre-approved by the Audit Committee.

The Audit Committee reviews the external auditors' proposed scope and approach as well as the performance of the external auditors. It also has direct responsibility for resolution of and sole authority to resolve any disagreements between our management and our external auditors regarding financial reporting, regularly reviews with the external auditors any problems or difficulties the auditors encounter in the course of their audit work, and, at least annually, uses its reasonable efforts to obtain and review a report from the external auditors addressing the following (among other items):

- the external auditors' internal quality-control procedures;
- any material issues raised by the most recent internal quality-control review, or peer review, of the external auditors;
- the independence of the external auditors;
- the aggregate fees billed by the external auditors for each of the previous two fiscal years; and
- the rotation of the external auditors' lead partner.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a)(1). Financial Statements. See "Index to Financial Statements" on page 69.

(a)(2). Financial Statement Schedules. Other schedules are omitted because they are not required or applicable, or the required information is included in our consolidated financial statements or related notes.

(a)(3). Exhibits. See "Index to Exhibits."

Schedules other than those listed above are omitted because they are not required, not material, not applicable or the required information is shown in the financial statements or notes thereto.

Agreements attached or incorporated herein as exhibits to this report are included to provide investors with information regarding the terms and conditions of such agreements and are not intended to provide any other factual or disclosure information about Emerge Energy Services LP or the other parties to the agreements.

Such agreements may contain representations and warranties by the parties to the applicable agreement. These representations and warranties have been made solely for the benefit of the other parties to the applicable agreement and (i) should not in all instances be treated as categorical statements of fact, but rather as a way of allocating the risk to one of the parties if those statements prove to be inaccurate, (ii) have been qualified by disclosures that were made to the other party or parties in connection with the negotiation of the applicable agreement, which disclosures are not necessarily reflected in the agreement, (iii) may apply standards of materiality in a way that is different from what may be viewed as material to you or other investors and (iv) were made only as of the date of the applicable agreement or such other date or dates as may be specified in the agreement and are subject to more recent developments. Accordingly, the representations and warranties in such agreements may not describe the actual state of affairs as of the date they were made or at any other time.

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.

Date: February 29, 2016

EMERGE ENERGY SERVICES LP

By: EMERGE ENERGY SERVICES GP LLC,
its general partner

By: /s/ Rick Shearer
Rick Shearer
President, Chief Executive Officer and Director
(Principal Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons in their indicated capacities, which are with the general partner of the registrant, on the dates indicated.

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Signature	Title	Date
/s/ Rick Shearer Rick Shearer	President, Chief Executive Officer and Director (principal executive officer)	February 29, 2016
/s/ Deborah Deibert Deborah Deibert	Chief Financial Officer (principal financial officer)	February 29, 2016
/s/ Nadya Kurani Nadya Kurani	Chief Accounting Officer (principal accounting officer)	February 29, 2016
/s/ Ted W. Beneski Ted W. Beneski	Chairman of the Board and Director	February 29, 2016
/s/ Warren B. Bonham Warren B. Bonham	Director	February 29, 2016
/s/ Kevin Clark Kevin Clark	Director	February 29, 2016
/s/ Mark Gottfredson Mark Gottfredson	Director	February 29, 2016
/s/ Peter Jones Peter Jones	Director	February 29, 2016
/s/ Francis Kelly Francis Kelly	Director	February 29, 2016
/s/ Eliot Kerlin Eliot Kerlin	Director	February 29, 2016
/s/ Victor L. Vescovo Victor L. Vescovo	Director	February 29, 2016

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INDEX TO EXHIBITS

Exhibit Number	Description
3.1	Certificate of Limited Partnership of Emerge Energy Services LP (incorporated by reference to Exhibit 3.1 to the Registrant’s Registration Statement on Form S-1, Registration No. 333-187487).
3.2	Amendment to Certificate of Limited Partnership of Emerge Energy Services LP (incorporated by reference to Exhibit 3.2 to the Registrant’s Registration Statement on Form S-1, Registration No. 333-187487).
3.3	First Amended and Restated Limited Partnership Agreement of Emerge Energy Services LP, dated as of May 14, 2013 (incorporated by reference to Exhibit 3.1 to the Registrant’s Current Report on Form 8-K, filed with the SEC on May 20, 2013).
3.4	Certificate of Limited Formation of Emerge Energy Services GP LLC (incorporated by reference to Exhibit 3.5 to the Registrant’s Registration Statement on Form S-1, Registration No. 333-187487).
3.5	Amendment to Certificate of Formation of Emerge Energy Services GP LLC (incorporated by reference to Exhibit 3.6 to the Registrant’s Registration Statement on Form S-1, Registration No. 333-187487).
3.6	Amended and Restated Limited Liability Company Agreement of Emerge Energy Services GP, LLC, dated as of May 14, 2013 (incorporated by reference to Exhibit 3.2 to the Registrant’s Current Report on Form 8-K, filed with the SEC on May 20, 2013).
4.1	Registration Rights Agreement, dated as of May 14, 2013, by and among Emerge Energy Services LP, AEC Resources LLC, Ted W. Beneski, Superior Silica Resources LLC, Kayne Anderson Development Company and LBC Sub V, LLC (incorporated by reference to Exhibit 10.5 to the Registrant's Current Report on Form 8-K, filed with the SEC on May 20, 2013).
10.1	Amended and Restated Revolving Credit and Security Agreement, dated as of June 27, 2014, among Emerge Energy Services LP, as parent guarantor, the Borrowers party thereto, PNC Bank, National Association, as administrative agent and collateral agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to the Registrant’s Current Report on Form 8-K, filed with the SEC on June 30, 2014).
10.2	Administrative Services Agreement, dated as of May 14, 2013, by and among Emerge Energy Services LP, Emerge Energy Services GP LLC and Insight Equity Management Company LLC (incorporated by reference to Exhibit 10.6 to the Registrant's Current Report on Form 8-K, filed with the SEC on May 20, 2013).
10.3#	Emerge Energy Services LP 2013 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.3 to the Registrant's Current Report on Form 8-K, filed with the SEC on May 20, 2013).
10.4#	Emerge Energy Services LP Director Compensation Program (incorporated by reference to Exhibit 10.4 to the Registrant’s Annual report on Form 10-K, filed with the SEC on March 5, 2015).
10.5#	

	Form of Emerge Energy Services LP 2013 Long-Term Incentive Plan Phantom Unit Agreement (Performance-Vesting Agreement) (incorporated by reference to Exhibit 10.7 to the Registrant's Current Report on Form 8-K, filed with the SEC on May 20, 2013).
10.6#	Form of Emerge Energy Services LP 2013 Long-Term Incentive Plan Phantom Unit Agreement (Time-Vesting Agreement) (incorporated by reference to Exhibit 10.8 to the Registrant's Current Report on Form 8-K, filed with the SEC on May 20, 2013).
10.7#	Amended Employment Letter, dated May 29, 2013, between Emerge Energy Services GP LLC and Rick Shearer (incorporated by reference to Exhibit 10.3 to the Registrant's Current Report on Form 8-K, filed with the SEC on June 4, 2013).
10.8#	Letter Agreement, dated May 29, 2013, between Emerge Energy Services GP LLC and Rick Shearer (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K, filed with the SEC on June 4, 2013).
10.9#	Second Amendment to Employment Letter, dated August 5, 2014, between Emerge Energy Services GP LLC and Robert Lane (incorporated by reference to Exhibit 10.1 to the Registrant’s Current Report on Form 8-K, filed with the SEC on August 11, 2014).
10.10 †	Sand Supply Agreement, dated as of May 31, 2011, between Superior Silica Sands LLC and Schlumberger Technology Corporation (incorporated by reference to Exhibit 10.5 to the Registrant's Registration Statement on Form S-1, Registration No. 333-187487).

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Exhibit Number	Description
10.11 †	Sand Supply Agreement, dated as of March 31, 2011, between Superior Silica Sands LLC and BJ Services Company, U.S.A (incorporated by reference to Exhibit 10.6 to the Registrant's Registration Statement on Form S-1, Registration No. 333-187487).
10.12 †	Amendment to Sand Supply Agreement, dated as of November 15, 2012 between Superior Silica Sands LLC and Schlumberger Technology Corporation (incorporated by reference to Exhibit 10.11 to the Registrant's Registration Statement on Form S-1, Registration No. 333-187487).
10.13 †	Second Amendment to Sand Supply Agreement, dated as of June 10, 2014, between Superior Silica Sands LLC and Schlumberger Technology Corporation (incorporated by reference to Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q, filed with the SEC on November 7, 2014).
10.14 †	Memorandum of Understanding, dated May 9, 2012, between Canadian National Railway Company and Superior Silica Sands LLC (incorporated by reference to Exhibit 10.9 to the Registrant's Registration Statement on Form S-1, Registration No. 333-187487).
10.15 †	Wet Sand Services Agreement, dated April 7, 2011, by and between Superior Silica Sands LLC and Fred Weber, Inc. (incorporated by reference to Exhibit 10.10 to the Registrant's Registration Statement on Form S-1, Registration No. 333-187487).
10.16	Contribution, Conveyance and Assumption Agreement, dated as of May 14, 2013, by and among Emerge Energy Services GP LLC, Emerge Energy Services LP, Emerge Energy Services Operating LLC, Emerge Energy Services Holdings LLC, and the other parties thereto (incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K, filed with the SEC on May 20, 2013).
10.17#	Employment Letter, dated April 13, 2015, between Emerge Energy Services GP LLC and Jody Tusa (incorporated by reference to Exhibit 10.1 to the Registrant’s Current Report on Form 8-K, filed with the SEC on May 4, 2015).
10.18#	Retention and Transition Bonus Agreement, dated October 16, 2015, between Emerge Energy Services GP LLC and Richard L. DeShazo (incorporated by reference to Exhibit 10.1 to the Registrant’s Current Report on Form 8-K, filed with the SEC on October 22, 2015).
10.19#	Employment Letter, dated October 19, 2015, between Emerge Energy Services GP LLC and Deborah Deibert (incorporated by reference to Exhibit 10.2 to the Registrant’s Current Report on Form 8-K, filed with the SEC on October 22, 2015).
10.20	First Amendment to Amended and Restated Revolving Credit and Security Agreement, dated as of April 6, 2015, among Emerge Energy Services LP, as parent guarantor, the Borrowers party thereto, PNC Bank, National Association, as administrative agent and collateral agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to the Registrant’s Current Report on Form 8-K, filed with the SEC on April 8, 2015).
10.21	Limited Waiver No. 1 to Amended and Restated Revolving Credit and Security Agreement, dated as of October 19, 2015, by and among Emerge Energy Services LP, as parent guarantor, the Borrowers party thereto, the Lenders party thereto and PNC Bank, National Association, as agent for the Lenders (incorporated by reference to Exhibit 10.1 to the Registrant’s Current Report on Form 8-K, filed with

	the SEC on October 22, 2015).
10.22	Limited Waiver No. 2 to Amended and Restated Revolving Credit and Security Agreement, dated as of November 12, 2015, by and among Emerge Energy Services LP, as parent guarantor, the Borrowers party thereto, the Lenders party thereto and PNC Bank, National Association, as agent for the Lenders (incorporated by reference to Exhibit 10.1 to the Registrant’s Current Report on Form 8-K, filed with the SEC on November 16, 2015).
10.23	Amendment No. 2 to Amended and Restated Revolving Credit and Security Agreement, dated November 18, 2015, among Emerge Energy Services LP, as parent guarantor, the Borrowers party thereto, PNC Bank, National Association, as administrative agent and collateral agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q, filed with the SEC on November 20, 2015).
10.24*†	Amended and Restated Master Supply Agreement, dated December 22, 2015, between Superior Silica Sands LLC and Performance Technologies, LLC.
10.25*†	Purchase Option Agreement, dated December 22, 2015, between Superior Silica Sands LLC and Performance Technologies, LLC.
21.1*	List of Subsidiaries of Emerge Energy Services LP.

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Exhibit Number	Description
23.1*	Consent of BDO USA, LLP.
23.2*	Consent of Cooper Engineering Company, Inc.
23.3*	Consent of Westward Environmental, Inc.
31.1*	Certification of Chief Executive Officer under Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer under Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Chief Executive Officer under Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of Chief Financial Officer under Section 906 of the Sarbanes-Oxley Act of 2002.
95.1*	Mine Safety Disclosure Exhibit.
101*	Interactive Data Files - XBRL.

* Filed herewith (or furnished in the case of Exhibits 32.1 and 32.2).
\# Compensatory plan or arrangement.
† Certain portions have been omitted pursuant to a confidential treatment request. Omitted information has been separately filed with the Securities and Exchange Commission.