Emerge Energy Services LP
Form 10-K
March 02, 2015
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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, 2014

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. ý Yes o 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, 2014, the last business day of the registrant's second fiscal quarter of 2014, the aggregate market value of the registrant's common units held by non-affiliates of the registrant was $1,644,038,050 based on the closing price as reported on the New York Stock Exchange composite tape on that date.

As of February 23, 2015, 23,718,961 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.

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.

ppm: Parts per million.

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Proppant: A sized particle mixed with fracturing fluid to hold fractures open after a hydraulic fracturing treatment.
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.

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 business results and total distributions. We focus on optimizing our business results and maximizing total distributions. The board of directors of our general partner adopted a policy under which distributions for each quarter are equal to the amount of available cash we generate each quarter. In addition, our general partner has a non-economic general partner interest and no incentive distribution rights, and, accordingly, all of our unitholders, including our sponsor, receive 100% of our cash distributions on a pro rata basis.
- Seek contractual cash flow stability. In our Sand segment, we intend to continue securing 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. Currently, 100% of our permitted production capacity at our four operating dry plant facilities is covered by long-term contracts, and 77% of our sales in the year ended December 31, 2014 were to customers currently under contract. As of December 31, 2014, we had 6.9 million tons under long-term contract with a weighted average remaining term of four years at our existing facilities, and an additional 1.5 million tons under contract that are committed to future facilities. In our Fuel segment, our contract structure is designed to capture a

stable margin, as the price differential between the refined products indices at which we purchase transmix and wholesale fuel and the sales price of the refined products fluctuates in a narrow range. In addition, we typically resell our refined products within 7 to 10 days after acquiring our transmix, wholesale fuel and other feedstock supply, which reduces our exposure to fluctuations in the

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underlying indices. We also seek to lease additional space in our terminal tanks to refiners and large fuel wholesalers, where we can capture both fixed monthly margins and fixed per-gallon throughput margins that are independent of the underlying commodity price. In addition, we enter into financial hedging arrangements to partially mitigate our direct exposure to commodity price and market index fluctuations.

- Capitalize on compelling industry fundamentals. We believe the frac sand market offers attractive long-term growth fundamentals, and we expect to continue to position ourselves as a producer of coarse, high-quality “Northern White” frac sand located in Wisconsin's Jordan, St. Peter, Mt. Simon and Wonewoc formations. Over the past several years, the demand for frac sand in the United States and Canada has grown significantly, primarily as a result of increased horizontal drilling, technological advances that allowed for the development of many unconventional resource formations, increased proppant use per well and cost advantages over other proppants such as resin coated sand and ceramic alternatives. In particular, the demand for coarse Northern White sand, such as the type we mine and sell from our Wisconsin facilities, is very strong among end users who are focused on the extraction of oil and liquids-rich natural gas. We believe frac sand supply will continue to be constrained by a variety of factors, including but not limited to: (i) the difficulty in finding reserves suitable for use as frac sand, which are largely limited to select areas of the United States and which must meet the technical specifications of the American Petroleum Institute (“API”); (ii) challenges associated with locating contiguous reserves of frac sand sufficient to justify the capital investment required to develop a mine and processing plant; (iii) securing necessary local, state and federal permits required for operations; and (iv) the ability of producers to provide comprehensive logistics and delivery solutions for customers. We further believe that as customers continue to refine their approach to the frac sand market, they will continue to gravitate toward the leading producers of frac sand, including Emerge Energy, which should give us the opportunity to strengthen our market position.
- Capitalize on organic growth opportunities and optimize existing assets. We intend to focus on organic growth opportunities 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 operating at or near capacity, while our facility in Kosse, Texas is running at well over half capacity. We are also constructing a fifth production complex in Wisconsin from which we expect to begin selling sand in the second half of 2015. In addition, we continue to work on other greenfield expansion opportunities. 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 planning to build hydrotreaters at our two fuel terminals to allow us to process low sulfur transmix into ultra-low sulfur diesel.
- Access new and adjacent markets using existing capabilities. We are exploring and will continue to explore opportunities to expand our businesses into new markets by leveraging our existing operations and our historical experiences. In our Sand segment, we will continue to pursue opportunities created by the demand for our reserves and to use available surplus processing and storage capacity in order to meet the needs of our customers. We also developed a total supply chain solution for our customers, designed to deliver sand anywhere from the railcar at the plant to within 60 miles of the wellhead. We believe this supply chain solution provides our customers with a streamlined order process that yields a lower total delivered product cost while generating incremental earnings for us and enabling us to reach a broader set of customers. For example, given our multiple railroad, trucking and barging logistics capabilities, we have started to explore potential sales opportunities in Central and South American countries. We have also partnered with dedicated logistics partners in Mexico in anticipation of that market opening up to Northern White frac sand over the next several years. If such opportunities materialize, we would expect to select our customers in those countries by employing the same disciplined financial criteria that we have used with respect to our existing customers. In our Fuel segment, we built the capability to blend additives into our refined products, which allows us to handle branded petroleum products in addition to unbranded products, and which we believe was critical to allow us to source new terminaling customers in the past two years. We also intend to leverage our existing customer relationships to expand our footprint in Dallas-Fort Worth and Birmingham and their adjacent markets.
- Grow business through strategic and accretive business or asset acquisitions. 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. For example, in 2014 we acquired a mine and wet plant from a supplier that have both significantly decreased our operating costs and allowed us to take market share from our competition. We have identified several highly attractive frac sand deposits and developments in properties adjacent to or in close proximity to our existing Wisconsin operations, allowing for the opportunity to contract additional reserves and additional finished product capacity. We also believe that we can replicate our transmix, wholesale and terminal business activities successfully in other regions of the United States.

- Maintain financial strength and flexibility. We intend to maintain financial strength and flexibility to enable us to pursue our growth strategy, including acquisitions, organic growth and asset optimization opportunities as they arise. As of

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December 31, 2014, we had $6.9 million of cash on hand and $120.4 million of additional liquidity available under our revolving credit facility. We plan to spend $110 million of capital expenditures in 2015, which we intend to fund with our existing credit facilities and cash from operations, including utilizing an unexercised $150 million accordion under our revolving credit facility.

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 105.5 million tons of proven recoverable sand reserves and our facility in Texas is supported by approximately 27.8 million tons of proven recoverable sand reserves. We believe that our Wisconsin reserves provide us access to a disproportionate amount of coarse sand (16/30, 20/40 and 30/50 mesh sands) compared to other Northern White deposits located in Wisconsin's Jordan, Mt. Simon, St. Peter and Wonewoc formations. 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. 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, of which we believe we are the market's largest supplier. Our access to coarse sand provides us with lower processing costs relative to mines with finer sand reserves and enables us to better serve the current levels of high demand for coarse frac sand that is related to increased hydraulic fracturing activities focused on the recovery of oil and liquids-rich gas in the United States.

Our transmix facilities are centrally located in the Dallas-Fort Worth and Birmingham metropolitan areas. The population in these areas is forecasted to increase at a weighted growth rate greater than the national average between 2010 and 2030, which is expected to drive incremental demand for the products and services we offer through our Fuel segment. 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 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.

- Stable cash flows. In our Sand segment, we currently sell our products primarily under long-term supply agreements under which our customers commit for a specified term to purchase a minimum volume of sand annually at a pre-determined price. A portion of our supply agreements are take-or-pay contracts under which the customer will be obligated to pay us an amount designed to compensate us for lost margins for the applicable contract year on any minimum annual volumes that are not purchased by that customer. Total sales to customers currently under long-term contracts, including take-or-pay, fixed-volume and efforts-based contracts, accounted for 77% of our total Sand segment sales in 2014.

In our Fuel segment, our contract structure is designed to capture a stable margin, as the price differential between the refined products indices at which we purchase transmix and wholesale supply and the sales price of the refined products fluctuate in a fairly narrow range. While a meaningful portion of our transmix purchases is conducted on a spot basis, we currently purchase 69% of our supply of transmix pursuant to contracts with terms ranging from 12 to 48 months, with a volume-weighted average remaining duration of 22 months as of December 31, 2014. We use a hedging program that is designed to further mitigate the effects of our holding period, which is typically 7-10 days. In addition, we have throughput agreements with major refining and fuel marketing companies with terms of up to 33 months, which provide stable, fee-based revenue.

- Intrinsic logistics advantage. 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 has 4.5 miles of on-site rail track linked to a rail line owned by Union Pacific and our Barron facility has nearly nine miles of on-site rail track tied into a Canadian National rail line. Between our two Wisconsin rail yards, we have storage space for over 1,100 railcars. We also utilize a third rail loadout facility near our production facilities that has direct access to four class one rail lines:

the BNSF, the Canadian National, the Canadian Pacific, and the Union Pacific. As of December 31, 2014, we had a total of 5,099 railcars in our fleet, including 1,764 dedicated customer cars and 3,335 railcars under lease with a weighted average remaining term of 4.4 years. We have another 2,423 railcars under order for delivery in 2015 and an additional 2,459 railcars on order for delivery in 2016 and early 2017. As of December 31, 2014, we had 13 transload facilities in North America, each of which is positioned to serve a number of our target markets, and over half of which are capable of receiving unit trains.

Our logistics capabilities enable efficient loading of sand and minimize railcar turnaround times, and our Wisconsin dry plant facilities are able to accommodate unit trains. Our production facilities are able to accommodate and stage multiple

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unit trains, and five of our transload facilities are capable of receiving unit trains. In addition to our transload facilities, we also deliver to our customers' transload facilities. We believe we are one of a small number of frac sand producers connected to more than one Class One rail line, and this provides us with the capability to serve virtually all North American shale plays economically using a single line haul, which reduces transit time and freight cost for our customers. We also have economical means to transload from one production facility to another, allowing us additional flexibility to utilize our access to multiple Class One rail lines.

- Low cost operating structure. We believe that our operations are characterized by an overall low cost structure, which permits 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 reserves to our processing plants, which reduces operating costs;
  - recovery rates as high as 99% at our mines and plants, which also reduces operating costs;
  - expertise in designing, building, maintaining and operating advanced frac sand processing, storage and loading facilities and transmix processing and storage assets;
  - a large proportion of the costs we incur in our Sand segment are only incurred when we produce saleable frac sand;
  - proximity to major sand and fuel logistics infrastructure, minimizing transportation and fuel costs and headcount needs;
  - mineral royalty expenses that were less than 1% of our Sand revenues in 2014;
  - enclosed dry plant operations which allow full run rates in winter months, 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.

- Significant organic growth capacity. We commenced operations at our Arland facility in December 2014, and plan to bring another facility in Wisconsin online in the second half of 2015. Once this facility is online, we will have 9.4 million tons of permitted production capacity, of which 87% is currently under contract. We expect to produce and sell the remaining capacity to continue to establish new customer relationships through new long term contracts and to enter into spot sales at favorable market prices. We will also continue to add additional capacity as market conditions and specific customer demand build. We believe that this capacity will continue to position us well to attract customers currently relying on other frac sand producers when those customers have the opportunity to renegotiate their sand supply contracts or seek out a new supplier.
- 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. We currently sell to the twelve largest North American hydraulic fracturing service providers. 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. Further, we believe that these relationships will continue to benefit us in weaker markets relative to our peers. 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.
- Ability to identify and respond to changing market dynamics. We believe we have designed our assets and business model to permit us to adapt to changing market conditions. In our Sand segment, we have historically sought coarser reserves of Northern White sand than those sought by our competition, while our production at our Wisconsin facilities can optimize our production mix so that up to 20% of our production volume can fluctuate between coarse and fine sands. This optimization does not significantly impact our production yields or costs, yet we can still meet all API specifications, thereby allowing us the flexibility to respond efficiently to shifts in pricing and customer demand dynamics. We have also identified opportunities to utilize excess dry plant capacity at our Kosse, Texas frac sand processing facility to provide additional product offerings to our customers in the southwestern United States. We have significant reserves of fine mesh sand and believe that we will be well positioned to capture opportunities created by changing market trends in the relative prices of crude oil and dry natural gas. We have concentrated our

frac sand sales efforts in the most economical plays for producers, which should allow us to better withstand environments when oil and gas prices fall. Finally, we use a partnering model in our transload facilities, which allows us to relocate our transload facilities, often with the same operator, to remain close to the epicenter of drilling without necessitating large capital investment.

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- Experienced management team with industry specific operating and technical expertise. The top three management team members of our Sand segment have more than 75 years of combined industry experience. They have managed numerous frac sand mining and processing plants, successfully led acquisitions in the industry and developed multiple greenfield industrial minerals mining and processing operations. Most recently, this management team identified our existing Wisconsin facilities and designed, permitted and commenced each facility's operations within 12 months. We believe that our customers value our dedication to customer service, our reliable delivery, and our focus on high-quality product and that these give us a competitive advantage in the market. In addition, because of the experience of our staff, we believe that we are able to operate our sand facilities at a much lower per-ton overhead than our competition.

The top five management team members of our Fuel segment have significant experience and complementary skills in the areas of transmix processing, acquiring, integrating, financing and managing refined product terminals and biodiesel manufacturing and have in excess of 100 years of combined industry experience.

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 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. We have planned two additional 2.5 million ton per year dry plants, each backed by significant reserves and wet plant operations, at least one of which we intend to bring online some time in the second half of 2015. As of December 31, 2014, we also had thirteen transload facilities located throughout North America in the key basins where we deliver our sand, as well as a fleet of 5,099 railcars. In 2015, we expect to continue increasing both the number of transload sites in our network and the railcars in our fleet.

Our Sand segment has experienced rapid growth over 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 have positioned 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 on the surface and above the water table. We mine our sand using an open pit process, wherein 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. 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 to individual grains, cleanse it of impurities and unusable materials, and remove sand particles too fine to be of commercial use. 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 re-use all of the water in our wet process that does not evaporate. 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, Wisconsin and Kosse, Texas. Based on the reports of our third-party engineers, we have approximately 133.3 million tons of proven recoverable ISO and API quality sand reserves, including approximately 105.5 million tons of proven recoverable reserves that will supply our Wisconsin facilities. We are currently capable of producing up to 8.6 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' interconnectivity to rail and other transportation infrastructure afford us a cost advantage over our competitors and make us one of a select group of sand 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 wide range of high-quality sand that meets or exceeds all API specifications and includes a significant concentration of 16/30, 20/40 and 30/50 mesh sands, which have become the preferred sand for oil and liquids-rich gas drilling applications. We believe that our Wisconsin reserves provide us access to a disproportionate amount of coarse sand (16/30, 20/40 and 30/50 mesh sands) compared to other Northern White deposits located in Wisconsin's Jordan,

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St. Peter and Wonewoc formations. 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, which along with other coarse sands is currently subject to high demand from our customers and which we believe commands a significant price premium. The coarseness of our reserves also provides us with a meaningful cost advantage, as companies with a low concentration of coarse sand must typically expend the resources necessary to mine a large amount of fine grain sand that currently has less commercial value.
Our Wisconsin dry plants are fully enclosed, which means that we have three of the very few plants in Wisconsin that are capable of running year-round, regardless of the weather. 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. We did initiate a pilot program this most recent winter wherein we successfully operated a select number of our wet plants in temperatures as low as negative 20 degrees Fahrenheit through a proprietary enclosure process that we believe will allow us to run our wet plant facilities year round if required.
Our mine, wet plant and dry plant in Kosse, Texas operate year-round. 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, 2014.

Wet Plant Location (1)	Proven Recoverable Reserves (Millions of Tons) (2)	Lease Expiration Date (3)	Plant Capacity (Thousands of Tons)	2014 Production (Thousands of Tons)
New Auburn	27.8	March 2036	2,000	1,332
Thompson Hills	49.6	December 2037	1,600	322
FLS Mine	13.7	July 2037	1,200	1,189
Church Road	7.0	N/A	1,200	378
LP Mine	7.4	March 2038	1,000	1,005
Kosse, TX	27.8	N/A	1,600	306
Dry Plant Location (1)		On-site Railcar Storage Capacity (4)	Plant Capacity (Thousands of Tons)	2014 Production Volumes (Thousands of Tons)
Arland		N/A	2,500	124
Barron		650 cars	2,400	2,224
New Auburn		420 cars	1,400	1,394
Kosse, TX		N/A	600	299

(1) All facilities are located in Wisconsin, except for our Kosse facility.
(2) Reserves are estimated as of December 31, 2014 by third-party independent engineering firms based on core drilling results and in accordance with the SEC's definitions 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. Were we to operate our existing wet plants at full capacity, our reserves would supply us with fifteen years of Northern White frac sand and seventeen years of native Texas sand. We have information on several mineral deposits near and adjacent to our existing Northern White deposits that we believe we can economically mine as we deplete the reserves we currently lease.

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 smaller, finer frac sands. The low acid-solubility increases the integrity of the Northern White sand relative to other proppants with higher acid-solubility, especially in 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 believe the higher crush strength properties of our Northern White sand provides us with a significant competitive advantage in supplying frac sand.

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 133.3 million tons of proven recoverable mineral reserves as of December 31, 2014. 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, 2014. 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.

As of December 31, 2014, we owned 100% of our mineral reserves in Texas and 6.6% of our reserves in Wisconsin. We lease the remainder of our reserves in Wisconsin from third-party landowners, with leases expiring 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.

To opine as to the economic viability of our reserves, our independent third-party engineers reviewed our operations at the time of their proven recoverable reserve determination. Their findings were then incorporated into their reserve calculations and the reserve estimates reflect the quantity of sand that can be recovered under a similar cost structure.

The cutoff grade used in estimating our reserves considers only sand that will not pass through a 65 mesh screen as proven recoverable reserves, meaning that only sands with mesh sizes coarser than 65 are included in their estimates of our proven recoverable reserves. Cooper Engineering's estimate of our proven recoverable reserves considers only the proportion of sand grains falling between 20 and 70 mesh API sizes. As we sell sand with mesh sizes smaller than 65 from our Wisconsin facilities, the sum of our current year reserves and tons sold less our reserves acquired may exceed the reserves presented in prior periods.

The cutoff grade used by Westward in estimating our reserves considers only sand that falls between 20 and 140 mesh API sizes as proven recoverable 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 99%. We typically use heavy equipment to mine the loose sandstone deposit from wooded lands up to approximately 180 feet in elevation above surrounding seasonally farmed crops. The knoll from which we mine sand can contain up to 90 feet of unsalable overburden but yields pay zones that are up to 105 feet deep and that contain material that is predominately in the 20/60 grain size distribution.

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. We typically mine and wet-process sand from mid-March through mid-November as temperatures from mid-November through mid-March typically are too cold to run our wet processes, as the wet process will not operate efficiently if the water freezes. We have developed systems to heat those outdoor systems through which we use and recycle water that allows us to operate in weather that is below the freezing point of water, but we typically over-produce wet sand during the warmer months to ensure sufficient sand for the non-operating months.

New Auburn

Our New Auburn wet plant was constructed and commenced operations in 2011. The facility is a steel structure and relies primarily on industrial grade aggregate processing equipment to scrub and process up to 2.0 million tons per year of wet sand. It is strategically located approximately 12 miles from our New Auburn dry plant, to which we have year-round trucking access.

We lease the mineral rights to a 418-acre mine site adjacent to our New Auburn wet plant. As of December 31, 2014, the mine site contained approximately 27.8 million tons of proven recoverable reserves, of which substantially all were coarser than 70 mesh according to our third-party engineers. These leases expire in 2036.

As of December 31, 2014, excavating activities consisting of mining, overburden removal and reclamation had taken place on approximately 39 of the 418 acres of our New Auburn property.

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 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.

Thompson Hills

Our Thompson Hills mine consists of a series of seven leases in Barron County, Wisconsin, that together account for 580 acres and that contain approximately 49.6 million tons of proven recoverable sand reserves, based on the report of our third party independent mining engineers. This facility also includes a wet plant with the capacity to process 1.6 million tons per year. This mine is located approximately 25.5 miles from our Barron dry plant and approximately 15 miles from our New Auburn dry plant.

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. As of December 31, 2014, excavating activities consisting of mining, overburden removal and reclamation had taken place on approximately160 acres of our Thompson Hills property.

FLS mine

Our FLS mine, formerly referred to as our FLS/Arland mine, consists of five adjacent mineral deposits in Barron, Wisconsin that together account for 364 acres and that contain approximately 13.7 million tons of proven recoverable sand reserves, based on the report of our third-party independent mining engineers. This facility also includes a wet plant with the capacity to process 1.2 million tons per year. This mine is located approximately 11.5 miles from our Barron dry plant. As of December 31, 2014, excavating activities consisting of mining, overburden removal and reclamation had taken place on approximately 95 acres of our FLS property.

Church Road

In July 2014, we acquired certain assets and obligations of Midwest Frac and Sands LLC (“Midwest”), which includes 130 acres that contain approximately 7.0 million tons of provable recoverable sand reserves, based on the report of our third party independent mining engineers. The property also contains a wet plant that we constructed for Midwest in 2012 that has the capacity to process 1.2 million tons per year. The mine is located less than one mile from our Arland dry plant. As of December 31, 2014, excavating activities consisting of mining, overburden removal and reclamation had taken place on approximately 35 acres of our Church Road property, including activities that had taken place prior to our acquisition.

LP Mine

In 2013, we entered into a series of leases in Barron, Wisconsin, adjacent to our FLS Mine. These account for 145 acres and contain approximately 7.4 million tons of proven recoverable sand reserves, based on the report of our third party independent mining engineers. In 2014, we built a wet plant at this site that has the capacity to process 1 million tons per year. The mine is located approximately two miles from our Arland dry plant. As of December 31, 2014, excavating activities consisting of mining, overburden removal and reclamation had taken place on approximately 42 acres of our LP Mine.

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 99% and controlling attributes that include sand grain crush strength and size distribution. As of December 31, 2014, the Kosse mineral deposit contained approximately 27.8 million tons of proven recoverable reserves, which we process into a high-quality, 100 mesh frac sand that is particularly well suited to drilling for dry natural gas. The wet plant at our Kosse facility is capable of producing up to 2 million tons per year of wet sand. We are not obligated to make any royalty payments in connection with our mining operations at this location. We use heavy equipment to mine sand from the open-pit. The current mining area of our Kosse property covers approximately 95 acres and no reclamation has been performed.

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Dry Plant Facilities

Arland

Our Arland dry plant is located in the township of Arland, Wisconsin in Barron County on 22 acres of land that we own. The facility is strategically 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, or roughly 80 railcars. 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," manufactured by Rotex. We load sand produced at Arland into trucks that we then transload to either our Barron and New Auburn facilities or to a third-party rail loadout approximately 75 miles from our Arland facility. We completed construction of the Arland facility in November 2014, and brought the facility online in December of that year.

For the year ended December 31, 2014, our Arland facility produced approximately 124,000 tons of Northern White sand.

Barron

Our Barron dry plant is located in the township of Clinton, Wisconsin in Barron County on 83 acres of land that we own. The facility is strategically located on a county road, which gives us year round trucking access, and is situated along a 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 and regardless of weather conditions, or roughly 80 railcars, and has on-site railcar loading facilities capable of loading up to approximately 10,000 tons of frac sand into railcars per day. 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 Rotex screeners. Our railyard at Barron consists of 18 spur tracks and is capable of storing up to 650 railcars. We completed construction of the Barron facility in 2012, and brought the facility online in the last two weeks of that year.

At Barron, we utilize approximately nine miles of existing rail track that connects our facility to the rail line owned by CN, making this facility one of only three active Wisconsin-based frac sand mines located on the CN line. Our direct connection to the CN line 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 markets in Latin America. We are currently one of only two frac sand providers in Wisconsin located on CN's high capacity rail line, which is designed for railcars with a 286,000 pound capacity. This allows us to transport heavier loads and results in reduced transportation costs relative to competitors that only have access to lower capacity infrastructure.

For the year ended December 31, 2014, our Barron facility produced approximately 2.2 million tons of Northern White sand.

New Auburn

Our New Auburn dry plant is located approximately 12 miles from our New Auburn mine and is strategically located near a county road that provides year-round trucking access. The facility is on 37 acres of land that we own in the town 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 and regardless of weather conditions, or roughly 50 railcars, and has on-site railcar loading facilities capable of loading up to approximately 10,000 tons of frac sand into railcars per day. 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 Rotex screeners. We constructed the facility and brought it online in late 2011, and fully enclosed the facility in mid-2012. In 2013 we completed the installation of our sixth Rotex screener that allowed us to increase our capacity to 1.4 million tons per year, the maximum allowable under our air permit.

Once processed and dried, sand from our New Auburn facility is stored in one of five on-site silos with a combined storage capacity of 4,500 tons. In addition to the 4,500 tons of silo capacity, we possess 4.5 miles of on-site rail track

(3.0 miles of which is owned and 1.5 miles of which we access through a long term lease) that is tied into a rail line owned by UP and that is used to stage and store empty or recently loaded customer railcars. Because of the cost efficiencies of shipping frac sand by rail, our strategic location adjacent to a UP short rail line provides our customers with the ability to transport Northern White frac sand from our New Auburn facility to all major unconventional oil and natural gas basins currently producing in the United States and Canada with direct access to high-activity areas of oil production in Texas, Oklahoma, Colorado and the western United States. Our location in Wisconsin also provides our customers with economical access to barging terminals on the Mississippi River as well as access to Duluth, Minnesota, for loading onto ocean going vessels for international delivery.

For the year ended December 31, 2014, our New Auburn facility produced approximately 1.4 million tons of Northern White sand.

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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 upgraded the facility in 2009, and later redeployed some of its components to build our New Auburn facility. We are currently engaged in a second upgrade designed to de-bottleneck our production process.

The plant produces 100-mesh native Texas sand and is capable of producing a higher-cut 40/70 frac sand as well. In the past, we have also shipped washed Northern White sand from our Wisconsin operations in unit trains to Kosse where it was dried, screened and resold to oil field service companies servicing unconventional resource plays located in south and west Texas. The Kosse facility has three dedicated on-site 1,000-ton storage silos designed for loading trucks for delivery to local and regional markets.

For the year ended December 31, 2014, our Kosse facility produced and sold approximately 299,000 tons of frac sand. We also sell the sand to non-energy end users, specifically as sports sand for golf courses and stadiums.

Additional Projects

We are currently developing two other dry plants in Wisconsin near our existing facilities and outside Barron County. The first project is in Independence, Wisconsin, which is located in Trempeleau County. This project, which has been in development since the late first quarter of 2014, is designed as a 2.5 million ton per year dry plant, supported by a wet plant and mine. As of December 31, 2014, we had invested a total of $17.4 million in the Independence project, including leveling and preparation of the building site and pre-ordering longer lead-time equipment. We are also working to develop another 2.5 million ton per year dry plant, supported by multiple mines and wet plants. Based on the contracts we have in place and continued customer demand, we intend to bring at least one of these facilities online during the second half of 2015 and the other online during 2016, subject to market conditions. The equipment that we pre-ordered for the Independence facility can be used in either of the two dry plants, as their design is substantially identical to our existing Arland and Barron facilities, as well as to one another.

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, 2014, we sold approximately 78% of our sand FOB mine and 22% 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 several of our customers still 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 60 miles of the wellhead. Given the relative weight of transportation and logistics expenditures as a percentage of total delivered frac sand cost, we believe such a service offering has allowed, and will continue to allow, us to generate incremental revenue and reach a broader set of customers while providing our customers with a streamlined order process and a lower total delivered product cost. Currently, we have built a fleet of company-leased and customer-committed railcars, created a network of leased transload and terminal storage sites located near major shale plays and designed a supply chain management system that allow us the ability to flexibly and efficiently coordinate rail, truck and storage assets with customer order information. Several customers currently utilize our total supply chain solution and pay us fees for the service.

We believe that the connectivity of our Barron facility to the CN, combined with our connection with the UP at our New Auburn facility and our connection with four Class One rail lines in Minnesota, provide us enhanced flexibility to accommodate customers located in shale plays throughout North America. We also believe that access to these four rail lines allows us to provide single line hauls to most shale plays, resulting in fast transit times and a low delivered cost per ton. Using our existing on-site rail track, we have shipped sand in unit trains, which are dedicated trains (typically 80 to 120 railcars in length) chartered for a single delivery destination that usually receive priority scheduling and result in a more cost-effective method of shipping than standard rail shipment, out of both our Barron and New Auburn facilities. In addition, we have the capability to transload product from any of our Wisconsin facilities to either Barron or New Auburn, allowing us to fulfill special orders in an expedited basis regardless of the optimal rail line.

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 near their job sites. As a result, customers place a premium on a frac sand supplier's ability to maintain predictable and efficient product shipping schedules. The integrated nature of our production planning, railcar staging and product loading

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operations, combined with our more than seven miles of on-site rail infrastructure, provide us with a competitive advantage in serving customer needs as 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 further down the supply chain, we developed a network of transload facilities within a number of the major basins that we serve. As of December 31, 2014, we had agreements with operators of thirteen transload storage facilities in North America. Below is a summary of the transload sites that we operate out of at December 31, 2014.

Transload Location by Basin	Transload Sites as of December 31, 2014	Transload Sites Capable of Receiving Unit Trains	2014 Volume Sold (Thousands of Tons)
Bakken Shale	1	1	154.1
Eagle Ford Shale	1	1	83.6
Haynesville Shale	1	1	—
Marcellus / Utica Shales	4	—	339.6
Mid-Continent Basin	1	1	46.9
Permian Basin	2	—	92.7
Western Canadian Sedimentary Basin	3	1	284.8
Total	13	5	1,001.7

In selecting transload sites, we focus on a number of factors, including distance to the wellhead and customer needs that are specific to the basin and drilling activity, as well as whether or not the site is capable of receiving unit trains. Where available, we use silos to store our sand and work with the transload operators to ensure that in those locations where our sand is not the only sand sold that our sand is not co-mingled with that of our competitors; we refer to this as vertical storage. Where practical, we also utilize rolling storage, in which the sand remains in the railcar until it is loaded directly into a truck that will deliver the sand to the drill site. In general, we seek long-term relationships with existing transload operators that have multiple sites in and near the basins that we serve.

To maintain the maximum flexibility and respond promptly to customer needs, we have focused on enhancing our railcar fleet. 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, 2014, we had a total of 5,099 railcars in our fleet, including 1,764 railcars that are owned or leased by our customers but dedicated to us, and 3,335 railcars that we lease with a weighted average remaining term of 4.4 years. We anticipate that we will be able to renew these leases at favorable terms when they expire. We also have ordered an additional 4,882 railcars which we intend to lease, 2,423 of which have been or are expected to be delivered during 2015.

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 and quality, 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, and are in the process of obtaining the remaining necessary permits for facilities under construction.

Fuel Segment

Our Fuel segment consists of our facilities 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, 2014 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	78,515	27,418	11,990	102,942
Birmingham, AL	76,650	38,096	120,335	21,966	107,723

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 rack to third party distributors as well as off-road customers such as railroad operators. While a meaningful portion of our transmix business is conducted on a spot basis, we currently purchase approximately 69% of our supply of transmix pursuant to contracts having a volume-weighted average remaining duration of 22 months as of December 31, 2014. We design our contract structure 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 products tends to be stable.

In our wholesale fuel business, we purchase fuel which is delivered to our tanks via pipeline, and which we then subsequently sell over our truck rack. We are also a shipper on the Colonial Pipeline and Plantation Pipeline, which allows us to bring refined products to our Birmingham facility from Gulf Coast refineries without paying third parties separate shipping charges. Our average holding period for transmix and wholesale gallons is 7-10 days, which serves to minimize 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. In 2013, we installed additive systems, which allow us to sell branded gasoline in addition to the unbranded gasoline we have historically sold, which we believe continue to 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.

In both our transmix and wholesale businesses, we analyze our business by looking at three components of margin contribution. Our base margin is the difference between the price our customers pay for a refined product less the price we pay and any processing costs, viewed as if both the purchase and sale occurred simultaneously. This base margin is usually the largest component of our gross margin per ton. This base margin tends to be greatest in periods of contango and lowest in periods of backwardation. The other two components are (1) the combined effects of holding cost (the price volatility during the 7-10 days we have possession of the refined product) and our hedging program and (2) the combined effects of the cost of RINs and the costs to blend off-spec product to acceptable standards. Because we are a net producer of RINs and because our blending program takes advantage of market imbalances wherever possible, this second component tends to be positive in most periods.

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

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, beginning in 2015, all new locomotives purchased by railroads will be Tier 4, meaning that they cannot accept 500 ppm diesel. Railroads are permitted to continue utilizing Tier 3 and prior locomotives, but over time, their fleets will transition more and more towards equipment that cannot utilize LSD. As a result, 500 ppm sulfur diesel will be phased out of the locomotive market over a several year period 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. Regardless, as mentioned above, we are taking steps to ensure that all of the diesel we sell is eventually 15 ppm or less.

Jet fuel continues to contain sulfur levels well in excess of 15 ppm because the sulfur acts as a lubricant for jet engines. As a result, when jet fuel is part of a shipment of transmix, the diesel that results from the transmix separation process has a sulfur content that exceeds ULSD standards and can approach, or even exceed, 200 ppm. Because of this, we and other transmix processors are working to implement solutions to maximize the value of the LSD produced from transmix containing jet fuel. One option is to continue to find non-traditional customers, including small railroads and marine applications that can still use LSD. Another solution is to truck LSD to a refinery that has a hydrotreater that can remove sulfur efficiently from the diesel. Both of these options involve additional transportation costs that could lower the per-gallon base margin of the processed transmix. We have elected to build our own hydrotreaters at both our DFW and Birmingham facilities in order to ensure all the diesel we produce is ULSD. Once these hydrotreaters are completed, which we expect to be early 2016, we believe that we will be able to both increase our per-gallon base margin as well as source additional supplies of transmix and off-spec fuel that is lower cost because of the higher sulfur content.

We believe we have several 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 75% of capacity, our Birmingham transmix tower, which is the newest transmix tower in the United States, was running at half of its design capacity at the end of 2014. In addition, we believe that our transmix business model can be replicated successfully in other regions of the United States, and we actively evaluate potential acquisitions of bulk fuel terminals that have similar characteristics to our existing operations in Texas and Alabama. We also continue to seek additional terminaling customers, and regularly analyze our wholesale customers to maximize profitability.

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 sulfur diesel from both our transmix processing and bulk purchases. Our Dallas-Fort Worth facility is strategically located in the Dallas-Fort Worth metropolitan area on approximately 20 acres of land that we own and provides us access to an attractive market for our fuel products and direct connections to third-party refined products pipelines directly serving our transmix processing units and adjacent storage tanks. Specifically, we can receive transmix and bulk fuel product via three different pipelines at our Dallas-Fort Worth facility: the 28-inch and 10-inch pipelines owned by Explorer Pipeline Company and a major independent refiner's proprietary products pipeline. The 10-inch Explorer and independent refiner's pipelines terminate within a mile of our Dallas-Fort Worth facility. Additionally, we can receive inbound product via truck.

We own two transmix processing units at our Dallas-Fort Worth facility. These transmix processors were constructed in 1996 and 2003 and have a combined processing capacity of approximately 7,000 barrels of transmix per day. We purchased and refurbished our second processor in 2005. We sold an average of 5,122 barrels per day of refined products processed from transmix during the year ended December 31, 2014.

We purchase an average of nearly 48,000 barrels of ultra-low sulfur diesel each month under short-term purchase contracts. In addition, we receive throughput fees from two customers who store their own refined fuel products at our terminal.

We have 49 storage tanks at our Dallas-Fort Worth facility with total storage capacity of approximately 250,000 barrels. Additionally, we lease approximately 25,000 barrels of storage space at a fuel 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 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 at our Dallas-Fort Worth facility 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. The truck rack at our Dallas-Fort Worth facility is fully automated so that 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 sulfur 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.

Our Birmingham facility is strategically located on approximately 40 acres of land that we own and provides us access to an attractive market for our fuel products and direct connections to third-party refined product pipelines directly serving our transmix processing units and adjacent storage tanks. Specifically, we can receive transmix and bulk fuel product via spurs from the Colonial and Plantation Pipelines, on both of which we are also shippers. Additionally, we can receive inbound product via truck.

We own one transmix processing unit at our Birmingham facility that has a processing capacity of approximately 5,000 barrels of transmix per day. This unit was constructed and placed in service during 2009. We sold an average of approximately 2,485 barrels per day of refined products processed from transmix at this facility during the year ended December 31, 2014.

We have 44 storage tanks at our Birmingham facility 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

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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 Birmingham facility's four-lane truck rack has a maximum daily capacity of 384 full-sized tank-trucks with an average utilization of approximately 100 trucks per day. In addition to gasoline and diesel, we also offer our customers biodiesel, ethanol and other additive blending at the rack. The terminal and truck rack at our Birmingham facility are fully automated so that 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.

In December 2012, we placed an idled biodiesel refinery at our Birmingham facility back into service and began commercial sales. 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 approximately 80% 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 2 million gallons of biodiesel fuel annually, and produced 0.9 million gallons during the year ended December 31, 2014.

We also operate equipment at our Birmingham facility that allows us to offer customers a unique alternative for the disposal of refined petroleum tank bottoms and petroleum contact waters (“PCW”). By reclaiming fuels from these wastes and placing them back into fuel service, our reclamation services eliminate the need for hazardous waste disposal. We also have 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 the sand we produce 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 2014.

The sand in our reserves is, we believe, among the coarsest Northern White sand available. Typically, coarser sand is used in oil and liquids rich hydraulic fracturing, while natural gas extraction typically utilizes a finer grade of sand. Generally, oil field equipment requires less maintenance and provides more efficient operations when utilizing coarser frac sand, which, we believe, makes coarser sand generally preferred over finer sands. For the year ended December 31, 2014, approximately 1% of our sand sales were of our 16/30 product, 19% were of our 20/40 product, 37% were of our 30/50 product, 33% were of our 40/70 product, and 9% were of our 100 mesh product. These percentages include specialty cuts, such as our 20/30 “high cut,”, which would be included in our 20/40 percentage and which often results in a higher price on a FOB plant equivalent basis.

In 2014, total sales to customers currently under long-term contracts, including take-or-pay, fixed-volume and efforts-based contracts, accounted for 77% of our total Sand segment sales. As of December 31, 2014, we have 6.9 million tons under long-term contract with a weighted average remaining term of four years. Over the next 18 months, only three contracts for 700,000 tons are scheduled to expire or renew. Of the product we have under long-term contract, 21% is under take-or-pay contract, 6% is under a fixed-volume contract, and 73% is under an efforts-based contract. All three of these contracts have minimum volumes that the customer must purchase from us at an agreed-upon price. If a customer fails to perform under these contracts, each contract type has a different remedy:

under take-or-pay, there is a specific remedy stated in the contract's liquidated damages clause; under a fixed-volume or efforts-based contract, damages are usually determined in arbitration. Efforts-based contracts also have certain market-out clauses wherein a customer may be relieved of his purchase obligation if he is unable to re-sell or use the sand because of adverse market conditions, such as a moratorium on the use of raw sand to fracture-stimulate a hydrocarbon well. Contracts also have a number of mechanisms that will allow the contracted price to fluctuate, subject to certain ceilings and floors. The majority of our contracts have annual escalators tied to the change in the Producer Price Index (“PPI”) as published by the United States Bureau of Labor Statistics. A limited number of our contracts may be adjusted to move the contracted price closer to the

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spot market price. As all of our contracts were made at a price that was below the spot market price at the time of the contract, we believe that our downside on these contracts is limited relative to our upside.

Two customers represented 29% and 16% of our total sand sales for the year ended December 31, 2014.

Due to recent expansions in the supply of frac sand and processing capacity and the expectation of continued expansions, as well as uncertainty surrounding the future price of crude oil and natural gas, we believe that frac sand customers are increasingly reluctant to enter into take-or-pay contracts that expose them to pre-determined financial liability for failure to take delivery of minimum volumes of frac sand. Customers increasingly pursue efforts-based contracts over take-or-pay or fixed-volume contracts, and tend to contract at significantly lower levels than they ultimately plan to purchase. We also believe customers will be increasingly focused upon the relative quality of sand reserves, logistics capabilities and service level provided by the frac sand provider. As a consequence, we believe that we will be able to secure significant orders from customers over and above their contract minimums.

We believe that we will continue to sell a majority portion of our uncontracted tons to contract customers, and we will continue to seek additional long-term contracts with both existing contract customers and customers who are currently purchasing sand through a purchase order or spot basis. In the event that one or more of our current contract customers decides not to continue purchasing our frac sand following the expiration of its contract with us, we believe that we will be able to sell the volume of sand that they previously purchased to other customers through long-term contracts or sales on the spot market. We also intend to continue in our efforts to diversify our customer base. During the year ended December 31, 2014, we converted eight customers from purchase order-only to contract customers, increased contracted commitments from five customers and added twenty new customers.

Fuel

Our primary fuel processing and distribution markets are the Dallas-Fort Worth metropolitan area and Birmingham, Alabama. Combined, these markets contain approximately 6.4 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 were installed in 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 an important component of frac sand operations, but is viewed as a less differentiated skill set that can be performed efficiently by specialized third party providers. We mine our own frac sand reserves at our Kosse facility, and have engaged experienced mining contractors to manage excavation activities at our Wisconsin facilities.

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. 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. 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 2015, which should significantly reduce the cost to produce sand on a per ton basis in 2015.

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.

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We currently purchase approximately 69% of our supply of transmix pursuant to contracts with terms ranging from 12 to 48 months, with a volume-weighted average remaining duration of 22 months as of December 31, 2014. The remainder of our supply of transmix is purchased on a spot basis. For the year ended December 31, 2014, our three largest suppliers of transmix accounted for approximately 25%, 19% and 12% of our total transmix purchases. The contract with our largest supplier for 2014 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 if those trends continue. 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 are one of the five largest producer of frac sand in 2014 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 an increased demand for hydraulic fracturing services and related proppant supplies. Due to this increased demand, existing or new frac sand producers could expand their frac sand production capacity, thereby increasing competition. 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 has prevented these smaller competitors from prospering in the market on a long-term basis. Further, the large capital requirements to locate storage and transload facilities into the various North American shale plays, as well as to assemble and maintain a significant fleet of railcars and other logistics capabilities, creates a significant additional barrier to entry for those considering whether to enter the market. We believe that industry consolidation and the exit from the market by less successful competitors will continue 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 producer 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.

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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

Because it is challenging to process raw sand during sub-zero temperatures, frac sand is typically washed only eight months out 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 and resulting in seasonal variations in our cash flow. We may also be selling 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 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 in contango, and marginally lower earnings in periods where refined product prices are in backwardation.

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 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. We believe that we are in substantial compliance with all of these environmental laws and regulations.
Air emissions. Our operations are subject to the Clean Air Act, as amended (the “CAA”), and comparable state and local laws, which 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. Amendments to the CAA, including, among others, the CAA Amendments of 1990, require most industrial operations in the United States to incur capital expenditures

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to meet the air emission control standards that are developed and implemented by the EPA and state environmental agencies. 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. While we believe that we are in substantial compliance with the CAA and its implementing regulations, as well as similar state and local laws and regulations, frequently changing and increasingly stricter requirements, future 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. We believe that we are in substantial compliance with applicable SIP requirements. 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.

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. 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.

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Climate change. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of natural gas, are examples of greenhouse gases (“GHGs”). In recent years, the U.S. Congress has considered legislation to reduce 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 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. 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.

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

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 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 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 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. 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 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. While some of our facilities may be located in areas that are designated as habitats for endangered or threatened species, we believe that we are in substantial compliance with the ESA. 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

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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, 2014, our general partner employed 282 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-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. 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 are 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. 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. Beginning in the fourth quarter of 2014 and continuing into 2015, the prices of crude oil and related products have dropped substantially. Natural gas prices have generally remained below $4.50 per mcf for the past six years. Worldwide economic, political and military events, including war, terrorist activity, events in the Middle East and initiatives by the Organization of the Petroleum Exporting Countries 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;
- 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.

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 2014, our top five Sand customers represented 65% of sales from our Sand operations. During 2014, our top five Fuel customers represented 42% 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

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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.

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 amount 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.

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.

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

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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 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-

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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 69% 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 22 months as of December 31, 2014. For the year ended December 31, 2014, our three largest suppliers of transmix accounted for 25%, 19% and 12% of our total transmix purchases. The contract with our largest supplier for the year ended December 31, 2014 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 expires 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.

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Increases in the price of diesel fuel may adversely affect our 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 operations are dependent on earthmoving equipment, railcars and tractor-trailers, 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 from our New Auburn mine, deliver the raw frac sand to our processing facility and move the sand from our wet plant to our dry plant, and 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 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

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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.

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 $221.9 million million as of December 31, 2014. 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 we 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

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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.

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 competition for experienced operational and field technicians increases as other energy and manufacturing companies' needs for the same personnel 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 processing, 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 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.

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. The EPA has proposed a level for biomass-based diesel for 2014 of 1.28 billion gallons under the RFS in the Energy Independence and Security Act of 2007, but has not yet finalized that level. 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, or GHGs. At the federal level, regulatory actions are already underway to reduce GHGs from the oil and gas sector, and further administrative actions are likely to continue. While 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. 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 has adopted regulations controlling GHG emissions under its existing authority under the federal Clean Air Act, as amended, or the CAA. In 2009, the EPA officially published its findings that emissions of carbon dioxide, methane 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. For example, in 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. In 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. The rule requires reporting of GHG emissions by such regulated facilities to the EPA annually. 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 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.
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.

The federal Safe Drinking Water Act, or the SDWA, regulates the underground injection of substances through the Underground Injection Control Program, or the UIC Program. Currently, with the exception of certain hydraulic fracturing activities involving the use of diesel, hydraulic fracturing is exempt from federal regulation under the UIC Program, and the hydraulic fracturing process is typically regulated by state or local governmental authorities. Although we do not directly engage in hydraulic fracturing activities, our oil and natural gas industry customers purchase our frac sand for use in their hydraulic fracturing operations. The EPA has taken the position that hydraulic fracturing with fluids containing diesel is subject to regulation under the UIC Program, specifically as “Class II” UIC wells and, in 2012, the EPA issued draft guidance for federal SDWA permits issued to oil and natural gas exploration and production operators using diesel during hydraulic fracturing activities. Also in 2012, the EPA published final rules that establish new air emission controls for oil and natural gas production and natural gas processing operations. The final rule requires new standards on certain hydraulically-fractured wells constructed or re-fractured after January 1, 2015. At the same

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time, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities and released initial results in December 2012 and a subcommittee of the Secretary of Energy Advisory Board (the “SEAB”) of the U.S. Department of Energy was tasked with recommending steps to improve the safety and environmental performance of hydraulic fracturing. As part of these studies, the EPA and the SEAB subcommittee have requested that certain companies provide them with information concerning the chemicals used in the hydraulic fracturing process. In other investigatory activities, the EPA has announced plans to propose standards for the treatment and discharge of waste water resulting from hydraulic fracturing in 2015 and the DOI, announced 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. The DOI published a supplemental notice of proposed rulemaking on May 24, 2013 which replaced the proposed rulemaking issued by the agency in May 2012. These studies and initiatives, depending on their results, could spur proposals to regulate hydraulic fracturing under the SDWA or otherwise. The SEAB subcommittee issued a final report in November 2011 recommending, among other things, measures to improve and protect air and water quality, improvements in communication among state and federal regulators, reduction of diesel fuel in shale gas production, disclosure of fracturing fluid composition and the creation of a publicly accessible database organizing all publicly disclosed information with respect to hydraulic fracturing operations. Congress previously considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. If this or similar legislation becomes law, the legislation could establish an additional level of regulation that may lead to additional permitting requirements or other operating restrictions, making it more difficult to complete natural gas wells in shale formations. This could increase our customers' costs of compliance and doing business or otherwise adversely affect the hydraulic fracturing services they perform, which may negatively impact demand for our frac sand products.

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.

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 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;

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- 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;
- 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.

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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.

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.

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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.

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We have material weaknesses in our internal control over financial reporting. These material weaknesses are attributable, in part, to the rapid growth and expanding complexity of our Sand segment. If one or more material weakness persists or if we fail to establish and maintain effective internal control over financial reporting, our ability to accurately report our financial results could be adversely affected.

In connection with the audit of our consolidated financial statements for the year ended December 31, 2014, we and our independent registered public accounting firm identified material weaknesses in our internal controls over financial reporting. These material weaknesses relate to our inability to effectively perform, complete, document and track various information technology general control activities and our inability to effectively perform and document certain daily recurring activity controls in our Sand segment. Both material weaknesses stem, in part, from our inability to staff, train and monitor a sufficient number of accounting and technology personnel in response to the rapid growth of sales volume and operational complexity in our Sand segment.

We are in the process of dedicating resources and effort to remediate these material weaknesses and improve our internal control in these areas. Our remediation plan includes (i) performing an administrative headcount and competency gap analysis to determine the appropriate level of staffing, (ii) hiring qualified accounting, monitoring and information technology staff, (iii) incorporating training of information technology and accounting personnel where appropriate to improve competencies and understanding of our policies and (iv) increasing managerial monitoring activities over remediation efforts in areas of particular weakness. However, there can be no assurance that we will remediate these material weaknesses or avoid future weaknesses or deficiencies.

Any failure to remediate these material weaknesses and any future weaknesses or deficiencies or any failure to implement required new or improved controls or difficulties encountered in their implementation could cause us to fail to meet our reporting obligations or result in material misstatements in our financial statements. If our management were to conclude in future reports that our internal control over financial reporting was not effective, investors could lose confidence in our reported financial information, and the trading price of our common units could be impacted. Failure to comply with Section 404 of Sarbanes-Oxley could potentially subject us to sanctions or investigations by the SEC, FINRA or other regulatory authorities, as well as increasing the risk of liability arising from litigation based on securities law.

If we fail to develop or 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 our efforts to develop and maintain our internal controls will be successful, 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 develop or 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.

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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, members of the U.S. Congress propose and consider 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. 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. 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. 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 or any other matter affecting us. The IRS may adopt positions that differ from the positions we take, and the IRS's positions may ultimately be sustained. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take 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.

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

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

We prorate our items of income, gain, loss and deduction for federal income tax purposes between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations. The U.S. Treasury Department has issued proposed regulations that provide a safe harbor pursuant to which publicly traded partnerships may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge this method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose common units are 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

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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 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 - Ft. 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.

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.

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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 23, 2015, the closing market price for the common units was $54.00 per unit. As of February 23, 2015, there were 23,718,961 common units outstanding. There were approximately 34,744 record holders of common units on December 31, 2014. 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
June 30, 2013	$21.44	$16.44	N/A
September 30, 2013	$33.00	$20.06	$0.37
December 31, 2013	$45.03	$29.99	$0.86
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

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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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,			
	2014	2013	2012	2011
	($ in thousands, except per unit data)			
Statement of Operations Data:				
Revenues	$1,111,254	$873,255	$624,096	$377,488
Cost of goods sold (excluding depreciation, depletion and amortization)	950,006	767,911	575,408	359,822
Depreciation, depletion and amortization	24,803	20,828	9,119	6,880
Selling, general and administrative expenses	38,723	26,835	10,256	9,221
IPO transaction-related costs	—	10,966	—	—
Impairment charges	—	—	—	762
Income from operations	97,722	46,715	29,313	803
Interest expense, net	7,394	10,586	11,055	3,371
Loss (gain) on extinguishment of debt	—	907	377	(472)
Gain on extinguishment of trade payable	—	—	—	(1,212)
Other	611	(334)	605	(300)
Income (loss) before provision for income taxes	89,717	35,556	17,276	(584)
Provision for income taxes	638	386	81	101
Net income (loss)	89,079	35,170	$17,195	$(685)
Less Predecessor net income before May 14, 2013	—	13,124		
Post-IPO net income	$89,079	$22,046		
Earnings per common unit (basic)	$3.70	$0.92		
Earnings per common unit (diluted)	$3.70	$0.92		
Balance Sheet Data (at year end):				
Property, plant and equipment, net	$238,657	$146,131	$131,414	$88,056
Total assets	$436,968	$323,016	$195,789	$127,580
Long-term debt	$222,904	$97,511	$145,938	$99,506
Statement of Cash Flow Data:				
Net cash provided by (used in):				
Operating activities	$86,161	$58,036	$1,137	$(3,606)
Investing activities	$(88,172)	$(38,009)	$(39,075)	$(14,754)
Financing activities	$			