Sprague Resources LP
Form 10-K
March 27, 2014
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark one)

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

For the Fiscal Year Ended December 31, 2013

or

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

For the transition period from ______ to ______

Commission File Number: 001-36137

Sprague Resources LP

(Exact name of registrant as specified in its charter)

Delaware	**45-2637964**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification Number)**

185 International Drive

Portsmouth, New Hampshire 03801

(Address of principal executive offices, including zip code)

Registrant s telephone number, including area code: (800) 225-1560

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

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

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

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted to its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Registration S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x 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. x

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

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

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

As of June 30, 2013, the last business day of the registrant s most recently completed second quarter, the registrant s equity was not listed on a domestic exchange or over-the-counter market. The registrant s common units began trading on the New York Stock Exchange on October 25, 2013.

The registrant had 10,078,636 common units and 10,071,970 subordinated units outstanding at March 20, 2014.

Documents Incorporated by Reference: None

SPRAGUE RESOURCES LP

ANNUAL REPORT ON FORM 10-K

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PART I

Item 1. Business

As used in this Annual Report on Form 10-K (Annual Report), unless the context otherwise requires, references to Sprague Resources, the Partnership, we, our, us, or like terms, when used in a historical context prior to October 30, 2013, the date on which we completed an initial public offering of common units representing limited partner interests in Sprague Resources LP, refer to Sprague Operating Resources LLC, our Predecessor for accounting purposes and the successor to Sprague Energy Corp., also referenced as our Predecessor or the Predecessor and when used in the present tense or prospectively, refer to Sprague Resources LP and its subsidiaries. Unless the context otherwise requires, references to Axel Johnson or the Parent refer to Axel Johnson Inc. and its controlled affiliates, collectively, other than Sprague Resources, its subsidiaries and its general partner. References to Sprague Holdings refer to Sprague Resources Holdings LLC, a wholly owned subsidiary of Axel Johnson and the owner of our general partner. References to our general partner refer to Sprague Resources GP LLC.

Our Partnership

We are a Delaware limited partnership formed in June 2011 by Sprague Holdings and our general partner to engage in the storage, distribution and sale of refined petroleum, what we refer to as refined products, and natural gas, and we also provide storage and handling services for a broad range of materials.

In October 2013, we completed an initial public offering of common units representing limited partner interests in the Partnership (the IPO). Our common units now trade on the New York Stock Exchange (the NYSE).

We are one of the largest independent wholesale distributors of refined products in the Northeast United States based on aggregate terminal capacity. We own and/or operate a network of 15 refined products and materials handling terminals strategically located throughout the Northeast that have a combined storage capacity of approximately 9.2 million barrels for refined products and other liquid materials, as well as approximately 1.5 million square feet of materials handling capacity. We also have an aggregate of approximately 1.4 million barrels of additional storage capacity attributable to 41 storage tanks not currently in service. These tanks are not necessary for the operation of our business at current levels. In the event that such additional capacity were desired, additional time and capital would be required to bring any of such storage tanks into service. Furthermore, we have access to more than 60 third-party terminals in the Northeast through which we sell or distribute refined products pursuant to rack, exchange and throughput agreements.

Our principal executive offices are located at 185 International Drive, Portsmouth, New Hampshire 03801. Our telephone number is (800) 225-1560. Our internet address is http://www.spragueenergy.com. We make available through our website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, or the Exchange Act, as soon as reasonably practicable after we electronically file such material with, or furnish such material to, the Securities and Exchange Commission, or the SEC. The SEC maintains an internet site at http://www.sec.gov that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC.

We operate under four business segments: refined products, natural gas, materials handling and other operations. Our refined products segment purchases a variety of refined products, such as heating oil, diesel, residual fuel oil, kerosene, jet fuel and gasoline (primarily from refining companies, trading organizations and producers), and sells them to our customers. We have wholesale customers who resell the refined products we sell to them and commercial customers who consume the refined products we sell to them. Our wholesale customers consist of more than 1,000 home heating oil retailers and diesel fuel and gasoline resellers. Our commercial customers include federal and state agencies, municipalities, regional transit authorities, large industrial companies, hospitals, and educational institutions. For the years ended December 31, 2013, 2012 and 2011, we sold approximately 1.4 billion, 1.3 billion and 1.2 billion gallons of refined products, respectively. For the years ended December 31, 2013, 2012 and 2011, our refined products segment accounted for 60%, 56% and 65% of our adjusted gross margin, respectively. See Segment Reporting included under Note 16 to our consolidated financial Statements for a presentation of financial results by reportable segment and see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operation Results of Operation for a discussion of financial results by segment.

Our natural gas segment purchases, sells and distributes natural gas to more than 5,000 commercial and industrial customer locations across 10 states in the Northeast and Mid-Atlantic. We purchase the natural gas we sell from natural gas producers and trading companies. For the years ended December 31, 2013, 2012 and 2011, we sold 52.0 Bcf, 49.4 Bcf and 50.7 Bcf of natural gas, respectively. For the years ended December 31, 2013, 2012 and 2011, our natural gas segment accounted for 22%, 19% and 15% of our adjusted gross margin, respectively.

Our materials handling business is a fee-based business and is generally conducted under multi-year agreements. We offload, store and/or prepare for delivery a variety of customer owned products, including asphalt, clay slurry, salt, gypsum, coal, petroleum coke, caustic soda, tallow, pulp and heavy equipment. For the year ended December 31, 2013, we offloaded, stored and/or prepared for delivery, 2.1 million short tons of product and 246.7 million gallons of liquid materials. For the years ended December 31, 2012 and 2011 we offloaded, stored and/or prepared for delivery 2.6 million and 2.4 million short tons of products, and 248.5 million and 265.2 million gallons of liquid materials, respectively. For the years ended December 31, 2013, 2012 and 2011, our materials handling segment accounted for 16%, 23% and 19% of our adjusted gross margin, respectively.

Our other operations consist primarily of coal marketing and distribution and commercial trucking, and for the years ended December 31, 2013, 2012 and 2011, such activities accounted for approximately 2%, 2% and 1% of our adjusted gross margin, respectively.

We take title to the products we sell in our refined products and natural gas segments. We do not take title to any of the products in our materials handling segment. In order to manage our exposure to commodity price fluctuations, we use derivatives and forward contracts to maintain a position that is substantially balanced between product purchases and product sales.

Business Strategies

Our plan is to generate cash flows sufficient to enable us to pay the minimum quarterly distribution on each unit and to increase distributable cash flow per unit by executing the following strategies:

- ***Acquire additional terminals and marketing and distribution businesses***. We intend to grow our asset and customer base by acquiring additional marine and inland terminals (both refined products and materials handling) within and adjacent to the geographic markets we currently serve. We also intend to acquire additional refined products and natural gas marketing businesses that have demonstrated an ability to generate free cash flow and that will enable us to leverage our existing investment in our business and customer service systems to further increase profitability and stability of such cash flow.

Increase our business with existing customers. We intend to increase the net sales and margin we realize from customers we currently serve by expanding the range of products and services we provide and by developing additional ways to address our customers needs for certainty of supply, reduced price commodity risk and high-quality customer service. Our goal is to be alert to our customers needs and be faster and more efficient than our competitors in responding to them.

Limit our exposure to commodity price volatility and credit risk. We take title to the products we sell in our refined products and natural gas segments, while our materials handling business is operated predominantly under fixed-fee, multi-year contracts. We will continue to manage our exposure to commodity prices by seeking to maintain a balanced position in our purchases and sales through the use of derivatives and forward contracts. In addition to managing commodity price volatility, we will continue to manage our counterparty risk by maintaining conservative credit management processes.

Maintain our operational excellence. We intend to maintain our long history of safe, cost-effective operations and environmental stewardship by applying new technologies, investing in the maintenance of our assets and providing training programs for our personnel. We have a Health, Safety and Environmental department primarily devoted to safety matters and reducing operational and environmental risks. We will work diligently to meet or exceed applicable safety and environmental regulations and we will continue to enhance our safety monitoring function as our business grows and operating conditions change.

Refined Products

Overview

The products we sell in our refined products segment can be grouped into three categories: distillates, gasoline and residual fuel oil. Of our total volume sold in our refined products segment in 2013, distillates accounted for approximately 75%, gasoline accounted for approximately 20% and residual fuel oil accounted for approximately 5%.

Distillates. We sell four kinds of distillates: home heating oil (both unbranded and HeatForce®, our proprietary premium heating oil product), diesel fuel (both unbranded and RoadForce®, our proprietary premium diesel fuel), kerosene and jet fuel. In 2013, home heating oil accounted for approximately 66%, diesel fuel accounted for approximately 31%, and other distillates accounted for approximately 3% of the total volume of distillates we sold. Distillate volumes accounted for 75%, 70%, and 73% of our total refined products sales for the years ended December 31, 2013, 2012 and 2011, respectively.

We have the capability at several of our facilities to blend biodiesel with distillates in order to sell bio heating oil and biodiesel. In 2013, biofuel accounted for approximately 3% of the distillate fuel volumes we sold.

Gasoline. We sell unbranded gasoline in qualities that comply with seasonal and geographical requirements. Gasoline volumes accounted for 20%, 24% and 21% of our total refined products sales for the years ended December 31, 2013, 2012 and 2011, respectively.

Residual Fuel Oil. We sell various sulfur grades of residual fuel oil, blended to meet customer requirements, in our market areas. Residual fuel oil volumes accounted for approximately 5%, 6% and 6% of our total refined products sales for the years ended December 31, 2013, 2012 and 2011, respectively.

In 2013, our refined products segment accounted for approximately 92% of our total net sales and 60% of our adjusted gross margin.

Customers, Contracts and Pricing

We sell home heating oil, diesel fuel, kerosene, unbranded gasoline, jet fuel and residual fuel oil to wholesalers, retailers and commercial customers. The majority of these sales are made free on board, or FOB, at the bulk terminal or inland storage facility we own and/or operate or with which we have storage and throughput arrangements, which means the price of products sold includes the cost of delivering such product to that location and any further shipping expenses are borne by the purchaser.

In 2013, we sold home heating oil, including HeatForce®, to approximately 900 wholesale distributors and retailers. These sales are made through Sprague RealTime (our proprietary online sales platform) and under rack agreements based upon our posted price, contracts with index-based pricing provisions and fixed price forward contracts.

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In 2013, we sold diesel fuel, including RoadForce®, to approximately 585 wholesalers and transportation fuel distributors.

In 2013, we sold unbranded gasoline at 18 third-party locations primarily to resellers.

We sell residual fuel oil to approximately 18 commercial and industrial accounts. Sales were made under rack agreements and contracts with index-based pricing provisions.

We also sell home heating oil, diesel fuel, unbranded gasoline and residual fuel oil to public sector entities through competitive bidding processes and to large industrial and commercial customers, including the sale of distillate and residual fuel oil by truck and barge to marine customers.

Our commercial customers include federal and state agencies, municipalities, regional transit authorities, large industrial companies and educational institutions. Most of these sales are made on a delivered basis, whereby we either deliver the product with our own trucks and barges or arrange with third-party haulers to make deliveries on our behalf.

The majority of our refined products sales to commercial customers are made pursuant to a competitive bidding process. Our sales contracts to commercial customers generally are for terms of one to five years. We currently have contracts with the U.S. government as well as with numerous states, municipalities, agencies and educational institutions in the New England and Mid-Atlantic states.

For the year ended December 31, 2013, no customer represented more than 10% of net sales for our refined products segment.

Natural Gas

Overview

We sell natural gas and related delivery services to customers in the states of Massachusetts, New Hampshire, Maine, Rhode Island, Connecticut, New York, New Jersey, Pennsylvania, Ohio and West Virginia. We deliver natural gas to customers through utility interconnections of pipelines and manage interactions with utilities on behalf of our customers. We sell natural gas pursuant to fixed price, floating price and other structured pricing contracts. We utilize physical trading as well as financial and derivative trading both over the counter and through exchanges such as the Intercontinental Exchange Inc. (ICE) and NYMEX, in order to manage our natural gas commodity price risk.

In order to manage our supply commitments to our customers and provide operational flexibility and arbitrage opportunities, we enter into supply contracts, leases for pipeline transportation capacity, leases for storage space and other physical delivery services for various terms. We believe that entering into these types of arrangements provides us with potential opportunities to grow our existing customer relationships and to pursue additional relationships.

For the year ended December 31, 2013, our natural gas segment accounted for approximately 7% of our total net sales, and 22% of our adjusted gross margin.

Customers

Our natural gas customers operate in the industrial and commercial sectors in the Northeast, with the highest concentration in New England and New York. The customers range from large and smaller industrial and commercial consumers. The acquisition of Hesco in 2006 was a precursor to our pursuing a strategy to target the smaller to mid-size commercial and industrial customers as a key growth area. This strategy has led to a significant increase in the number of customers served and unit margins, with sales volumes remaining relatively stable. Examples of customers include industrial users of varying sizes (*e.g.,* pulp and paper, chemicals, pharmaceutical and metals plants) to various commercial customers (*e.g.,* hospitals, universities, apartment buildings and retail stores). The industrial customers have a high concentration of process load to support their manufacturing requirements, with the largest uses by the commercial customers typically for heating, cooling, lighting, cooking and drying.

For the year ended December 31, 2013, no customer represented more than 10% of net sales for our natural gas segment.

Contracts/Pricing

We use various types of contracts for the sale and delivery of natural gas to our customers, with terms ranging from month-to-month to over two years. We provide a wide range of pricing options to our customers, including daily pricing and long-term fixed pricing. For example, we may offer a contract that permits the customer to lock in a basis or location differential relative to the Henry Hub (the most actively traded natural gas delivery location in the United States) and then fix the price at a later date based on the prevailing market pricing. There are various other alternatives such as capped (essentially setting a maximum) pricing or daily pricing based on a differential to a published market index. Due to the commodity price risk associated with uncertain customer usage patterns, we generally avoid transactions that require a single price for all volumes delivered, with the pricing of the non-contractual volumes established based on prevailing market economics.

Materials Handling

Overview

Materials handling is the movement of raw materials and finished goods through our waterfront terminals. We utilize our terminal network to offload, store and/or prepare for delivery a large number of liquid products, bulk and break bulk materials and heavy lift services and provide other handling services to many of the same customers that we supply with refined products.

We are capable of providing numerous types of materials handling services, including ship handling, crane operations, pile building, warehouse operations, scaling and, in some cases, transportation to the final customer. In all cases, we play the role of a distribution agent for our customers. Because the products we handle are generally owned by our customers, we have virtually no working capital requirements, commercial risk or inventory risk. Our materials handling contracts are typically long-term and predominately fee-based.

For the year ended December 31, 2013, our materials handling segment accounted for approximately 1% of our total net sales and 16% of our adjusted gross margin.

Major Types of Materials Handling and Services

The type of materials handling and services we provide can be divided into three major categories:

Liquid. Liquid products are moved to terminals via various types of ocean going vessels and offloaded into terminal tanks via pipelines on the dock of the facility. Examples of liquid materials handled include refined products, asphalt and clay slurry. Liquid handling activities include securing the vessel, attaching product lines from ship pipes to dock product lines, supervising discharge into tanks, measuring tank quantities, storing product, loading product into authorized trucks or railcars and transporting product to its final destination. In some cases the products need to remain heated in storage to be able to flow at ambient temperatures.

Bulk. Bulk materials are normally some type of aggregate materials moved in large vessels configured with multiple holds that store products on ships in piles with no other type of packaging. Examples of bulk material

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include salt, petroleum coke, gypsum, cement and coal. These vessels are normally offloaded via cranes that either reside on the vessel or on the dock of the terminal. In a typical discharge the services performed include: securing the vessel to the dock, operating the vessel cranes, transferring products to trucks via large dock hoppers, transporting the materials to a holding pad, building materials up into large storage piles, covering the piles with protective tarps, storing the product, loading the product into trucks or railcars, scaling the loaded trucks and sometimes transporting the product to its final destination.

Break bulk. Break bulk materials are shipped in less than bulk quantities normally with some type of secondary packaging. Examples of break bulk materials include one ton sacks of raw materials, pallets of stones, bales of raw wood pulp and rolls of paper. Another subcategory of break bulk materials is large construction project cargo such as windmill components, often referred to as heavy lift. Break bulk handling activities include securing vessels, unloading or loading vessels either with cranes or specialty fork trucks, transferring products into warehouses or onto pads for storage, reloading products onto trucks or railcars and sometimes transporting products to their final destinations.

Customers

Our materials handling operations can service multiple customer types during any single operation, including: the ocean shippers, multiple logistics firms, trucking firms and the materials supplier or consumer. The materials we handle normally fall into two major categories. The first category involves raw materials or finished goods shipped by water into local markets to support local production, manufacturing or construction firms. Examples of these products include asphalt for road construction, gypsum rock for drywall manufacturing, road salt for local road treatment, petroleum coke or utility fuels for energy demand and clay slurry for finished paper treatment. The second category of materials we handle are materials manufactured locally for export via vessel to other countries. These materials include Maine hardwood, wood pulp for paper manufacture in Asia or Europe and tallow for biodiesel production in Europe.

For the year ended December 31, 2013, we had four customers who represented an aggregate 47% of net sales for our materials handling segment, although none of the customers represented more than 1% of our total net sales.

Contracts/Pricing

The typical contract term for our materials handling services varies depending on the frequency and type of service. For bulk and liquid services, the commodity is normally a raw materials input for industrial production (wood pulp) or construction of roads (asphalt) or wallboard (gypsum rock). As such, the demand is more ratable and the customer is normally in need of guaranteed space within a terminal. These customers normally enter into term contracts that can range from one to 20 years depending on the relative importance of the material to their production and the amount of any capital infrastructure that we need to develop for such customers. As of December 31, 2013, the weighted-average life of our materials handling contracts was approximately eight years, with a weighted-average remaining life of approximately five years, each based on gross margin attributable to these contracts. Generally, our customers will pay for terminal improvements for specialty handling systems such as a clay slurry screening plant, and we will pay for more generic handling systems such as storage pads.

For container and break bulk services, it is more typical for the user of that material to contract on an individual shipment basis. For example, a typical pulp merchant may choose to sell its pulp domestically or to users in Europe or Asia depending on the highest delivered value it can yield. As such, its choice of delivery mode and terminal will be driven by the location of its final customer. Therefore, we normally maintain a published rate for most generic services. Those rates are subject to change depending on market conditions.

Other Operations

Our other operations segment includes the marketing and distribution of coal that is conducted in our South Portland and Portland, Maine terminals. For the year ended December 31, 2013, our other operations segment accounted for less than 1% of our total net sales and 2% of our adjusted gross margin.

Commodity Risk Management

Because we take title to the refined products and natural gas that we sell, we are exposed to commodity risk. Our materials handling business is a fee-based business and, accordingly, our operations in that business segment have only limited exposure to commodity risk. Commodity risk is the risk of market fluctuations in the price of commodities such as refined products and natural gas. We endeavor to limit unfavorable commodity price risk in connection with our daily operations. Generally, as we purchase and/or store refined products, we reduce commodity risk through hedging by selling futures contracts on regulated exchanges or using other derivatives, and then close out the related hedge as we sell the product for physical delivery to third parties. Products are generally purchased and sold at spot prices, fixed prices or indexed prices. While we use these transactions to seek to maintain a position that is substantially balanced between purchased volumes and sales volumes through regulated exchanges or derivatives, we may experience net unbalanced positions for short periods of time as a result of variances in daily sales and transportation and delivery schedules, as well as logistical issues associated with inclement weather conditions or infrastructure disruptions. Our general policy is to not hold refined products futures contracts or other derivative products and instruments for the sole purpose of speculating on price changes. While our policies are designed to limit market risk, some degree of exposure to unforeseen fluctuations in market conditions remains.

Our operating results are sensitive to a number of factors. Such factors include commodity location, grades of product, individual customer demand for grades or location of product, localized market price structures, availability of transportation facilities, daily delivery volumes that vary from expected quantities and timing and costs to deliver the commodity to the customer. The term basis risk is used to describe the inherent market price risk created when a commodity of certain grade or location is purchased, sold or exchanged as compared to a purchase, sale or exchange of that commodity at a different time or place, including, without limitation, transportation costs and timing differentials. We attempt to reduce our exposure to basis risk by grouping our purchase and sale activities by geographical region and commodity quality in order to stay balanced within such designated region.

With respect to the pricing of commodities, we enter into derivative positions to limit or hedge the impact of market fluctuations on our purchase and forward fixed price sales of refined products. Any hedge ineffectiveness is reflected in our results of operations.

With respect to refined products, we primarily use a combination of futures contracts, over-the-counter swaps and forward purchases and sales to hedge our price risk. For light oils (gasoline and distillates), we primarily utilize the actively traded futures contracts on the regulated NYMEX as the derivatives to hedge our positions. Heavy oils are typically hedged with fixed-for-floating price residual fuel oil swaps contracts, which are either balanced by offsetting positions or financially settled (meaning that these swaps do not include a delivery option).

With respect to natural gas, we generally use fixed-for-floating price swaps contracts that trade on the ICE for hedging. As an alternative, we may use NYMEX natural gas futures for such purposes. In addition, we use natural gas basis swaps to hedge our basis risk.

For both refined products and natural gas, if we trade in any derivatives that are not cleared on an exchange, we strive to enter into derivative agreements with counterparties that we believe have a strong credit profile and/or provide us with significant trade credit to limit counterparty risk and margin requirements. We monitor processes and procedures to prevent unauthorized trading by our personnel and to maintain substantial balance between purchases and sales or future delivery obligations.

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Storage and Distribution Services

Marine terminals and inland storage facilities play a key role in the distribution of product to our customers. We own and/or operate a network of 15 refined products and materials handling terminals strategically located throughout the Northeast United States that have a combined storage capacity of approximately 9.2 million barrels for refined products and other liquid materials, as well as approximately 1.5 million square feet of materials handling capacity. We also have an aggregate of approximately 1.4 million barrels of additional storage capacity attributable to 41 storage tanks not currently in service. These tanks are not necessary for the operation of our business at current levels. In the event that such additional capacity were desired, additional time and capital would be required to bring any of such storage tanks into service. Furthermore, we have access to more than 60 third-party terminals in the Northeast through which we sell or distribute refined products pursuant to rack, exchange and throughput agreements.

The marine terminals and inland storage facilities from which we distribute product are supplied by ship, barge, truck, pipeline or rail. The inland storage facilities, which we use exclusively to store distillates, are supplied with product delivered by truck from marine and other bulk terminals. Our customers receive product from our network of marine terminals and inland storage facilities via truck, barge, rail or pipeline.

Our marine terminals consist of multiple storage tanks and automated truck loading equipment. These automated systems monitor terminal access, volumetric allocations, credit control and carrier certification through the identification of customers. In addition, some of the marine and inland terminals at which we market are equipped with truck loading racks capable of providing automated blending and additive packages that meet our customers specific requirements. Many of our marine and inland terminals operate 24 hours per day.

Throughput arrangements allow storage of product at terminals owned by others. These arrangements permit our customers to load product at third-party terminals while we pay the owners of these terminals fees for services rendered in connection with the receipt, storage and handling of such product. Payments we make to the terminal owners may be fixed or based upon the volume of product that is delivered and sold at the terminal.

Exchange agreements allow our customers to take delivery of product at a terminal or facility that is not owned or leased by us. An exchange is a contractual agreement pursuant to which the parties exchange product at their respective terminals or facilities. For example, we (or our customers) receive product that is owned by the other party from such party s facility or terminal and we deliver the same volume of product to such party (or to such party s customers) out of one of the terminals in our terminal network. Generally, both parties to an exchange transaction pay a handling fee (similar to a throughput fee) and often one party also pays a location differential that covers any excess transportation costs incurred by the other party in supplying product to the location at which the first party receives product. Other differentials that may occur in exchanges (and result in additional payments) include product value differentials and timing differentials.

Our Terminals

We own and/or operate a network of 15 refined products and material handling terminals located along the coast of the Northeastern United States from New York to Maine. We own all of these facilities, with the exception of our terminal located in Quincy, Massachusetts (which is under a long-term lease), our Portland, Maine terminal (where we lease the real estate and two storage buildings under a long-term lease and own the balance of the assets) and our New Bedford, Massachusetts terminal (where we lease the operating assets and real estate from Sprague Massachusetts Properties LLC, a wholly owned subsidiary of Sprague Holdings). We also lease a tank with storage capacity of approximately 136,000 barrels from a subsidiary of Dominion Resources, Inc. at our Providence, Rhode Island terminal. Our facilities are equipped to provide terminalling, storage and distribution of both solid and liquid products to serve our refined products and materials handling businesses. Each facility has capabilities that are unique to the local markets served. A majority of facilities additionally have demonstrated flexibility in their ability to handle liquid, dry bulk and break bulk products at the same terminal and in most cases across the same dock. This capability has offered us valuable flexibility to fully utilize each asset to meet a variety of fuel demands and third-party cargo handling demands as customer requirements have changed over the years.

We operate seven terminals that are capable of handling both liquid petroleum products and providing third-party materials handling services. Five terminals exclusively handle liquid petroleum products and three terminals are dedicated exclusively to materials handling services. Total liquid storage capacity throughout our owned and/or operated terminals is approximately 9.2 million barrels (which excludes approximately 1.4 million barrels of storage capacity not currently in service). Inside warehouse capacity at our owned and/or operated terminals totals approximately 316,000 square feet with approximately 1.2 million square feet of outside laydown space available.

For a more detailed description of our terminals, please read Item 2. Properties.

Competition

We encounter varying degrees of competition based on product type and geographic location in the marketing of our refined products. In our Northeast market, we compete in various product lines and for a range of customer types. The principal methods of competition in our refined products operations are pricing, services offerings to customers, credit support and certainty of supply. Our competitors include terminal companies, major integrated oil companies and their marketing affiliates and independent marketers of varying sizes, financial resources and experience. We believe that our being one of the largest independent wholesale distributors of refined products in the Northeast (based on aggregate terminal capacity), our ownership of various marine-based terminals and our reputation for reliability and strong customer service provide us with a competitive advantage in marketing refined products in the areas in which we operate.

Competitors of our natural gas sales operations generally include natural gas suppliers and distributors of varying sizes, financial resources and experience, including producers, pipeline companies, utilities and independent marketers. The principal methods of competition in our natural gas operations are in obtaining supply, pricing optionality for customers and effective support services, such as scheduling and risk management. We believe that our sizeable market presence and strong customer service and offerings provide us with a competitive advantage in marketing natural gas in the areas in which we operate.

In our materials handling operations, we primarily compete with public and private port operators. Although customer decisions are substantially based on location, additional points of competition include types of services provided and pricing. We believe that our ability to provide materials handling services at a number of our refined products terminals and our demonstrated ability to handle a wide range of products provides us a competitive advantage in competing for products-related handling services in the areas in which we operate.

Seasonality

Demand for natural gas and some refined products, specifically home heating oil and residual fuel oil for space heating purposes, is generally higher during the period of November through March than during the period of April through October. Therefore, our results of operations for the first and fourth calendar quarters are generally better than for the second and third calendar quarters. For example, over the 36-month period ended December 31, 2013, we generated an average of approximately 69% of our total home heating oil and residual fuel oil net sales during the months of November through March.

Employees

We do not have any employees. Our general partner employs more than 400 full-time employees who support our operations and also employs some part-time hourly workers who are on call during peak periods. Approximately 43 of the full-time employees are covered by collective bargaining agreements.

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Item 1A. Risk Factors

Common units are inherently different from the 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 a similar business.

If any of the following risks were actually to occur, our business, financial condition, results of operations and ability to pay distributions to our unitholders could be materially adversely affected. Additional risks and uncertainties not currently known to us or that we currently consider to be immaterial may also materially adversely affect our business, financial condition, results of operations and ability to pay distributions to our unitholders.

Risks Related to Our Business

We may not have sufficient distributable cash flow following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements to our general partner and its affiliates, to enable us to pay the minimum quarterly distribution to our unitholders.

In order to pay the minimum quarterly distribution of $0.4125 per unit per quarter, or $1.65 per unit on an annualized basis, we will require distributable cash flow of approximately $8.3 million per quarter, or approximately $33.2 million per year, based on the number of common and subordinated units currently outstanding. We may not have sufficient distributable cash flow each quarter to enable us to pay the minimum quarterly distribution. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- Competition from other companies that sell refined products, natural gas and/or renewable fuels in the Northeast;
- Competition from other companies in the materials handling business;
- Demand for refined products, natural gas and our materials handling services in the markets we serve;
- Absolute price levels, as well as the volatility of prices, of refined products and natural gas in both the spot and futures markets;
- Seasonal variation in temperatures, which affects demand for natural gas and refined products such as home heating oil and residual fuel oil to the extent that it is used for space heating; and
- Prevailing economic conditions.

In addition, the actual amount of distributable cash flow that we distribute will depend on other factors such as:

- The level of maintenance capital expenditures we make;

The level of our operating and general and administrative expenses, including reimbursements to our general partner and certain of its affiliates for services provided to us;

The restrictions contained in our credit agreement, including borrowing base limitations and limitations on distributions;

Our debt service requirements;

The cost of acquisitions we make, if any;

Fluctuations in our working capital needs;

Our ability to access capital markets and to borrow under our credit agreement to make distributions to our unitholders; and

The amount of cash reserves established by our general partner, if any.

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Our distributable cash flow depends primarily on our cash flow and not solely on profitability, which may prevent us from making cash distributions during periods when we record net income.

Our distributable cash flow depends primarily on our cash flow, and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we record losses and may not make cash distributions during periods when we record net income.

Our business is seasonal and generally our financial results are lower in the second and third quarters of the calendar year, which may result in our need to borrow money in order to make quarterly distributions to our unitholders during these quarters.

Demand for natural gas and some refined products, specifically home heating oil and residual fuel oil for space heating purposes, is generally higher during the period of November through March than during the period of April through October. Therefore, our results of operations for the first and fourth calendar quarters are generally better than for the second and third calendar quarters. For example, over the 36-month period ended December 31, 2013, we generated an average of approximately 69% of our total home heating oil and residual fuel oil net sales during the months of November through March. With reduced cash flow during the second and third calendar quarters, we may be required to borrow money in order to pay the minimum quarterly distribution to our unitholders. Any restrictions on our ability to borrow money could restrict our ability to make quarterly distributions to our unitholders.

A significant decrease in demand for refined products, natural gas or our materials handling services in the areas we serve would adversely affect our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders.

A significant decrease in demand for refined products, natural gas or our materials handling services in the areas that we serve would significantly reduce our net sales and, therefore, adversely affect our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders. Factors that could lead to a decrease in market demand for refined products or natural gas include:

- Recession or other adverse economic conditions;
- High prices caused by an increase in the market price of refined products, higher fuel taxes or other governmental or regulatory actions that increase, directly or indirectly, the cost of gasoline or other refined products or natural gas;
- Increased conservation, technological advances and the availability of alternative energy, whether as a result of industry changes, governmental or regulatory actions or otherwise; and
- Conversion from consumption of home heating oil or residual fuel oil to natural gas.

Factors that could lead to a decrease in demand for our materials handling services include weakness in the housing and construction industries and the economy generally.

Certain of our operating costs and expenses are fixed and do not vary with the volumes we store, distribute and sell. These costs and expenses may not decrease ratably, or at all, should we experience a reduction in our volumes stored, distributed and sold. As a result, we may experience declines in our operating margin if our volumes decrease.

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Our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders are influenced by changes in demand for, and therefore indirectly by changes in the prices of, refined products and natural gas, which could adversely affect our profit margins, our customers and suppliers financial condition, contract performance, trade credit and the amount and cost of our borrowing under our credit agreement.

Financial and operating results from our purchasing, storing, terminalling and selling operations are influenced by price volatility in the markets for refined products and natural gas. When prices for refined products and natural gas rise, some of our customers may have insufficient credit to purchase supply from us at their historical purchase volumes, and their customers, in turn, may adopt conservation measures which reduce consumption, thereby reducing demand for product. Furthermore, when prices increase rapidly and dramatically, we may be unable to promptly pass our additional costs to our customers, resulting in lower margins for a period of time before margins expand to cover the incremental costs. Significant increases in the costs of refined products can materially increase our costs to carry inventory. We use the working capital facility in our credit agreement, which limits the amounts that we can borrow, as our primary source of financing our working capital requirements. Lastly, higher prices for refined products or natural gas may (1) diminish our access to trade credit support or cause it to become more expensive and (2) decrease the amount of borrowings available for working capital as a result of total available commitments, borrowing base limitations and advance rates thereunder.

In addition, when prices for refined products or natural gas decline, the likelihood of nonperformance by our customers on forward contracts may be increased as they and/or their customers may choose not to honor their contracts and instead purchase refined products or natural gas at the then lower spot or retail market price.

Restrictions in our credit agreement could adversely affect our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders as well as the value of our common units.

We will be dependent upon the earnings and cash flow generated by our operations in order to meet our debt service obligations and to allow us to make cash distributions to our unitholders. The operating and financial restrictions and covenants in our credit agreement and any future financing agreements could restrict our ability to finance future operations or capital needs or to expand or pursue our business, which may, in turn, adversely affect our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders. For example, our credit agreement restricts our ability to, among other things:

- Make cash distributions;
- Incur indebtedness;
- Create liens;
- Make investments;
- Engage in transactions with affiliates;

Make any material change to the nature of our business;

Dispose of assets; and

Merge with another company or sell all or substantially all of our assets.

Furthermore, our credit agreement contains covenants requiring us to maintain certain financial ratios.

The provisions of our credit agreement may affect our ability to obtain future financing for and pursue attractive business opportunities and our flexibility in planning for, and reacting to, changes in business conditions. In addition, a failure to comply with the provisions of our credit agreement could result in an event of default which could enable our lenders, subject to the terms and conditions of our credit agreement, to declare the outstanding principal of that debt, together with accrued interest, to be immediately due and payable. If we were unable to repay the accelerated amounts, our lenders could proceed against the collateral granted to them to secure such debt. If the payment of our debt is accelerated, defaults under our other debt instruments, if any, may be triggered and our assets may be insufficient to repay such debt in full, and the holders of our units could experience a partial or total loss of their investment. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources.

Debt we incur in the future may limit our flexibility to obtain financing and to pursue other business opportunities.

Our future level of debt could have important consequences to us, including the following:

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

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

Warmer weather conditions during winter could adversely affect our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders.

Weather conditions during winter have an impact on the demand for both home heating oil and residual fuel oil. Because we supply distributors whose customers depend on home heating oil and residual fuel oil during the winter, warmer-than-normal temperatures during the first and fourth calendar quarters in one or more regions in which we operate can decrease the total volume we sell and the gross margin realized on those sales and, consequently, our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders.

Derivatives legislation could have an adverse impact on our ability to use derivatives to reduce the effect of commodity price risk, interest rate risk, and other risks associated with our business and could have an adverse impact on the cost of our hedging activities.

We use over-the-counter (OTC) derivatives products to hedge commodity risks and interest rate risks.

On July 21, 2010 comprehensive financial reform legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act), was enacted that changes federal oversight and regulation of the over-the-counter derivatives market and entities, including us, that participate in that market. The Dodd-Frank Act requires the Commodity Futures Trading Commission (CFTC), the SEC and other regulators to promulgate rules and regulations implementing the new legislation.

In its rulemaking under the Dodd-Frank Act the CFTC has issued final regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions would be exempt from these position limits. The position limits rule was vacated by the United States District Court for the District of Colombia in September of 2012 although the CFTC appealed the District Court s decision.

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The CFTC also has finalized other regulations, including critical rulemakings on the definition of swap , security-based swap , swap dealer and major swap participant . The Dodd-Frank Act and CFTC rules also may require us in connection with certain derivatives activities to comply with clearing and trade-execution requirements (or take steps to qualify for an exemption to such requirements). In addition new regulations may require us to comply with margin requirements although these regulations are not finalized and their application to us is uncertain at this time. Other regulations also remain to be finalized, and the CFTC has delayed the compliance dates for various regulations already finalized. As a result it is not possible at this time to predict with certainty the full effects of the Dodd-Frank Act and CFTC rules on us and the timing of such effects. The Dodd-Frank Act also may require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty.

The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts (including from swap recordkeeping and reporting requirements and through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable.

Our risk management policies, processes and procedures cannot eliminate all commodity price risk or basis risk, which could adversely affect our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders. In addition, any noncompliance with our risk management policies, processes and procedures could result in significant financial losses.

While our risk management policies, processes and procedures are designed to limit commodity price risk, some degree of exposure to unforeseen fluctuations in market conditions remains. For example, we change our hedged position daily in response to movements in our inventory. If we overestimate or underestimate our sales from inventory, we may be unhedged for the amount of the overestimate or underestimate.

In general, basis risk describes the inherent market price risk created when a commodity of certain grade or location is purchased, sold or exchanged as compared to a purchase, sale or exchange of a like commodity at a different time or place. Basis may reflect price differentiation associated with different time periods, qualities or grades, or locations and is typically calculated based on the price difference between the cash or spot price of a commodity and the prompt month futures or swaps contract price of the most comparable commodity. For example, if NYMEX heating oil, which is based on New York Harbor delivery, was used to hedge our commodity risk for heating oil purchases, we could have location basis risk if the deliveries were made in a different location such as in Boston. An example of quality or grade basis risk would be the use of heating oil contracts to hedge diesel fuel. The potential exposure from basis risk is in addition to any impact that market pricing structure may have on our results. Basis risk cannot be entirely eliminated and basis exposure can adversely affect our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders.

We monitor policies, processes and procedures designed to prevent unauthorized trading and to maintain substantial balance between purchases and sales or future delivery obligations. We can provide no assurance, however, that these steps will detect and/or prevent all violations of such risk management policies, processes and procedures, particularly if deception or other intentional misconduct is involved.

We are exposed to risks of loss in the event of nonperformance by our customers, suppliers and counterparties.

Some of our customers, suppliers and counterparties may be highly leveraged and subject to their own operating and regulatory risks. A tightening of credit in the financial markets or an increase in interest rates may make it more difficult for our customers, suppliers and counterparties to obtain financing and, depending on the degree to which it occurs, there may be a material increase in the nonpayment or other nonperformance by our customers, suppliers and counterparties. Even if our credit review and analysis mechanisms work properly, we may experience financial losses in our dealings with these third parties. A material increase in the nonpayment or other nonperformance by our customers, suppliers and/or counterparties could adversely affect our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders.

Additionally, our access to trade credit support could diminish or become more expensive. Our ability to continue to receive sufficient trade credit on commercially acceptable terms could be adversely affected by, among other things, fluctuations in refined product, natural gas and renewable fuel prices or disruptions in the credit markets.

We are exposed to performance risk in our supply chain.

We rely upon our suppliers to timely produce the volumes and types of refined products for which they contract with us. In the event one or more of our suppliers does not perform in accordance with its contractual obligations, we may be required to purchase product on the open market to satisfy forward contracts we have entered into with our customers in reliance upon such supply arrangements. We purchase refined products from a variety of suppliers under term contracts and on the spot market. In times of extreme market demand, we may be unable to satisfy our supply requirements. Furthermore, a portion of our supply comes from other countries, which could be disrupted by political events. In the event such supply becomes scarce, whether as a result of political events, natural disaster, logistical issues associated with delivery schedules or otherwise, we may not be able to satisfy our supply requirements. If any of these events were to occur, we may be required to pay more for product that we purchase on the open market, which could result in financial losses and adversely affect our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders.

Some of our competitors have capital resources many times greater than ours and control greater supplies of refined products and natural gas. Competitors able to supply our customers with those products and services at a lower price could adversely affect our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders.

Our competitors include terminal companies, major integrated oil companies and their marketing affiliates and independent marketers of varying size, financial resources and experience. Some of our competitors are substantially larger than us, have capital resources many times greater than ours, control greater supplies of refined products and natural gas than us and/or control substantially greater storage capacity than us. If we are unable to compete effectively, we may lose existing customers or fail to acquire new customers, which could have a material adverse effect on our business, financial condition, results of operations and distributable cash flow. For example, if a competitor attempts to increase market share by reducing prices or offering alternative energy sources, our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders could be adversely affected. We may not be able to compete successfully with these companies.

Some of our home heating oil and residual fuel oil volumes are subject to customers switching or converting to natural gas, which could result in loss of customers and, in turn, could have an adverse effect on our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders.

Our home heating oil and residual fuel oil businesses compete for customers with suppliers of natural gas. During a period of increasing home heating oil prices relative to natural gas prices, home heating oil users may convert to natural gas. Similarly, during a period of increasing residual fuel oil prices relative to natural gas prices, customers who have the ability to switch from residual fuel oil to natural gas (dual-fuel using customers), may switch and other end users may convert to natural gas.

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Such switching and conversions could reduce our sales of home heating oil and residual fuel oil and could adversely affect our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders.

Energy efficiency, new technology and alternative energy sources could reduce demand for our products and adversely affect our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders.

Increased conservation, technological advances, including installation of improved insulation and the development of more efficient furnaces and other heating devices, and the availability of alternative energy sources have adversely affected the demand for some of our products, particularly home heating oil and residual fuel oil. Future conservation measures, technological advances in heating, conservation, energy generation or other devices, and increased availability and use of alternative energy sources, including as a result of government regulation, might reduce demand and adversely affect our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders.

A principal focus of our business strategy is to grow and expand our business through acquisitions. If we do not make acquisitions on economically acceptable terms, our future growth may be limited and any acquisitions we make may reduce, rather than increase, our cash generated from operations on a per unit basis.

A principal focus of our business strategy is to grow and expand our business through acquisitions. Our ability to grow depends, in part, on our ability to make acquisitions that result in an increase in the cash generated per unit from operations. If we are unable to make accretive acquisitions, either because we are (1) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them, (2) unable to obtain financing for these acquisitions on economically acceptable terms or (3) outbid by competitors, then our future growth and ability to increase distributions will be limited. Furthermore, even if we do make acquisitions that we believe will be accretive, such acquisitions may nevertheless result in a decrease in the cash generated from operations per unit.

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

- Mistaken assumptions about volumes, cash flows, net sales and costs, including synergies;
- An inability to successfully integrate the businesses we acquire;
- An inability to hire, train or retain qualified personnel to manage and operate our newly acquired assets;
- The assumption of unknown liabilities;
- Limitations on rights to indemnity from the seller;
- Mistaken assumptions about the overall costs of equity or debt used to finance an acquisition;

The diversion of management s and employees attention from other business concerns;

Unforeseen difficulties operating in new product areas or new geographic areas; and

Customer or key employee losses at the acquired businesses.

A portion of our net sales is generated under contracts that must be renegotiated or replaced periodically. If we are unable to successfully renegotiate or replace these contracts, our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders could be adversely affected.

Most of our contracts with our refined products customers are for a single season or on a spot basis, while most of our contracts with our natural gas customers are for a term of one year or less. As these contracts and our materials handling contracts expire from time to time, they must be renegotiated or replaced. We may be unable to renegotiate or replace these contracts when they expire, and the terms of any renegotiated contracts may not be as favorable as the contracts they replace. Whether these contracts are successfully renegotiated or replaced is often subject to factors beyond our control. Such factors include fluctuations in refined product and natural gas prices, counterparty ability to pay for or accept the contracted volumes and a competitive marketplace for the services we offer. While our materials handling contracts are generally long-term, they are also subject to periodic renegotiation or replacement. If we cannot successfully renegotiate or replace any of our contracts, or if we renegotiate or replace them on less favorable terms, net sales and margins from these contracts could decline and our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders could be adversely affected.

Due to our lack of geographic diversification, adverse developments in the terminals we use or in our operating areas would adversely affect our results of operations and distributable cash flow.

We rely primarily on sales generated from products distributed from the terminals we own or control or to which we have access. Furthermore, substantially all of our operations are located in the Northeast. Due to our lack of geographic diversification, an adverse development in the businesses or areas in which we operate, including adverse developments due to catastrophic events or weather and decreases in demand for refined products, could have a significantly greater impact on our results of operations and distributable cash flow than if we operated in more diverse locations.

Our operations are subject to operational hazards and unforeseen interruptions for which we may not be able to maintain adequate insurance coverage.

We are not fully insured against all risks incident to our business. Our operations are subject to many operational hazards and unforeseen interruptions inherent in our business, including:

- Damage to storage facilities and other assets caused by tornadoes, hurricanes, floods, earthquakes, fires, explosions, extreme weather conditions and other natural disasters;
- Acts or threats of terrorism;
- Unanticipated equipment and mechanical failures at our facilities;
- Disruptions in supply infrastructure or logistics and other events beyond our control;
- Operator error; and
- Environmental pollution or other environmental issues.

If any of these events were to occur, we could incur substantial losses because of personal injury or loss of life, severe damage to and destruction of property and equipment, and pollution or other environmental damage resulting in curtailment or suspension of our related operations.

We may be unable to maintain or obtain insurance of the type and amount we believe to be appropriate for our business at reasonable rates or at all. As a result of market conditions, premiums and deductibles for certain of our insurance policies have increased over the past four years and could escalate further. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage. Certain types of risks, such as fines and penalties, or remediation or damages claims from environmental pollution, are either not covered by insurance or applicable insurance may be unavailable for particular claims based on exclusions or limitations in the policies. If we were to incur a significant liability for which we were not fully insured, it could adversely affect our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders.

Our terminalling and materials handling operations are subject to federal, state and local laws and regulations relating to environmental protection and operational safety that require us to incur substantial costs and that may become more stringent over time.

The risk of substantial environmental costs and liabilities is inherent in terminalling and materials handling operations, and we may incur substantial environmental costs and liabilities. In particular, our terminalling operations involve the receipt, storage and redelivery of refined products and are subject to stringent federal, state and local laws and regulations regulating product quality specifications and other environmental matters including the discharge of materials into the environment, or otherwise relating to the protection of the environment, operational safety and related matters. Compliance with these laws and regulations increases our overall cost of business, including our capital costs to maintain and upgrade equipment and facilities. Further, we may incur increased costs because of stricter pollution control requirements or liabilities resulting from noncompliance with required operating or other regulatory permits. We utilize a number of terminals that are owned and operated by third parties who are also subject to these stringent federal, state and local environmental laws in their operations. Compliance with these requirements could increase the cost of doing business with these facilities and there can be no assurances as to the timing and type of such changes or what the ultimate costs might be. Moreover, the failure to comply with these requirements can expose our operations to fines, penalties and injunctive relief.

The risks of spills and releases and the associated liabilities for investigation, remediation and third-party claims, if any, are inherent in terminalling operations, and the liabilities that we incur may be substantial.

Our operation of refined products terminals and storage facilities is inherently subject to the risks of spills, discharges or other inadvertent releases of petroleum or other hazardous substances. If any of these events have previously occurred or occur in the future, whether in connection with any of our storage facilities or terminals, any other facility to which we send or have sent wastes or by-products for treatment or disposal or on any property which we own or have owned, we could be liable for all costs, jointly and severally, and administrative, civil and criminal penalties associated with the investigation and remediation of such facilities under federal, state and local environmental laws or the common law. We may also be held liable for damages to natural resources, personal injury or property damage claims from third parties, including the owners of properties located near our terminals and those with whom we do business, alleging contamination from spills or releases from our facilities or operations. Even if we are insured against certain or all of such risks, we may be responsible for all such costs to the extent our insurers or indemnitors do not fulfill their obligations to us. The payment of such costs or penalties could be significant and have a material adverse effect on our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders.

Increased regulation of greenhouse gas emissions could result in increased operating costs and reduced demand for refined products as a fuel source, which could in turn reduce demand for our products and adversely affect our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders.

Combustion of fossil fuels, such as the refined products we sell, results in the emission of carbon dioxide into the atmosphere. On December 15, 2009, the Environmental Protection Agency, or the EPA, published its findings that emissions of carbon dioxide and other greenhouse gases present an endangerment to public 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, and the EPA has begun to regulate greenhouse gases, or GHG, emissions pursuant to the Clean Air Act. Many states and regions have adopted GHG initiatives and it is possible that federal legislation could be adopted in the future to restrict GHG emissions.

There are many regulatory approaches currently in effect or being considered to address greenhouse gases, including possible future U.S. treaty commitments, new federal or state legislation that may impose a carbon emissions tax or establish a cap-and-trade program and regulation by the EPA. Future international, federal and state initiatives to control carbon dioxide emissions could result in increased costs associated with refined

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products consumption, such as costs to install additional controls to reduce carbon dioxide emissions or costs to purchase emissions reduction credits to comply with future emissions trading programs. Such increased costs could result in reduced demand for refined products and some customers switching to alternative sources of fuel which could have a material adverse effect on our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders.

We are subject to federal, state and local laws and regulations that govern the product quality specifications of the refined products we purchase, store, transport and sell.

Various federal, state and local government agencies have the authority to prescribe specific product quality specifications to the sale of commodities. Changes in product quality specifications, such as reduced sulfur content in refined products, or other more stringent requirements for fuels, could reduce our ability to procure product and require us to incur additional handling costs and capital expenditures. If we are unable to procure product or recover these costs through increased sales, we may not be able to meet our financial obligations.

We depend on unionized labor for our operations in Lawrence, Mt. Vernon and Albany, New York and in Providence, Rhode Island. Work stoppages or labor disturbances at these facilities could disrupt our business.

Work stoppages or labor disturbances by our unionized labor force could have an adverse effect on our financial condition, results of operations and distributable cash flow. In addition, employees who are not currently represented by labor unions may seek representation in the future, and renegotiation of collective bargaining agreements may result in agreements with terms that are less favorable to us than our current agreements.

We rely on our information technology systems to manage numerous aspects of our business, and a disruption of these systems could adversely affect our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders.

We depend on our information technology, or IT, systems to manage numerous aspects of our business and to provide analytical information to management. Our IT systems are an essential component of our business and growth strategies, and a serious disruption to our IT systems could limit our ability to manage and operate our business efficiently. These systems are vulnerable to, among other things, damage and interruption from power loss or natural disasters, computer system and network failures, loss of telecommunication services, physical and electronic loss of data, security breaches and computer viruses. We employ back-up IT facilities and have disaster recovery plans; however, these safeguards may not entirely prevent delays or other complications that could arise from an IT systems failure, a natural disaster or a security breach. Significant failure or interruption in our IT systems could cause our business and competitive position to suffer and damage our reputation, which would adversely affect our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders.

If we fail to develop or maintain an effective system of internal controls, we may not be able to report our financial results accurately or prevent fraud, which could adversely affect our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders.

Prior to our IPO, we had not been required to file reports with the SEC. In connection with the completion of our IPO, we became subject to the public reporting requirements of the Securities Exchange Act of 1934, as amended, or the Exchange Act. We prepare our consolidated financial statements in accordance with GAAP, but our internal accounting controls may not currently meet all standards applicable to companies with publicly traded securities. Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and to operate successfully as a publicly traded partnership. Our efforts to develop and maintain our internal controls may not be successful, and we may be unable to maintain effective controls over our financial

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processes and reporting in the future or comply with our obligations under Section 404 of the Sarbanes-Oxley Act of 2002, which we refer to as Section 404. For example, Section 404 will require us, among other things, to annually review and report on, and our independent registered public accounting firm to attest to, the effectiveness of our internal controls over financial reporting.

We must comply with Section 404 for our fiscal year ending December 31, 2014. Any failure to develop, implement or maintain effective internal controls, or to improve our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Given the difficulties inherent in the design and operation of internal controls over financial reporting, we can provide no assurance as to our, or our independent registered public accounting firm s conclusions about the effectiveness of our internal controls, and we may incur significant costs in our efforts to comply with Section 404. Ineffective internal controls will subject us to regulatory scrutiny and a loss of confidence in our reported financial information, which could adversely affect our business, financial condition, results of operations and ability to make quarterly distributions to our unitholders.

Risks Inherent in an Investment in Us

It is our business strategy to distribute most of our distributable cash flow, which could limit our ability to grow and make acquisitions.

We expect that we will distribute most of our distributable cash flow to our unitholders and will rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund our acquisitions and expansion capital expenditures. As a result, to the extent we are unable to finance growth externally, our cash distribution policy will significantly impair our ability to grow. In addition, because we distribute most of our distributable cash flow, our growth may not be as fast as that of businesses that reinvest their available cash to expand ongoing operations. To the extent we issue additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk that we will be unable to maintain or increase our per unit distribution level. There are no limitations in our partnership agreement or our credit agreement on our ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt to finance our growth strategy would result in increased interest expense, which, in turn, may impact the cash that we have available to distribute to our unitholders.

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

Axel Johnson, through its ownership of Sprague Holdings, indirectly owns a 57.8% limited partner interest in us and indirectly owns and controls our general partner. Although our general partner has a fiduciary duty to manage us in good faith, 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 owner, Sprague Holdings, which is a wholly owned subsidiary of Axel Johnson. Furthermore, certain directors and officers of our general partner are directors and/or officers of affiliates of our general partner. Conflicts of interest may arise between our general partner and its affiliates, including Axel Johnson, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts, our general partner may favor its own interests and the interests of its affiliates, including Axel Johnson, over the interests of our common unitholders. These conflicts include, among others, the following situations:

Our general partner is allowed to take into account the interests of parties other than us, such as its affiliates, including Axel Johnson, in resolving conflicts of interest, which has the effect of limiting its duty to our unitholders.

Affiliates of our general partner, including Axel Johnson and Sprague Holdings, may engage in competition with us.

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Neither our partnership agreement nor any other agreement requires Axel Johnson or Sprague Holdings to pursue a business strategy that favors us, and Axel Johnson s directors and officers have a fiduciary duty to make decisions in the best interests of the stockholders of Axel Johnson.

Some officers of our general partner who provide services to us devote time to affiliates of our general partner.

Our partnership agreement limits the liability of and reduces the duties owed by our general partner to us and our common unitholders, and also restricts the remedies available to our unitholders for actions that, without the limitations, might constitute breaches of fiduciary duty.

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

Our general partner determines the amount and timing of asset purchases and sales, borrowings, issuances of additional partnership securities and the creation, reductions or increases of cash reserves, each of which can affect the amount of cash that is available for distribution to our unitholders, including distributions on our subordinated units, and to the holders of the incentive distribution rights, as well as the ability of the subordinated units to convert to common units.

Our general partner determines the amount and timing of any capital expenditures and whether a capital expenditure is classified as a maintenance capital expenditure, which reduces distributable cash flow. Such determination can affect the amount of distributable cash flow, including distributions on our subordinated units, and to the holders of the incentive distribution rights, as well as the ability of the subordinated units to convert to common units. Our partnership agreement does not limit the amount of maintenance capital expenditures that our general partner can cause us to make.

Our partnership agreement and the services agreement allow our general partner to determine, in good faith, the expenses that are allocable to us. Our partnership agreement and the services agreement do not limit the amount of expenses for which our general partner and its affiliates may be reimbursed. These expenses include salary, bonus, incentive compensation and other amounts paid to persons, including affiliates of our general partner, who perform services for us or on our behalf.

Our general partner may cause us to borrow funds in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make a distribution on the subordinated units, to make incentive distributions or to accelerate the expiration of the subordination period.

Our partnership agreement permits us to distribute up to $25.0 million as distributable cash flow, even if it is generated from sources that would otherwise constitute capital surplus, and this cash may be used to fund distributions on our subordinated units or the incentive distribution rights.

Our partnership agreement does not restrict our general partner from entering into additional contractual arrangements with any of its affiliates on our behalf.

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

Our general partner may exercise its right to call and purchase all of the common units not owned by it and its affiliates if it and its affiliates own more than 80% of all outstanding common units.

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

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

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

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Under the terms of our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, does not apply to our general partner or any of its affiliates, including their executive officers, directors and owners. Other than as provided in our omnibus agreement, any such person or entity that becomes aware of a potential transaction, agreement, arrangement or other matter that may be an opportunity for us will not have any duty to communicate or offer such opportunity to us. Any such person or entity will not be liable to us or to any limited partner for breach of any fiduciary duty or other duty by reason of the fact that such person or entity pursues or acquires such opportunity for itself, directs such opportunity to another person or entity or does not communicate such opportunity or information to us. This may create actual and potential conflicts of interest between us and affiliates of our general partner and result in less than favorable treatment of us and our unitholders.

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

Other than under our credit agreement, our general partner intends to limit 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 duty to act in good faith, 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 distributable cash flow otherwise available for distribution to our unitholders.

Our partnership agreement limits our general partner s duties to our unitholders.

Our partnership agreement contains provisions that modify and reduce the standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner, or otherwise free of fiduciary duties to us and our unitholders. This entitles our general partner to consider only the interests and factors that it desires and relieves it of any duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or our limited partners. Examples of decisions that our general partner may make in its individual capacity include:

- How to allocate business opportunities among us and its other affiliates;
- Whether to exercise its limited call right;
- How to exercise its voting rights with respect to any units it owns;
- Whether to exercise its registration rights with respect to any units it owns; and
- Whether to consent to any merger or consolidation of the partnership or amendment to the partnership agreement.

By purchasing a common unit, a unitholder is treated as having consented to the provisions in the partnership agreement, including the provisions discussed above.

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

Provides that whenever our general partner makes a determination or takes, or declines to take, any other action in its capacity as our general partner, our general partner is required to make such determination, or take or decline to take such other action, in good faith and will not be subject to any other or different standard imposed by our partnership agreement, Delaware law or any other law, rule or regulation, or at equity;

Provides that a determination, other action or failure to act by our general partner, the board of directors of our general partner or any committee thereof (including the conflicts committee) will be deemed to be in good faith unless our general partner, the board of directors of our general partner or any committee thereof believed such determination, other action or failure to act was adverse to the interests of the partnership;

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

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

Provides that our general partner will not be in breach of its obligations under the partnership agreement or its duties to us or our limited partners if a transaction with an affiliate or the resolution of a conflict of interest is:

(1) 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; or

(2) Approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner and its affiliates.

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 then it will be presumed that, in making its decision, taking any action or failing to act, 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.

Cost reimbursements and fees due to our general partner and its affiliates for services provided to us or on our behalf, which may be determined in our general partner s sole discretion, may be substantial and will reduce our distributable cash flow.

Under our partnership agreement, prior to making any distribution on the common units, our general partner and its affiliates shall be reimbursed for all costs and expenses that they incur on our behalf for managing and controlling our business and operations. Pursuant to the terms of the services agreement, our general partner will agree to provide certain general and administrative services and operational services to us, and we will agree to reimburse our general partner and its affiliates for all costs and expenses incurred in connection with providing such services to us, including salary, bonus, incentive compensation, insurance premiums and other amounts allocable to the employees and directors of our general partner or its affiliates that perform services on our behalf. Our general partner and its affiliates also may provide us other services for which we may be charged fees as determined by our general partner. Our partnership agreement and the services agreement do not limit the amount of expenses for which our general partner and its affiliates may be reimbursed. Payments to our general partner and its affiliates may be substantial and will reduce the amount of distributable cash flow.

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

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business and, therefore, limited ability to influence management s decisions regarding our business.

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Unitholders did not elect our general partner or the board of directors of our general partner and will have no right to elect our general partner or the board of directors of our general partner on an annual or other continuing basis. The board of directors of our general partner is chosen by Sprague Holdings, a wholly-owned subsidiary of Axel Johnson and the sole member of our general partner. Furthermore, if the unitholders are dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. As a result of these limitations, the price at which our common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price.

The unitholders will be unable to remove our general partner without its consent because our general partner and its affiliates own sufficient units to be able to prevent its removal. The vote of the holders of at least 66 $^2/_3$% of all outstanding common units and subordinated units voting together as a single class is required to remove our general partner. Sprague Holdings owns 57.8% of the common units and subordinated units. If our general partner is removed without cause during the subordination period and no units held by the holders of our subordinated units or their affiliates are voted in favor of that removal, all remaining subordinated units will automatically convert into common units and any existing arrearages on the common units will be extinguished. A removal of our general partner under these circumstances would adversely affect the common units by prematurely eliminating their distribution and liquidation preference over the subordinated units, which would otherwise have continued until we had met certain distribution and performance tests, and by eliminating existing arrangements, if any.

Cause is narrowly defined to mean that a court of competent jurisdiction has entered a final, non-appealable judgment finding the general partner liable for actual fraud or willful misconduct in its capacity as our general partner. Cause does not include most cases of charges of poor management of our business.

Furthermore, unitholders voting rights are further restricted by the partnership agreement provision 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 transferees and persons who acquired such units resulting in ownership of at or in excess of such levels with the prior approval of the board of directors of our general partner, cannot vote on any matter.

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

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

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

The incentive distribution rights held by Sprague Holdings may be transferred to a third party without unitholder consent.

Sprague Holdings may transfer the incentive distribution rights to a third party at any time without the consent of our unitholders. If Sprague Holdings transfers the incentive distribution rights to a third party but retains its ownership interest in our general partner, our general partner may not have the same incentive to grow our partnership and increase quarterly distributions to unitholders over time as it would if Sprague Holdings had retained ownership of the incentive distribution rights. For example, a transfer of incentive distribution rights by

Sprague Holdings could reduce the likelihood of Axel Johnson accepting offers made by us relating to assets owned by it, as Axel Johnson would have less of an economic incentive to grow our business, which in turn may impact our ability to grow our asset base.

We may issue additional units without unitholder approval, which would dilute unitholder interests.

At any time, we may issue an unlimited number of limited partner interests of any type without the approval of our unitholders. Further, neither our partnership agreement nor our credit agreement prohibits the issuance of equity securities that may effectively rank senior to our common units. The issuance by us of additional common units or other equity interests of equal or senior rank will have the following effects:

- Our unitholders proportionate ownership interest in us will decrease;
- The amount of distributable cash flow on each unit may decrease;
- Because a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution borne by our common unitholders will increase;
- The ratio of taxable income to distributions may increase;
- The relative voting strength of each previously outstanding unit may be diminished; and
- The market price of our common units may decline.

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

As of March 20, 2014, Sprague Holdings holds 1,571,970 common units and 10,071,970 subordinated units. All of the subordinated units will convert into common units at the end of the subordination period (which could occur as early as December 31, 2016) and may convert earlier under certain circumstances. Additionally, we have agreed to provide Sprague Holdings with certain registration rights (which may facilitate the sale by Sprague Holdings of its common and subordinated units into the public markets). The sale of these units in the public or private markets, or the perception that such sales might occur, could have an adverse impact on the price of the common units or on any trading market that may develop.

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 limited 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.

Our general partner s discretion in establishing cash reserves may reduce the amount of distributable cash flow that we distribute.

The partnership agreement permits the general partner to reduce the amount of distributable cash flow distributed to our unitholders by establishing cash reserves for the proper conduct of our business, to comply with applicable law or agreements to which we are a party or to provide funds for future distributions to partners.

Our general partner may cause us to borrow funds in order to make cash distributions, even where the purpose or effect of the borrowing benefits the general partner or its affiliates.

In some instances, our general partner may cause us to borrow funds from its affiliates, including Axel Johnson, or from third parties in order to permit the payment of cash distributions. These borrowings are permitted even if the purpose and effect of the borrowing is to enable us to make a distribution on the subordinated units, to make incentive distributions or to hasten the expiration of the subordination period.

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

If at any time our general partner and its affiliates own more than 80% of our common units, our general partner will have the right, but not the obligation, which it may assign to any of its affiliates or to us, to acquire all, but not less than all, of the common units held by unaffiliated persons. As a result, you may be required to sell your common units at an undesirable time or price, including at a price below the then-current market price, and may not receive any return on your investment. You may also incur a tax liability upon a sale of your units. As of March 20, 2014, our general partner and its affiliates owned approximately 15.6% of our common units. At the end of the subordination period (which could occur as early as December 31, 2016), assuming no additional issuances of common units (other than upon the conversion of the subordinated units), our general partner and its affiliates will own approximately 57.8% of our common units.

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

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. 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 jurisdictions. You could be liable for 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 the general partner, to approve some amendments to our partnership agreement or to take other actions under our partnership agreement constitutes control of our business.

A restatement of net income or a reversal or change of estimates affecting net income made after the end of the subordination period but affecting net income during the subordination period will not retroactively affect the conversion of the subordinated units even if we would not have had sufficient distributable cash flow based on such restated or adjusted net income to permit conversion.

Our subordinated units will convert into common units upon the satisfaction of certain tests involving the calculation of distributable cash flow on a historical basis. Distributable cash flow is calculated based on net income, which is a GAAP measure. If net income for a period during the subordination period is restated after the end of the subordination period or if estimates affecting net income made during the subordination period are reversed or changed after the end of the subordination period, it will not retroactively affect the conversion of subordinated units even if we would not have had sufficient distributable cash flow during the subordination period based on such restated or adjusted net income to permit conversion.

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, or the Delaware Act, we may not make a distribution to you if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of the impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Transferees of common units are liable for the obligations of the transferor to make contributions to the partnership that are known to the transferee at the time of the transfer and for unknown obligations if the liabilities could be determined from the partnership agreement. Liabilities to partners on account of their partnership interest and liabilities that are non-recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

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

The holder or holders of a majority of the incentive distribution rights (currently Sprague Holdings) have the right, in their discretion and without the approval of the conflicts committee of the board of directors of our general partner or the holders of our common units, at any time when there are no subordinated units outstanding and the holders received distributions on their incentive distribution rights at the highest level to which they are entitled (50.0%) for each of the prior four consecutive fiscal quarters, to reset the initial target distribution levels at higher levels based on our distributions at the time of the exercise of the reset election. Following a reset election, the minimum quarterly distribution will be adjusted to equal the reset minimum quarterly distribution, and the target distribution levels will be reset to correspondingly higher levels based on percentage increases above the reset minimum quarterly distribution. Sprague Holdings has the right to transfer the incentive distribution rights at any time, in whole or in part, and any transferee holding a majority of the incentive distribution rights shall have the same rights as Sprague Holdings relative to resetting target distributions.

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

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

As a limited partnership, we are not required 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, as is required for other NYSE-listed entities. Accordingly, unitholders do not have the same protections afforded to certain entities, including most corporations, that are subject to all of the NYSE corporate governance requirements.

Tax Risks to Common Unitholders

Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service (IRS) were to treat us as a corporation for federal income tax purposes or if we become subject to a material amount of entity-level taxation for state tax purposes, then our cash available for distribution would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for U.S. federal income tax purposes. A publicly traded partnership such as us may be treated as a corporation for federal income tax purposes unless it satisfies a qualifying income requirement. Based on our current operations we believe that we satisfy the qualifying income requirement and will be treated as a partnership. Failing to meet the qualifying income requirement 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. We have not requested, and do not plan to request, a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes.

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 additional state income tax at varying rates. Distributions to our unitholders would generally be taxed again as corporate dividends, and no income, gains, losses or deductions would flow through to the limited partners. Because a tax would be imposed upon us as a corporation, our cash available for distributions would be substantially reduced. Therefore, treatment of us as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units.

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

We are currently subject to entity level taxes and fees in a number of states, and such taxes and fees will reduce the distributable cash flow. Changes in current state laws 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 such additional taxes on us by other states in which we do business will further reduce the distributable cash flow available for distribution to unitholders.

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

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. For example, from time to time members of Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships. One such legislative proposal would eliminate the qualifying income exception to the treatment of all publicly traded partnerships as corporations upon which we rely for our treatment as a partnership for U.S. federal income tax purposes. Any modification to the U.S. federal income tax laws and interpretations thereof may be applied retroactively and could make it more difficult or impossible to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. We are unable to predict whether any of these changes, or other proposals, will be reintroduced or will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

Our unitholders will be required to pay taxes on their share of our income even if they do not receive any cash distributions from us.

Because our unitholders will be treated as partners to whom we will allocate taxable income that could be different in amount than the cash we distribute, our unitholders will be required to pay any federal income taxes and, in some cases, state and local income taxes on their share of our taxable income whether or not they receive 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.

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 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.

Sprague Holdings currently directly and indirectly owns more than 50% of the total interests in our capital and profits interests. Therefore, a transfer by Sprague Holdings of all or a portion of its interests in us, along with transfers by other unitholders, could result in a termination of our partnership for federal income tax purposes. Our termination would, among other things, result in the closing of our taxable year for all unitholders and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a calendar year, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership for federal income 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.

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

If our unitholders sell their common units, they will recognize a gain or loss equal to the difference between the amount realized and our unitholders tax basis in those common units. Because distributions in excess of their allocable share of our net taxable income decrease their tax basis in common units, the amount, if any, of such prior excess distributions with respect to the units our unitholders sell will, in effect, become taxable income to our unitholders if they sell such units at a price greater than their tax basis in those units, even if the price they receive is less than their original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder s share of our nonrecourse liabilities, if our unitholders sell their units, they may incur a tax liability in excess of the amount of cash they receive from the sale.

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

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

The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may materially and adversely affect the market for our common units and the price at which they trade. Our costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner because the costs will reduce our distributable cash flow.

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

Due to a number of factors including our inability to match transferors and transferees of common units, we will adopt depreciation and amortization positions that may not conform to all aspects of existing Treasury

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Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from the sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to our unitholders tax returns.

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

We generally prorate our items of income, gain, loss and deduction between transferors and transferees of our common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred. Nonetheless, we allocate certain deductions for depreciation of capital additions based upon the date the underlying property is placed in service. The use of this proration method may not be permitted under existing Treasury Regulations, and, although the U.S. Treasury Department issued proposed Treasury Regulations allowing a similar monthly simplifying convention, such regulations are not final and do not specifically authorize the use of the proration method we have adopted. If the IRS were to successfully challenge our proration method, we may be required to change the allocation of items of income, gain, loss, and deduction among our unitholders.

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

Because there are no specific rules governing the federal income tax consequences of loaning a partnership interest, a unitholder whose common units are the subject of a securities loan may be considered to have disposed of the loaned units. In that case, such unitholder may no longer be treated for tax purposes as a partner with respect to those common units during the period of the loan and the unitholder may be required to recognize gain or loss from such disposition. Moreover, during the period of the loan, any of our income, gain, loss or deduction with respect to those common units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those common units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a securities loan should modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.

Unitholders may be subject to state and local taxes and return filing requirements in jurisdictions where they do not live as a result of investing in our common units.

In addition to federal income taxes, unitholders will likely be subject to other taxes, including state and local and non-U.S. taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if they do not live in any of those jurisdictions. 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, unitholders may be subject to penalties for failure to comply with those requirements. We conduct business and own property in numerous states, most of which impose a personal income tax as well as an income tax on corporations and other entities. We may own property or conduct business in other states or non-U.S. countries in the future. In some jurisdictions, tax losses may not produce a tax benefit in the year incurred and may not be available to offset income in subsequent taxable years. It is the unitholder s responsibility to file all U.S. federal, state, local and non-U.S. tax returns.

Item 1B. Unresolved Staff Comments

None.

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Item 2. Properties

The following tables set forth information with respect to our 15 owned and/or operated terminals.

Liquids Storage Terminal	Number of Storage Tanks(1)	Storage Tank Capacity (Bbls)(1)	Principal Products
South Portland, ME	29	1,411,100	refined products; asphalt; clay slurry
Searsport, ME	18	1,254,400	refined products; caustic soda; asphalt
Newington, NH: River Road	29	1,157,200	refined products; tallow
Bridgeport, CT(2)	11	1,120,600	refined products
Albany, NY	11	1,104,500	refined products
Newington, NH: Avery Lane	11	679,000	refined products; asphalt
Quincy, MA	9	657,000	refined products
Providence, RI(3)	5	619,800	refined products; asphalt
Oswego, NY	4	339,200	refined products; asphalt
Everett, MA	4	317,600	asphalt
Quincy, MA: TRT(4)	4	304,200	refined products
New Bedford, MA(5)	2	85,900	refined products
Mount Vernon, NY	7	72,100	refined products
Stamford, CT	3	46,600	refined products
Total	**147**	**9,169,200**	

Dry Storage Terminal	Number of Storage Pads and Warehouses	Storage Capacity (Square Feet)	Principal Products and Materials
Newington, NH: River Road(6)	3 pads	431,000	salt; gypsum
Searsport, ME	3 warehouses;	101,000	break bulk; salt; petroleum coke;
	7 pads	310,000	heavy lift
Portland, ME(7)	7 warehouses;	215,000	break bulk; coal
	4 pads	180,000	
South Portland, ME	3 pads	230,000	salt; coal
Providence, RI	1 pad	75,000	salt
Total	**10 warehouses; 18 pads**	1,542,000	

(1) We also have an aggregate of approximately 1.4 million barrels of additional storage capacity attributable to 41 storage tanks not currently in service. These tanks are not necessary for the operation of our business at current

levels. In the event that such additional storage capacity were desired, additional time and capital would be required to bring any of such storage tanks back into service.

(2) We acquired the Bridgeport terminal on July 31, 2013.

(3) One tank with storage capacity of approximately 136,000 barrels is leased from a subsidiary of Dominion Resources, Inc., an unaffiliated third party.

(4) Operating assets and real estate are leased from Twin Rivers Technology L.P., an unaffiliated third party.

(5) Operating assets and real estate are leased from Sprague Massachusetts Properties LLC, a wholly-owned subsidiary of Sprague Holdings. The New Bedford terminal is subject to a purchase and sale agreement pursuant to which a third party has agreed to acquire the terminal from Sprague Massachusetts Properties LLC. The acquisition is subject to certain conditions that are beyond the control of Sprague Massachusetts Properties LLC. Subject to those conditions, the acquisition may be consummated on or before January 5, 2016. In the event that such sale is consummated, our terminal operating agreement with Sprague Holdings and Sprague Massachusetts Properties LLC will automatically terminate. We do not believe that the sale will be consummated prior to December 31, 2014.

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(6) The terminal also has two silos capable of storing a total of approximately 26,000 tons of cement.
(7) Real estate and two storage buildings are leased from Merrill Industries Inc., an unaffiliated third party, and the balance of the assets are owned by us.

Item 3. Legal Proceedings

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, we are not a party to any litigation or governmental or other proceeding that we believe will have a material adverse impact on our consolidated financial condition or results of operations.

Item 4. Mine Safety Disclosures

Not applicable.

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Part II

Item 5. Market for Our Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Our public common units began trading on the NYSE under the symbol SRLP on October 25, 2013. Prior to that time, there was no public market for our securities. As of March 20, 2014, Sprague Holdings owned 1,571,970 common units and 10,071,970 subordinated units, which together constitute a 57.8% ownership interest in us. We issued 8,500,000 common units to the public in connection with our IPO and 6,666 restricted units in accordance with the 2013 Long Term Incentive Plan for Director compensation. As of March 20, 2014, the closing market price for our common units was $18.42 per unit and there were approximately three unitholders of record of our common units. The actual number of unitholders is greater than the number of holders of record.

The following table sets forth the range of the high and low closing prices of our common units and cash distributions to common unitholders for the period from October 25, 2013, the date our shares began trading.

	Sales Price per Common Unit		Quarterly Cash Distribution per		
Quarter Ended	High	Low	Unit	Record Date	Distribution Date
December 31, 2013 (1)(2)	$ 18.24	$ 16.89	$ 0.2825	February 10, 2014	February 14, 2014

(1) Sales price per common unit from October 25, 2013, the commencement date of trading.
(2) Quarterly cash distribution per unit was prorated for the days from October 30, 2013, the closing date of the IPO, through December 31, 2013.

Certain Information from Our Partnership Agreement

Set forth below is a summary of certain provisions of our partnership agreement that relate to cash distributions and incentive distribution rights.

Our Cash Distribution Policy

It is our intent to distribute, within 45 days after the end of each fiscal quarter, the minimum quarterly distribution of $0.4125 per unit on all our units ($1.65 per unit on an annualized basis) to the extent we have sufficient cash from our operations after the establishment of cash reserves and payment of our expenses. The board of directors of our general partner will determine the amount of our quarterly distributions and may change our distribution policy at any time. The board of directors of our general partner may determine to reserve or reinvest excess cash in order to permit gradual or consistent increases in quarterly distributions and may borrow to fund distributions in quarters when we generate less distributable cash flow than necessary to sustain or grow our cash distributions per unit.

There is no guarantee that unitholders will receive quarterly cash distributions from us. We do not have a legal obligation to pay distributions at our minimum quarterly distribution rate or at any other rate. Uncertainties regarding future cash distributions to our unitholders include, among other things, the following factors:

Our cash distribution policy may be affected by restrictions on distributions under our credit agreement as well as by restrictions in future debt agreements that we enter into. Specifically, our credit agreement contains financial tests and covenants that we must satisfy. Should we be unable to satisfy these restrictions or if we are otherwise in default under our credit agreement, we may be prohibited from making cash distributions to you notwithstanding our stated cash distribution policy.

Our general partner will have the authority to establish cash reserves for the prudent conduct of our business and for future cash distributions to our unitholders, and the establishment of or increase in those reserves could result in a reduction in cash distributions from levels we currently anticipate pursuant to our stated cash distribution policy.

Under Section 17-607 of the Delaware Act we may not make a distribution if the distribution would cause our liabilities to exceed the fair value of our assets.

We may lack sufficient cash to make distributions to our unitholders due to a number of operational, commercial and other factors or increases in our operating costs, general and administrative expenses, principal and interest payments on our outstanding debt and working capital requirements.

If we make distributions out of capital surplus, as opposed to distributable cash flow, any such distributions would constitute a return of capital and would result in a reduction in the minimum quarterly distribution and the target distribution levels. We do not anticipate that we will make any distributions from capital surplus.

Our ability to make distributions to our unitholders depends on the performance of our subsidiaries and their ability to distribute cash to us. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, the provisions of future indebtedness, applicable state partnership, limited liability company and corporate laws and other laws and regulations.

See Item 1A. Risk Factors Risk Related to our Business.

General Partner Interest

Our general partner owns a non-economic general partner interest in us, which does not entitle it to receive cash distributions. However, our general partner may in the future own common units or other equity interests in us and will be entitled to receive distributions on any such interest.

Subordinated Units

Sprague Holdings owns, directly or indirectly, all of our subordinated units. The principal difference between our common units and subordinated units is that during the period referred to in our partnership agreement as the subordination period , the common units have the right to receive distributions of cash from distributable cash flow each quarter in an amount equal to $0.4125 per common unit, which is the amount defined in our partnership agreement as the minimum quarterly distribution, plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, before any distributions of cash from distributable cash flow may be made on the subordinated units. Furthermore, no arrearages will accrue or be paid on the subordinated units.

Upon expiration of the subordination period, any outstanding arrearages in payment of the minimum quarterly distribution on the common units will be extinguished (not paid), each outstanding subordinated unit will immediately convert into one common unit and will thereafter participate pro rata with the other common units in distributions.

Incentive Distribution Rights

Sprague Holdings currently holds incentive distribution rights that entitle it to receive increasing percentages, up to a maximum of 50.0%, of the cash we distribute from operating surplus (as defined below) in excess of $0.61875 per unit per quarter. The maximum distribution of 50.0% does not include any distributions that our sponsor may receive on any limited partner units that it owns.

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Item 6. Selected Financial Data

The following table presents selected historical consolidated financial and operating data of our predecessor, Sprague Operating Resources LLC, as of the dates and for the periods indicated. The selected historical consolidated financial data presented as of December 31, 2012, 2011, 2010 and 2009 and for the years ended December 31, 2012, 2011, 2010 and 2009 are derived from the audited historical consolidated financial statements of Sprague Operating Resources LLC. The selected historical financial data as of December 31, 2013 and for the year ended December 31, 2013 includes the combined results of the Predecessor through October 29, 2013 and the Partnership for the period from October 30, 2013 through December 31, 2013, all derived from the Partnership s 2013 audited consolidated financial statements.

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The following table presents the non-GAAP financial measure adjusted EBITDA, which we use in our business as an important supplemental measure of our performance. We define and explain this measure under Non-GAAP Financial Measures and reconcile it to net income, its most directly comparable financial measure calculated and presented in accordance with GAAP.

		Predecessor			
	Years Ended December 31,				
	2013	2012	2011	2010	2009
	(in thousands, except unit data and operating data)				
Statements of Operations Data:					
Net sales	$ 4,600,734	$ 4,043,907	$ 3,797,427	$ 2,817,191	$ 2,460,115
Cost of products sold	4,474,742	3,922,352	3,638,717	2,676,301	2,313,644
Gross margin	125,992	121,555	158,710	140,890	146,471
Operating costs and expenses					
Operating expenses	51,839	47,054	42,414	41,102	44,448
Selling, general and administrative	53,580	46,449	46,292	40,625	47,836
Write-off of deferred offering costs(1)		8,931			
Depreciation and amortization	15,452	11,665	10,140	10,531	10,615
Total operating costs and expenses	120,871	114,099	98,846	92,258	102,899
Operating income	5,121	7,456	59,864	48,632	43,572
Gain on acquisition of business		1,512	6,016		
Other income (expense)	568	(160)		894	
Interest income	603	534	755	503	383
Interest expense	(28,695)	(23,960)	(24,049)	(21,897)	(20,809)
(Loss) income before income taxes and equity in net (loss) income of foreign affiliate	(22,403)	(14,618)	42,586	28,132	23,146
Income tax (provision) benefit(2)	(5,097)	2,796	(16,636)	(10,288)	(11,843)
(Loss) income before equity in net income (loss) of foreign affiliate	(27,500)	(11,822)	25,950	17,844	11,303
Equity in net (loss) income of foreign affiliate		(1,009)	3,622	(2,123)	8,441
Net (loss)/income	$ (27,500)	$ (12,831)	$ 29,572	$ 15,721	$ 19,744
	$ 2,734				

Less Predecessor income through October 29, 2013										
Limited partners interest in net loss(3)	$	(30,234)								
Net loss per limited partner common unit-basic and diluted(3)	$	(1.50)								
Weighted average limited partner common units-basic and diluted(3)		10,071,970								
Adjusted EBITDA (unaudited)(4)	$	73,018	$	49,781	$	64,398	$	53,286	$	76,982
Cash Flow Data:										
Net cash (used in) provided by:										
Operating activities	$	(79,455)	$	163,129	$	(43,861)	$	24,997	$	159,074
Investing activities		(40,740)		(79,693)		(17,004)		(9,387)		(7,702)
Financing activities		117,634		(111,560)		88,882		(17,162)		(147,513)
Other Financial and Operating Data (unaudited):										
Capital expenditures(5)	$	22,079	$	7,293	$	7,255	$	9,587	$	7,237
Normal heating degree days(6)		6,752		6,787		6,752		6,752		6,752
Actual heating degree days(6)		6,624		5,803		6,284		6,117		6,912
Variance from normal heating degree days		(1.9)%		(14.5)%		(6.9)%		(9.4)%		2.4%
Variance from prior period actual heating degree days		14.1%		(7.7)%		2.7%		(11.5)%		4.4%
Total refined products volumes sold (barrels)		34,261		29,806		29,684		29,797		29,298
Variance from refined products volume from prior period		14.9%		0.4%		(0.4)%		1.7%		(19.1)%
Total natural gas volumes sold (MMBtus)		51,979		49,417		50,741		52,012		50,887
Variance from natural gas volume from prior period		5.2%		(2.6)%		(2.4)%		2.2%		(5.7)%

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	2013	2012	2011	2010	2009
		Predecessor Years Ended December 31,			
	(in thousands, except unit data and operating data)				
Balance Sheet Data (at period end):					
Cash and cash equivalents	$ 998	$ 3,691	$ 31,829	$ 3,854	$ 5,325
Property, plant and equipment, net	116,807	177,080	110,743	103,461	102,949
Total assets	853,590	1,054,247	970,050	867,995	843,517
Total debt (including capital lease obligations)	462,760	555,619	524,377	408,304	373,215
Total liabilities	823,631	913,041	791,649	697,811	657,104
Total unitholders /member s/stockholder s equity	29,959	141,206	178,401	170,184	186,413

(1) During the year ended December 31, 2012, we delayed the timing of this public offering and, as a result, deferred offering costs of $8.9 million were charged against earnings.

(2) Prior to the completion of the IPO, Sprague Energy Corp., which was converted into a limited liability company and renamed Sprague Operating Resource LLC on November 7, 2011, prepared its income tax provision as if it had filed a consolidated federal income tax return and state tax returns as required. Commencing with the closing of the IPO, the Partnership will be treated as pass through entity for federal income tax purposes. For pass through entities, all income, expenses, gains, losses and tax credits generated flow through to their owners and, accordingly, do not result in a provision for income taxes in our financial statements.

(3) Calculated based on operations since October 30, 2013, the date of the closing of the IPO. See Note 21 to the Consolidated Financial Statements included elsewhere in this report for the net income per limited partner unit calculation.

(4) For a discussion of the non-GAAP financial measure adjusted EBITDA, please read Non-GAAP Financial Measures below.

(5) Includes approximately $7.4 million, $6.0 million, $5.7 million, $8.1 million and $6.5 million of maintenance capital expenditures for the years ended December 31, 2013, 2012, 2011, 2010 and 2009. Maintenance capital expenditures are capital expenditures made to replace assets or to maintain the long-term operating capacity of our assets or operating income.

(6) As reported by the NOAA/National Weather Service for the New England oil home heating region over the period 1981-2011.

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Non-GAAP Financial Measures

We present the non-GAAP financial measures EBITDA and adjusted EBITDA in this Annual Report. We define EBITDA as net income before interest, income taxes, depreciation and amortization. We define adjusted EBITDA as EBITDA decreased by total commodity derivative gains and losses included in net income (loss) and increased by realized commodity derivative gains and losses included in net income (loss), in each case with respect to refined products and natural gas inventory and natural gas transportation contracts, decreased by gains on acquisition of business, increased by the write-off of deferred offering costs and adjusted for the net impact of bio-fuel excise tax credits in 2013/2012. Adjusted EBITDA is used as a supplemental financial measure by our management, and EBITDA and adjusted EBITDA are used as supplemental financial measures by external users of our financial statements, such as commercial banks and ratings agencies, to assess:

- The financial performance of our assets, operations and return on capital without regard to financing methods, capital structure or historical cost basis;
- The ability of our assets to generate cash sufficient to pay interest on our indebtedness and make distributions to our equity holders;
- Repeatable operating performance that is not distorted by non-recurring items or market volatility; and
- The viability of acquisitions and capital expenditure projects.

For a discussion of how our management uses adjusted EBITDA, please read Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations How Management Evaluates Our results of Operations Adjusted Gross Margin and Adjusted EBITDA.

The GAAP measure most directly comparable to EBITDA and adjusted EBITDA is net income. The non-GAAP financial measures of EBITDA and adjusted EBITDA should not be considered as an alternative to net income or any other measure of financial performance or liquidity presented in accordance with GAAP. EBITDA and adjusted EBITDA are not presentations made in accordance with GAAP and have important limitations as analytical tools. You should not consider EBITDA or adjusted EBITDA in isolation or as substitutes for analysis of our results as reported under GAAP. Because EBITDA and adjusted EBITDA exclude some, but not all, items that affect net income and is defined differently by different companies, our definitions of EBITDA and adjusted EBITDA may not be comparable to similarly titled measures of other companies.

We recognize that the usefulness of EBITDA and adjusted EBITDA as an evaluative tool may have certain limitations, including:

- EBITDA and adjusted EBITDA do not include interest expense. Because we have borrowed money in order to finance our operations, interest expense is a necessary element of our costs and impacts our ability to generate profits and cash flows. Therefore, any measure that excludes interest expense may have material limitations;

EBITDA and adjusted EBITDA do not include depreciation and amortization expense. Because we use capital assets, depreciation and amortization expense is a necessary element of our costs and ability to generate profits. Therefore, any measure that excludes depreciation and amortization expense may have material limitations;

EBITDA and adjusted EBITDA do not include provision for income taxes. Because the payment of income taxes is a necessary element of our costs, any measure that excludes income tax expense may have material limitations;

EBITDA and adjusted EBITDA do not reflect capital expenditures or future requirements for capital expenditures or contractual commitments;

EBITDA and adjusted EBITDA do not reflect changes in, or cash requirements for, working capital needs; and

EBITDA and adjusted EBITDA do not allow us to analyze the effect of certain recurring and non-recurring items that materially affect our net income or loss.

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The following table presents a reconciliation of EBITDA and adjusted EBITDA to net income, the most directly comparable GAAP financial measure, on a historical basis, as applicable, for each of the years indicated:

		Predecessor Years Ended December 31, (in thousands)			
	2013	**2012**	**2011**	**2010**	**2009**
Reconciliation of EBITDA to net income:					
Net (loss) income	$ (27,500)	$ (12,831)	$ 29,572	$ 15,721	$ 19,744
Add/(deduct):					
Interest expense, net	28,092	23,426	23,294	21,394	20,426
Tax expense (benefit)	5,097	(2,796)	16,636	10,288	11,843
Depreciation and amortization	15,452	11,665	10,140	10,531	10,615
EBITDA	$ 21,141	$ 19,464	$ 79,642	$ 57,934	$ 62,628
Deduct: total commodity derivative (gains) losses included in net income (loss)(1)	76,203	26,818	34,848	38,975	24,545
Add: realized commodity derivative gains (losses) included in net income (loss)(1)	(19,305)	(8,941)	(44,076)	(43,623)	(10,191)
Add/(deduct):					
Gain on acquisition of business(2)		(1,512)	(6,016)		
Write-off of deferred offering costs(3)		8,931			
Bio-fuel excise tax credits(4)	(5,021)	5,021			
Adjusted EBITDA	$ 73,018	$ 49,781	$ 64,398	$ 53,286	$ 76,982

(1) Both total commodity derivative gains and losses and realized commodity derivative gains and losses include amounts paid to enter into the derivative contracts.

(2) Represents non-cash gains associated with (i) the re-measurement to fair value of our predecessor s 50% interest in Kildair in connection with its acquisition of the remaining 50% interest therein in 2012 and, (ii) the acquisition of an oil terminal at below fair value in 2011.

(3) During the year ended December 31, 2012, we delayed the filing of the IPO and, as a result, deferred offering costs of $8.9 million were charged against earnings. Please see Note 19 to our consolidated financial statements.

(4) On January 2, 2013, the federal government enacted legislation that reinstated an excise tax credit program available for certain of our bio-fuel blending activities. This program had previously expired on December 31, 2011 and was reinstated retroactively to January 1, 2012. During the year ended December 31, 2013, we recorded federal excise tax credits of $5.0 million related to our bio-fuel blending activities that had occurred during the year ended December 31, 2012. These credits have been recorded as a reduction of cost of products sold and, therefore, resulted in an increase in adjusted gross margin for the year ended December 31, 2013. This adjustment reflects the effect on our adjusted EBITDA had these credits been recorded in the period in which the blending activity took place.

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

On October 30, 2013, we completed an initial public offering of 8,500,000 common units, representing a 42.2% limited partnership interest in us, at an initial public offering price of $18.00 per unit. Total proceeds of the sale of the common units were $140.3 million after deducting underwriting discounts and commissions, the structuring fee and offering expenses.

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and notes to consolidated financial statements included elsewhere in this report, as well as the other financial information appearing elsewhere in this Annual Report.

EBITDA and Adjusted EBITDA are non-GAAP financial measures of performance that have limitations and should not be considered as a substitute for net income or cash provided by (used in) operating activities. Please see below for a discussion of our use of EBITDA and Adjusted EBITDA and a reconciliation to net income for the periods presented.

Cautionary Statements Concerning Forward-Looking Statements

This Annual Report, including without limitation, our discussion and analysis of our financial condition and results of operations, and any information incorporated by reference, contains statements that we believe are forward-looking statements . Forward-looking statements give our current expectations and contain projections of results of operations or of financial condition, or forecasts of future events. Words such as may , assume , forecast , position , predict , strategy , expect , intend , plan , estimate , anticipate , believe , project , budget , potential , or continu expressions are used to identify forward-looking statements. They can be affected by assumptions used or by known or unknown risks or uncertainties. Consequently, no forward-looking statements can be guaranteed. When considering these forward-looking statements, you should keep in mind the risk factors included in Part I, Item 1A Risk Factors of this Annual Report as well as the following risks and uncertainties:

We may not have sufficient distributable cash flow following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements to our general partner and its affiliates, to enable us to pay the minimum quarterly distribution to our unitholders.

Our business could be affected by a range of issues, such as dramatic changes in commodity prices, energy conservation, competition, the global economic climate, movement of products between foreign locales and the United States, changes in local, domestic and worldwide inventory levels, seasonality and supply, weather and logistics disruptions.

A significant decrease in demand for the products and services we sell could reduce our ability to make distributions to our unitholders.

Increases and/or decreases in the prices of the products we sell could adversely impact the amount of borrowing available for working capital under our credit agreement.

Our results of operations are affected by the overall forward market for the products we sell.

Our business is seasonal and generally our financial results are lower in the second and third quarters of the calendar year, which may result in our need to borrow money in order to make quarterly distributions to our unitholders during these quarters. Warmer weather conditions could adversely affect our home heating oil and residual oil sales.

Our risk management policies cannot eliminate all commodity risk. In addition, noncompliance with our risk management policies could result in significant financial losses.

Nonperformance by our customers, suppliers and counterparties could result in losses to us.

We are exposed to trade credit risk in the ordinary course of our business as well as risks associated with our trade credit support in the ordinary course of business.

Competition from alternative energy sources, energy efficiency and new technologies could result in loss of some of our customers or reduction in demand for our products and services.

Certain of our contracts must be renegotiated or replaced periodically and our results of operations may be affected if we are unable to renegotiate or replace such contracts.

Adverse developments in the geographic areas in which we operate could affect our results of operations.

Compliance with changes to both federal and state environmental and non-environmental regulations could have a material adverse effect on our businesses.

Any disruptions in our labor force could affect our business.

A serious disruption to our information technology systems could significantly limit our ability to manage and operate our business efficiently.

Any failure to develop or maintain adequate internal controls over financial reporting may affect our results of operation.

Our general partner and its affiliates have conflicts of interest and limited fiduciary duties, which may permit them to favor their own interests to the detriment of unitholders.

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

A significant increase in interest rates could adversely affect our ability to service our indebtedness.

The condition of credit markets may adversely affect us.

Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes. If the IRS were to treat us as a corporation for federal income tax purposes, our distributable cash flow would be substantially reduced.

Our unitholders will be required to pay taxes on their share of our income even if they do not receive any cash distributions from us.

The risk factors and other factors noted throughout this Annual Report could cause our actual results to differ materially from those contained in any forward-looking statement, and you are cautioned not to place undue reliance on any forward-looking statements.

Forward-looking statements speak only as of the date of this Annual Report (or other date as specified in this Annual Report) or as of the date given if provided in another filing with the SEC. We undertake no obligation, and disclaim any obligation, to publicly update or review any forward-looking statements to reflect events or circumstances after the date of such statements.

A reference to a Note herein refers to the accompanying Notes to Consolidated Financial Statements contained in Part IV, Item 15. Exhibits and Financial Statement Schedules of this Annual Report.

Overview

We are a Delaware limited partnership formed by Sprague Holdings and our general partner to engage in the purchase, storage, distribution and sale of refined products and natural gas, and to provide storage and handling services for a broad range of materials.

We are one of the largest independent wholesale distributors of refined products in the Northeast United States based on aggregate terminal capacity. We own and/or operate a network of 15 refined products and materials handling terminals strategically located throughout the Northeast that have a combined storage capacity of approximately 9.2 million barrels for refined products and other liquid materials, as well as approximately

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1.5 million square feet of materials handling capacity. We also have an aggregate of approximately 1.4 million barrels of additional storage capacity attributable to 41 storage tanks not currently in service. These tanks are not necessary for the operation of our business at current levels. In the event that such additional capacity were desired, additional time and capital would be required to bring any of such storage tanks into service. Furthermore, we have access to more than 60 third-party terminals in the Northeast through which we sell or distribute refined products pursuant to rack, exchange and throughput agreements.

We operate under four business segments: refined products, natural gas, materials handling and other operations. We evaluate the performance of our segments using adjusted gross margin, which is a non-GAAP financial measure used by management and external users of our consolidated financial statements to assess the economic results of operations. For a description of how we define adjusted gross margin, see Part II, Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations Adjusted Gross Margin and Adjusted EBITDA. For a reconciliation of adjusted gross margin to the GAAP measure most directly comparable thereto, see Part II, Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations.

On October 1, 2012, our Predecessor acquired control of Kildair, a Canadian distributor of residual fuel oil and asphalt and a commercial trucking business, by purchasing the remaining 50% equity interest. Prior to October 1, 2012, the results of operations of Kildair were recorded as equity in earnings of foreign affiliate. From October 1, 2012 and through the date of our IPO on October 30, 2013, the assets, liabilities and results of operations of Kildair have been consolidated into our financial statements, including our adjusted gross margin. We record Kildair s residual fuel oil and asphalt business in our refined products segment and their commercial trucking business in our other operations segment. Kildair is not part of our net assets following the completion of the IPO.

Our refined products segment purchases a variety of refined products, such as heating oil, diesel fuel, residual fuel oil, kerosene, jet fuel and gasoline (primarily from refining companies, trading organizations and producers), and sells them to our customers. We have wholesale customers who resell the refined products we sell to them and commercial customers who consume the refined products we sell to them. Our wholesale customers consist of more than 1,000 home heating oil retailers and diesel fuel and gasoline resellers. Our commercial customers include federal and state agencies, municipalities, regional transit authorities, large industrial companies, hospitals and educational institutions. For the years ended December 31, 2013 and 2012, we sold approximately 1.4 billion and 1.3 billion gallons of refined products, respectively. For the years ended December 31, 2013 and 2012, our refined products segment accounted for 60% and 56% of our adjusted gross margin, respectively.

We also purchase, sell and distribute natural gas to more than 5,000 commercial and industrial customer locations across 10 states in the Northeast and Mid-Atlantic. We purchase the natural gas we sell from natural gas producers and trading companies. For the years ended December 31, 2013 and 2012, we sold 52.0 Bcf and 49.4 Bcf of natural gas, respectively. For the years ended December 31, 2013 and 2012, our natural gas segment accounted for 22% and 19% of our adjusted gross margin, respectively.

Our materials handling business is a fee-based business and is generally conducted under multi-year agreements. We offload, store and/or prepare for delivery a variety of customer-owned products, including asphalt, clay slurry, salt, gypsum, coal, petroleum coke, caustic soda, tallow, pulp and heavy equipment. For the year ended December 31, 2013, we offloaded, stored and/or prepared for delivery 2.1 million short tons of products and 246.7 million gallons of liquid materials. For the year ended December 31, 2012, we offloaded, stored and/or prepared for delivery 2.6 million short tons of products and 248.5 million gallons of liquid materials. For the years ended December 31, 2013 and 2012, our materials handling segment accounted for 16% and 23% of our adjusted gross margin, respectively.

Our other operations segment includes the marketing and distribution of coal conducted in our South Portland and Portland, Maine terminals. For the years ended December 31, 2013 and 2012, our other operations segment accounted for approximately 2% of our adjusted gross margin.

We take title to the products we sell in our refined products, natural gas and other operations segments. We do not take title to any of the products in our materials handling segment. In order to manage our exposure to commodity price fluctuations, we use derivatives and forward contracts to maintain a position that is substantially balanced between product purchases and product sales.

Non-GAAP Financial Measures

We present the non-GAAP financial measures EBITDA, adjusted EBITDA and adjusted gross margin in this Annual Report. For a description of how we define EBITDA, adjusted EBITDA and adjusted gross margin, see below and Part I, Item 6 Selected Financial Data . A reconciliation of EBITDA, adjusted EBITDA and adjusted gross margin to the GAAP measures most directly comparable thereto, is presented below and in Part I, Item 6 Selected Financial Data .

How Management Evaluates Our Results of Operations

Our management uses a variety of financial and operational measurements to analyze our performance. These measurements include: (1) gross margin, (2) operating expenses, (3) selling, general and administrative (or SG&A) expenses, (4) heating degree days and (5) adjusted gross margin and adjusted EBITDA.

Gross Margin

We view gross margin as an important performance measure of the core profitability of our operations. We review gross margin data monthly for consistency and trend analysis. We define gross margin as net sales minus costs of products sold. Net sales include sales of refined products and natural gas and the fees associated with the provision of materials handling services. Product costs include the cost of acquiring the refined products and natural gas that we sell and all associated costs to transport such products to the point of sale, as well as costs that we incur in providing materials handling services to our customers.

Operating Expenses

Operating expenses are costs associated with the operation of the terminals and truck fleet used in our business. Employee wages, pension and 401(k) plan expenses, boiler fuel, repairs and maintenance, utilities, insurance, property taxes, services and lease payments comprise the most significant portions of our operating expenses. Commencing on October 30, 2013, employee wages and related employee expenses included in our operating expenses are incurred on our behalf by our General Partner and reimbursed by us. These expenses remain relatively stable independent of the volumes through our system but can fluctuate depending on the activities performed during a specific period.

Selling, General and Administrative Expenses

Our SG&A expenses include employee salaries and benefits, pension and 401(k) plan expenses, discretionary bonus, marketing costs, corporate overhead, professional fees, information technology and office space expenses. Commencing on October 30, 2013, employee wages, related employee expenses and certain rental costs included in our selling, general and administrative expenses are incurred on our behalf by our General Partner and reimbursed by us. We believe that our SG&A expenses will increase as a result of our becoming a publicly traded partnership.

Heating Degree Days

A degree day is an industry measurement of temperature designed to evaluate energy demand and consumption. Degree days are based on how much the average temperature departs from a human comfort level of 65°F. Each degree of temperature above 65°F is counted as one cooling degree day, and each degree of temperature below 65°F is counted as one heating degree day. Degree days are accumulated each day over the course of a year and can be compared to a monthly or a long-term average, or normal, to see if a month or a year was warmer or cooler than usual. Degree days are officially observed by the National Weather Service and officially archived by the National Climatic Data Center. For purposes of evaluating our results of operations, we use the normal heating degree day amount as reported by the NOAA/National Weather Service for the New England oil home heating region over the period of 1981-2011.

EBITDA

We define EBITDA as net income before interest, income taxes, depreciation and amortization. EBITDA is used as a supplemental financial measure by external users of our financial statements, such as investors, commercial banks, trade suppliers and research analysts, to assess:

- The financial performance of our assets, operations and return on capital without regard to financing methods, capital structure or historical cost basis;
- The ability of our assets to generate cash sufficient to pay interest on our indebtedness and make distributions to our equity holders; and
- The viability of acquisitions and capital expenditure projects.

EBITDA is not prepared in accordance with GAAP. EBITDA should not be considered an alternative to net income, operating income, cash flow from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. EBITDA excludes some, but not all, items that affect net income and operating income.

Adjusted Gross Margin and Adjusted EBITDA

Management utilizes adjusted gross margin and adjusted EBITDA to assist it in reviewing our financial results and managing our business segments. We define adjusted gross margin as gross margin decreased by total commodity derivative gains and losses included in net income (loss) and increased by realized commodity derivative gains and losses included in net income (loss), in each case with respect to refined products and natural gas inventory and natural gas transportation contracts. We define adjusted EBITDA as EBITDA decreased by total commodity derivative gains and losses included in net income (loss) and increased by realized commodity derivative gains and losses included in net income (loss), in each case with respect to refined products and natural gas inventory and natural gas transportation contracts, decreased by gains on acquisition of business, increased by the write-off of deferred offering costs and adjusted for the net impact of bio-fuel excise tax credits. Management believes that adjusted gross margin and adjusted EBITDA provide information that reflects our market or economic performance. We trade, purchase and sell energy commodities with market values that are constantly changing, which makes it important for management to evaluate our performance, as well as our physical and derivative positions, on a daily basis. Management reviews the daily operational performance of our supply activities, as well as our monthly financial results, on an adjusted gross margin and adjusted EBITDA basis. Adjusted gross margin and adjusted EBITDA have no impact on reported volumes or net sales.

Adjusted gross margin and adjusted EBITDA are used as supplemental financial measures by management to describe our operations and economic performance to commercial banks, trade suppliers and other credit suppliers, to assess:

- The economic results of our operations;

The market value of our inventory and natural gas transportation contracts for financial reporting to our lenders, as well as for borrowing base purposes; and

Repeatable operating performance that is not distorted by non-recurring items or market volatility.

Adjusted gross margin and adjusted EBITDA are not prepared in accordance with GAAP. Adjusted gross margin and adjusted EBITDA should not be considered as alternatives to net income, income from operations, cash flows from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP.

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Hedging Activities

We economically hedge our inventory within the guidelines set in our risk management policy. In a rising commodity price environment, the market value of our inventory will generally be higher than the cost of our inventory. For GAAP purposes, we are required to value our inventory at the lower of cost or market, or LCM. The hedges on this inventory will lose value as the value of the underlying commodity rises, creating hedging losses. Because we do not utilize hedge accounting, GAAP requires us to record those hedging losses in our statement of operations. In contrast, in a declining commodity price market we generally incur hedging gains. GAAP requires us to record those hedging gains in our statement of operations. The refined products inventory market valuation is calculated daily using independent bulk market price assessments from major pricing services (either Platts or Argus). These third-party price assessments are primarily based in New York Harbor, or NYH, with our inventory values determined after adjusting the NYH prices to the various inventory locations by adding expected cost differentials (primarily freight) compared to a NYH supply source. Our natural gas inventory is limited, with the valuation updated monthly based on the volume and prices at the corresponding inventory locations. The prices are based on the most applicable monthly Inside FERC, or IFERC, assessments published by Platts near the beginning of the following month.

Similarly, we can economically hedge our natural gas transportation assets (i.e., pipeline capacity) within the guidelines set in our risk management policy. Although we do not own any natural gas pipelines, we secure the use of pipeline capacity to support our natural gas requirements by either leasing capacity over a pipeline for a defined time period or by being assigned capacity from a local distribution company for supplying our customers. As the spread between the price of gas between the origin and delivery point widens (assuming the value exceeds the fixed charge of the transportation), the market value of the natural gas transportation contracts assets will increase. If the market value of the transportation asset exceeds costs, we can hedge or lock in the value of the transportation asset for future periods using available financial instruments. For GAAP purposes, the increase in value of the natural gas transportation assets is not recorded as income in the statement of operations until the transportation is utilized in the future (i.e., when natural gas is delivered to our customer). As the value of the natural gas transportation assets increase, the hedges on the natural gas transportation assets lose value, creating hedging losses in our statement of operations. The natural gas transportation assets market value is calculated daily based on the volume and prices at the corresponding pipeline locations. The daily prices are based on trader assessed quotes which represent observable transactions in the market place, with the end-month valuations primarily based on Platts prices where available or adding a location differential to the price assessment of a more liquid location.

As described above, pursuant to GAAP, we value our commodity derivative hedges at the end of each reporting period based on current commodity prices and record hedging gains or losses, as appropriate. Also as described above, and pursuant to GAAP, our refined products and natural gas inventory and natural gas transportation contract rights, to which the commodity derivative hedges relate, are not marked to market for the purpose of recording gains or losses. In measuring our operating performance, we rely on our GAAP financial results, but we also find it useful to adjust those numbers to show only the impact of hedging gains and losses actually realized in the period being reviewed. By making such adjustments, as reflected in adjusted gross margin and adjusted EBITDA, we believe that we are able to align more closely hedging gains and losses to the period in which the revenue from the sale of inventory and income from transportation contracts relating to those hedges is realized.

Recent Trends and Outlook

This section identifies certain trends and outlook that may affect our financial performance and results of operations in the future. Our economic and industry-wide trends and outlook include the following:

New, stricter environmental laws and regulations are increasing the compliance cost of terminal operations, which could adversely affect our results of operations and financial condition. Our operations are subject to federal, state and local laws and regulations regulating product quality specifications and other environmental matters. The trend in environmental regulation is towards more restrictions and limitations on activities that may affect the environment. We try to anticipate future regulatory requirements that might be imposed and to plan accordingly to remain in compliance with changing environmental laws and regulations and to minimize the costs of such compliance. However, there can be no assurances as to the timing and type of such changes in existing laws or the promulgation of new laws or the amount of any required expenditures associated therewith.

Dodd-Frank regulations could increase costs associated with hedging our commodity exposure. We employ derivatives of the types subject to regulation as part of the Dodd Frank Act. We, along with all participants in commodity markets, may face increased margin requirements on the derivatives we employ to hedge our commodity exposure, which would reduce capital available for other purposes.

Consolidation of the Northeast terminal market. In recent years, major U.S. oil companies have disposed of various terminal assets in the Northeast and reduced their participation in wholesale marketing in the region. The key terminals remain in operation as an integral part of the supply chain, though they are generally controlled by other industry participants.

Growth in exploration and production of shale gas has contributed to a relative weakness of domestic natural gas prices compared to competitive refined products in the Northeast, leading to expanded use of natural gas in our marketing area. Natural gas usage in the Northeast has grown substantially, as the supplies of gas from shale formations have grown both in the region (*e.g.*, Marcellus Shale) and the other parts of the United States. Further expansion of domestic natural gas supplies is expected, with consumption in the Northeast also expected to grow as infrastructure developments continue. Moreover, the growth in Marcellus Shale production continues to increase the availability of natural gas in our operating areas. This development is expected to decrease the need for traditional, long-distance sourcing of natural gas supplies using interstate pipeline capacity and natural gas storage capacity. In addition, the potential natural gas supply counterparties in our operating areas are expanding, and there are now some relatively short-term arrangements and additional hedging opportunities available in the Northeast.

Factors that Impact our Business

Our results of operations and financial condition, as well as those of our competitors, will depend in part upon certain economic or industry-wide factors, including the following:

Seasonality and weather conditions. Our financial results are impacted by seasonality in our businesses and are generally better during the winter months, primarily because a material part of our business consists of supplying home heating oil, residual fuel oil and natural gas for space heating purposes during the winter. For example, over the 36-month period ended December 31, 2013, we generated an average of approximately 69% of our total home heating oil and residual fuel oil net sales during the months of November through March. In addition, weather conditions, particularly during these five months, have a significant impact on the demand for our products. Warmer-than-normal temperatures during these months in our areas of operations can decrease the total volume of home heating oil, residual fuel oil and natural gas we sell and the gross margins realized on those sales, whereas colder-than-normal temperatures increase demand for those products and the associated gross margins.

***The impact of the market structure on our hedging strategy*.** We typically hedge our exposure to commodity price moves with NYMEX futures contracts and OTC swaps. In markets where futures prices are higher than spot prices (typically referred to as contango), we generate positive margins when rolling our inventory hedges to successive months. In markets where futures prices are lower than spot prices (typically referred to as backwardation), we realize losses when rolling our inventory hedges to successive months. In backwardated markets, we operate with lower inventory levels and, as a result, have reduced hedging and financing requirements, thereby limiting losses.

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Energy efficiency, new technology and alternative fuels could reduce demand for our products. Increased conservation and technological advances have adversely affected the demand for home heating oil and residual fuel oil. Consumption of residual fuel oil, in particular, has steadily declined in recent years, primarily due to customers converting from other fuels to natural gas, weak industrial demand and tightening of environmental regulations. Use of natural gas is expected to continue to displace other fuels, which we believe will favorably impact our natural gas volumes and margins.

Absolute price increases can lead to reduced demand, increased credit risk, higher interest costs and temporarily reduced margins. Refined product prices have risen due to, among other things, investor interest in using commodities as an inflation hedge, U.S. dollar weakness and supply and demand fundamentals. For example, NYMEX heating oil (HO) contracts have risen from approximately $2.00 per gallon in December 2009 to over $3.00 per gallon in December 2013. As refined product prices rise, we generally experience reduced demand as customers engage in conservation efforts. We also experience a higher level of credit risk from our customers. In addition, our working capital requirements for holding inventory and financing receivables increase with higher price levels, while gross margin levels may stay relatively constant for a period of time due to competitive pressures.

Interest rates could rise. Since mid-2009, the credit markets have been experiencing near-record lows in interest rates. As the overall economy strengthens, it is expected that monetary policy will tighten, resulting in higher interest rates to counter possible inflation. This could affect our ability to access the debt capital markets to the extent we may need, in the future, to fund our growth. In addition, interest rates could be higher than current levels, causing our financing costs to increase accordingly. During the 24 months ended December 31, 2013, we hedged approximately 48% of our floating-rate debt with fixed-for-floating interest rate swaps. Although higher interest rates could limit our ability to raise funds in the debt capital markets, we expect to remain competitive with respect to acquisitions and capital projects, as our competitors would face similar circumstances. As with other yield-oriented securities, our unit price is impacted by the level of our cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank related yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our common units, and a rising interest rate environment could have an adverse impact on our unit price and our ability to issue additional equity to make acquisitions, reduce debt or for other purposes.

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Comparability of our Financial Statements

Our future results of operations may not be comparable to our Predecessor s historical results of operations for the reasons described below.

Our Predecessor s historical results of operations include the results of operations of Kildair, an asphalt and residual fuel oil marketing and commercial trucking business (in which our Predecessor had a 50% interest prior to, and is a consolidated wholly-owned subsidiary as of, October 1, 2012) that was owned by our Predecessor and was not contributed to us in connection with the IPO. From October 2007 through September 30, 2012, the investment in Kildair was accounted for using the equity method of accounting and our Predecessor s share of its results were recorded as equity in net (loss) income of foreign affiliate. The table below provides certain financial information relating to the operations of Kildair, since Kildair s results of operations are included in the financial statements of our Predecessor, but are not part of our assets following the completion of the IPO. Accordingly, Kildair s results of operations are not included in our results of operation beginning October 30, 2013.

	Kildair	
	January 1, 2013 through October 29, 2013	Year Ended December 31, 2012
	(unaudited) ($ in thousands)	
Net Sales	$ 493,708	$ 167,112
Gross Margin	$ 21,570	$ 1,154
Adjusted Gross Margin	$ 21,570	$ 1,154

Our results of operations can be impacted by swings in commodity prices, primarily in refined products and natural gas. We use economic hedges to minimize the impact of changing prices on refined products and natural gas inventory. As a result, commodity price increases at the end of a year can create lower gross margins as the economic hedges, or derivatives, for such inventory may lose value, whereas an increase in the value of such inventory is not recorded for GAAP financial reporting purposes because inventory is recorded at the lower of cost or market.

We believe that SG&A will increase by approximately $2.1 million annually as compared to SG&A incurred for the year ended December 31, 2013 as a result of our becoming a publicly traded partnership. These expenses include increased accounting support services, filing annual and quarterly reports with the SEC, increased audit fees, investor relations, directors fees, directors and officers insurance, legal fees, stock exchange listing fees and registrar and transfer agent fees. Our financial statements for the year ended December 31, 2014 will reflect the impact of these estimated increased expenses, which will affect the comparability of our prior financial statements.

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Results of Operations

The following table presents our volume, net sales, gross margin and adjusted gross margin by segment, as well as our adjusted EBITDA and information on weather conditions, for the years ended December 31, 2013, 2012 and 2011.

	Years Ended December 31,		
	2013	2012	2011
	($ and volumes in thousands)		
Volumes:			
Refined products (gallons)	1,438,967	1,251,852	1,246,728
Natural gas (MMBtus)	51,979	49,417	50,741
Materials handling (short tons)	2,145	2,595	2,425
Materials handling (gallons)	246,708	248,514	265,188
Other operations (short tons)	133	136	151
Net Sales:			
Refined products	$ 4,250,520	$ 3,757,859	$ 3,456,284
Natural gas	304,843	242,006	300,223
Materials handling	28,446	32,536	28,459
Other operations	16,925	11,506	12,461
Total net sales	$ 4,600,734	$ 4,043,907	$ 3,797,427
Gross Margin:			
Refined products	$ 109,324	$ 77,256	$ 105,145
Natural gas	(15,677)	9,191	23,824
Materials handling	28,430	32,320	28,371
Other operations	3,915	2,788	1,370
Total gross margin	$ 125,992	$ 121,555	$ 158,710
Adjusted Gross Margin:			
Refined products	$ 110,172	$ 77,480	$ 97,031
Natural gas	40,373	26,844	22,710
Materials handling	28,430	32,320	28,371
Other operations	3,915	2,788	1,370
Total adjusted gross margin	$ 182,890	$ 139,432	$ 149,482
Calculation of Adjusted Gross Margin:			
Total gross margin	$ 125,992	$ 121,555	$ 158,710
Deduct: total commodity derivative (gains) losses included in net income (loss)(1)	76,203	26,818	34,848
Add: realized commodity derivative gains (losses) included in net income (loss)(1)	(19,305)	(8,941)	(44,076)

Total adjusted gross margin	$ 182,890	$ 139,432	$ 149,482
Reconciliation to Net Income:			
Gross margin	$ 125,992	$ 121,555	$ 158,710
Operating expenses	51,839	47,054	42,414
Selling, general and administrative	53,580	46,449	46,292
Write-off of deferred offering costs(2)		8,931	
Depreciation and amortization	15,452	11,665	10,140
Total operating costs and expenses	120,871	114,099	98,846
Operating income	5,121	7,456	59,864
Gain on acquisition of business		1,512	6,016
Other income (expense)	568	(160)	
Interest income	603	534	755
Interest expense	(28,695)	(23,960)	(24,049)
Income tax (provision) benefit	(5,097)	2,796	(16,636)
Equity in net (loss) income of foreign affiliate		(1,009)	3,622
Net (loss) income	$ (27,500)	$ (12,831)	$ 29,572
Other Data:			
Adjusted EBITDA(3)	$ 73,018	$ 49,781	$ 64,398
Normal heating degree days(4)	6,752	6,787	6,752
Actual heating degree days	6,624	5,803	6,284
Variance from normal heating degree days	(1.9)%	(14.5)%	(6.9)%
Variance from prior period actual heating degree days	14.1%	(7.7)%	2.7%

(1) Both total commodity derivative gains and losses and realized commodity derivative gains and losses include amounts paid to enter into settled contracts.
(2) During the year ended December 31, 2012, we delayed the timing of our public offering and as a result, deferred offering costs of $8.9 million were charged against earnings.
(3) For a discussion of the non-GAAP financial measure adjusted EBITDA, please read Non-GAAP Financial Measures beginning on page 38.
(4) As reported by the NOAA/National Weather Service for the New England oil home heating region over the period of 1981-2011.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

Our results of operations for the year ended December 31, 2013 reflect increasing sales volume, net sales and unit gross margin in our refined products segment, increasing volume and net sales and decreasing unit gross margin in our natural gas segment and decreasing volumes, net sales and gross margin in our materials handling segment.

Adjusted gross margin for the year ended December 31, 2013 reflects increasing adjusted unit gross margin for refined products and natural gas.

	Years Ended December 31,		Increase/(Decrease)	
	2013	2012	$	%
	(in thousands, except unit gross margin and adjusted unit gross margin)			
Volumes:				
Refined products (gallons)	1,438,967	1,251,852	187,115	15%
Natural gas (MMBtus)	51,979	49,417	2,562	5%
Materials handling (short tons)	2,145	2,595	(450)	(17)%
Materials handling (gallons)	246,708	248,514	(1,806)	(1)%
Other operations (short tons)	133	136	(3)	(2)%
Net Sales:				
Refined products	$ 4,250,520	$ 3,757,859	$ 492,661	13%
Natural gas	304,843	242,006	62,837	26%
Materials handling	28,446	32,536	(4,090)	(13)%
Other operations	16,925	11,506	5,419	47%
Total net sales	$ 4,600,734	$ 4,043,907	$ 556,827	14%
Gross Margin:				
Refined products	$ 109,324	$ 77,256	$ 32,068	42%
Natural gas	(15,677)	9,191	(24,868)	(271)%
Materials handling	28,430	32,320	(3,890)	(12)%
Other operations	3,915	2,788	1,127	40%
Total gross margin	$ 125,992	$ 121,555	$ 4,437	4%

Unit Gross Margin:							
Refined products	$	0.076	$	0.062	$	0.014	23%
Natural gas	$	(0.302)	$	0.186	$	(0.488)	(262)%
Adjusted Gross Margin:							
Refined products	$	110,172	$	77,480	$	32,692	42%
Natural gas		40,373		26,844		13,529	50%
Materials handling		28,430		32,320		(3,890)	(12)%
Other operations		3,915		2,788		1,127	40%
Total adjusted gross margin	$	182,890	$	139,432	$	43,458	31%
Adjusted Unit Gross Margin:							
Refined products	$	0.077	$	0.062	$	0.015	24%
Natural gas	$	0.777	$	0.543	$	0.234	43%

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Refined Products

Refined products net sales were $4.3 billion and $3.8 billion for the years ended December 31, 2013 and 2012, respectively. Excluding Kildair s net sales of $485.0 million and $164.5 million, respectively, the refined products net sales increased $172.1 million, or 5%, which was driven primarily by higher refined products sales volumes. Excluding Kildair s sales volumes of 204.8 million gallons and 106.2 million gallons, respectively, refined products sales volumes were 1.2 billion gallons and 1.1 billion gallons, respectively. Distillate sales volumes increased 117.1 million gallons, or 14%, period over period, with higher volumes in all four quarters during 2013. The percentage increases were highest in the three months ending March 31, 2013 compared to the same period in 2012, with a key factor being the unseasonably warm weather during that time period in 2012. Gasoline sales volumes decreased by approximately 32.1 million gallons, or 12%, for the year ended December 31, 2013 as compared to the same period in 2012. This decrease occurred primarily due to aggressive pricing by our competitors. Residual fuel oil sales volumes increased 3.6 million gallons, or 5%, for the year ended December 31, 2013 as compared to the same period in 2012. The average refined products selling price per gallon was 3% lower for the year ended December 31, 2013 as compared to the same period in 2012.

Excluding Kildair s gross margin of $19.3 million and $0.5 million, respectively, refined products gross margin was $90.1 million and $76.8 million for the years ended December 31, 2013 and 2012, respectively. Refined products adjusted gross margin, exclusive of Kildair, was $90.9 million and $77.0 million for the years ended December 31, 2013 and 2012, respectively. For the years ended December 31, 2013 and 2012, refined products adjusted gross margin was $0.8 million and $0.2 million higher, respectively, than refined products gross margin due to changes in the difference between refined products total commodity derivative gains and losses and refined products realized commodity derivative gains and losses, respectively.

Excluding Kildair, the refined products adjusted gross margin increase of $13.9 million, or 18%, was primarily due to improved returns in distillates, in particular heating oil. Heating oil volumes and unit margins both improved substantially, partly due to the colder weather conditions in 2013. The reinstatement of the federal bio-fuel excise tax credits in January 2013 contributed $5.0 million to the increase. These increases were somewhat offset by one-time basis losses associated with the transition of the NYMEX HO futures contract to ULSD specifications starting with the May 2013 contract.

Natural Gas

Natural gas net sales were $304.8 million and $242.0 million for the years ended December 31, 2013 and 2012, respectively. The natural gas sales increase of $62.8 million, or 26%, was driven by higher commodity prices as the average natural gas marketing price per MMBtu was approximately 20% higher during the year ended December 31, 2013 as compared to the same period in 2012. The stronger natural gas price environment was due in part to the higher weather-driven demand during 2013. Natural gas sales volumes increased 5% for the year ended December 31, 2013 as compared to the same period in 2012, with the colder weather being a contributing factor.

Natural gas gross margin was $(15.7) million and $9.2 million for the years ended December 31, 2013 and 2012, respectively. Natural gas adjusted gross margin was $40.4 million and $26.8 million for the years ended December 31, 2013 and 2012, respectively. Natural gas adjusted gross margin was $56.1 million higher than natural gas gross margin for the year ended December 31, 2013 and $17.6 million higher than natural gas gross margin for the year ended December 31, 2012 due to changes in the difference between natural gas total commodity derivative gains and losses and natural gas realized commodity derivative gains and losses.

The natural gas adjusted gross margin increase of $13.5 million, or 50%, was due to a number of factors including higher sales volumes partly driven by the colder weather conditions, the continuing transition of our customer base towards smaller commercial and industrial end users, and additional margin generation due to optimization of transportation assets and storage utilization. The transportation/storage optimization opportunities were most notable during the volatile pricing periods observed during the winter months.

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Materials Handling

Materials handling net sales were $28.4 million and $32.5 million for the years ended December 31, 2013 and 2012, respectively. The materials handling net sales decrease of $4.1 million, or 13%, was primarily due to a decrease in dry bulk activities including salt, gypsum and petcoke. In addition, windmill component handling activities were substantially lower in the year ended December 31, 2013 compared to the same period in 2012. These decreases were partially offset by increased asphalt handling revenues over the same time periods due primarily to increased volumes by a major customer.

The materials handling gross margin decrease of $3.9 million, or 12%, was primarily due to a reduction in dry bulk activities including salt, gypsum, windmill component handling, and petcoke, generally reflecting the timing requirements of our customers.

Other Operations

Sales from our other operations were $16.9 million and $11.5 million for the years ended December 31, 2013 and 2012, respectively, representing an increase of $5.4 million. Of this increase, $6.1 million was due to the commercial trucking activities of Kildair.

Gross margins from our other operations were $3.9 million and $2.8 million for the years ended December 31, 2013 and 2012, respectively, representing an increase of $1.1 million. Of this increase, $1.6 million was due to the commercial trucking activities of Kildair.

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Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

Our results of operations for the year ended December 31, 2012 reflect increasing sales volume and net sales and decreasing unit gross margin in our refined products segment, declining volume, net sales and unit gross margin in our natural gas segment and decreasing volumes and increasing net sales and gross margin in our materials handling segment.

Adjusted gross margin for the year ended December 31, 2012 reflects decreasing adjusted unit gross margin for refined products and increasing adjusted unit gross margin for natural gas.

	Years Ended December 31,		Increase/(Decrease)	
	2012	2011	$	%
	(in thousands, except unit gross margin and adjusted unit gross margin)			
Volumes:				
Refined products (gallons)	1,251,852	1,246,728	5,124	*
Natural gas (MMBtus)	49,417	50,741	(1,324)	(3)%
Materials handling (short tons)	2,595	2,425	170	7%
Materials handling (gallons)	248,514	265,188	(16,674)	(6)%
Other operations (short tons)	136	151	(15)	(10)%
Net Sales:				
Refined products	$ 3,757,859	$ 3,456,284	$ 301,575	9%
Natural gas	242,006	300,223	(58,217)	(19)%
Materials handling	32,536	28,459	4,077	14%
Other operations	11,506	12,461	(955)	(8)%
Total net sales	$ 4,043,907	$ 3,797,427	$ 246,480	6%
Gross Margin:				
Refined products	$ 77,256	$ 105,145	$ (27,889)	(27)%
Natural gas	9,191	23,824	(14,633)	(61)%
Materials handling	32,320	28,371	3,949	14%
Other operations	2,788	1,370	1,418	104%
Total gross margin	$ 121,555	$ 158,710	$ (37,155)	(23)%
Unit Gross Margin:				
Refined products	$ 0.062	$ 0.084	$ (0.022)	(26)%
Natural gas	$ 0.186	$ 0.470	$ (0.284)	(60)%
Adjusted Gross Margin:				
Refined products	$ 77,480	$ 97,031	$ (19,551)	(20)%
Natural gas	26,844	22,710	4,134	18%
Materials handling	32,320	28,371	3,949	14%

Other operations	2,788	1,370	1,418	104%
Total adjusted gross margin	$ 139,432	$ 149,482	$ (10,050)	(7)%
Adjusted Unit Gross Margin:				
Refined products	$ 0.062	$ 0.078	$ (0.016)	(21)%
Natural gas	$ 0.543	$ 0.448	$ 0.095	21%

* Not meaningful

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Refined Products

Refined products net sales were $3.8 billion and $3.5 billion for the years ended December 31, 2012 and 2011, respectively. Excluding the non-contributed Canadian operations net sales of $164.5 million for the year ended December 31, 2012, the refined products net sales increase of $137.1 million, or 4%, was driven primarily by higher refined products commodity prices. The average refined product price per gallon was approximately 8% higher during the year ended December 31, 2012 as compared to the same period in 2011. This increase was partially offset by decreased refined products sales volumes. Excluding the non-contributed Canadian operations sales volumes of 106.2 million gallons for the year ended December 31, 2012, refined products sales volumes were 1.1 billion gallons and 1.2 billion gallons for the years ended December 31, 2012 and 2011, respectively. Distillate demand decreased 10% period over period resulting in a decrease of 95.1 million gallons of distillate oil sales volumes for the year ended December 31, 2012 as compared to the same period in 2011. The distillate sales volume reduction was mostly due to a decline in diesel sales volume, though heating oil and other distillate sales volumes were also lower. The lower diesel sales volume was largely due to the loss of a large transit contract, with some other smaller contract reductions also contributing to the reduction. The lower heating oil sales volume was a result of the much milder weather conditions, particularly in the three months ended March 31, 2012, with heating degree days 8% lower for the year ended December 31, 2012 as compared to the same period in 2011. Although heating oil sales volumes were lower, the percentage reduction was less than the drop in degree days. Residual fuel oil sales volumes decreased approximately 11.0 million gallons, or 14%, for the year ended December 31, 2012 as compared to the same period in 2011 with key factors including conversion of a large customer to LNG, other boiler conversions to natural gas and biomass, and the warmer weather conditions. Gasoline sales volumes increased by approximately 5.0 million gallons, or 2%, for the year ended December 31, 2012 as compared to the same period in 2011, primarily due to increased contractual sales volumes associated with government accounts.

Excluding the non-contributed Canadian operations gross margin of $0.5 million for the year ended December 31, 2012, refined products gross margin was $76.8 million and $105.1 million for the years ended December 31, 2012 and 2011, respectively. Excluding the non-contributed Canadian operations adjusted gross margin of $0.5 million for the year ended December 31, 2012, refined products adjusted gross margin was $77.0 million and $97.0 million for the year ended December 31, 2012 and 2011, respectively. For the years ended December 31, 2012 and 2011, refined products adjusted gross margin was $0.2 million higher than refined products gross margin and $8.1 million lower than refined products gross margin due to changes in the difference between refined products total commodity derivative gains and losses and refined products realized commodity derivative gains and losses, respectively.

The refined products adjusted gross margin decrease of $20.0 million, or 21%, was primarily due to lower adjusted unit gross margins which reduced adjusted gross margin by $12.2 million, and lower refined products sales volumes which reduced adjusted gross margin by $7.8 million, in each case as compared to the same period in 2011. The primary factor in the decline in the refined products adjusted gross margin in 2012 compared to 2011 was the deteriorating market structure to hold distillate inventory. During 2012 the average distillate market structure as measured by the difference in the prompt and second month NYMEX heating oil prices was essentially flat, providing limited opportunity to benefit from holding inventory. In 2011, this price difference averaged nearly $0.01/gallon in contango, providing more opportunity to benefit from carrying hedged inventory. In addition to the lower adjusted gross margin opportunities due to the market structure, refined products marketing adjusted gross margin contribution was also lower for distillates, with increased adjusted unit gross margin only partially offsetting the reduced sales volumes. Gasoline marketing adjusted gross margin contribution essentially offset the decline in distillate marketing adjusted gross margin, due to gains in both sales volume and unit margins for the year ended December 31, 2012 as compared to the same period in 2011. Heavy oil adjusted gross margin was comparable for the years ended December 31, 2012 and 2011.

Natural Gas

Natural gas net sales were $242.0 million and $300.2 million for the years ended December 31, 2012 and 2011, respectively. The natural gas net sales decrease of $58.2 million, or 19%, was driven primarily by lower commodity prices as the average natural gas marketing price per MMBtu was approximately 17% lower during the year ended December 31, 2012 as compared to the same period in 2011. The weaker natural gas price environment was due in part to the growing domestic supplies of natural gas. In addition, natural gas sales volumes decreased 3% for the year ended December 31, 2012 as compared to the same period in 2011, due to the milder weather experienced in the three months ended March 31, 2012.

Natural gas gross margin was $9.2 million and $23.8 million for the years ended December 31, 2012 and 2011, respectively. Natural gas adjusted gross margin was $26.8 million and $22.7 million for the years ended December 31, 2012 and 2011, respectively. For the years ended December 31, 2012 and 2011, natural gas adjusted gross margin was $17.7 million higher than natural gas gross margin and $1.1 million lower than natural gas gross margin due to changes in the difference between natural gas total commodity derivative gains and losses and natural gas realized commodity derivative gains and losses, respectively.

The natural gas adjusted gross margin increase of $4.1 million, or 18%, was driven primarily by an increase in adjusted unit gross margins which increased adjusted gross margin by $4.7 million, and lower natural gas sales volume which reduced adjusted gross margin by $0.6 million, in each case for the year ended December 31, 2012 as compared to the same period in 2011. The increase in natural gas adjusted unit gross margin was primarily driven by optimization opportunities associated with third party pipeline capacity that was under Sprague s operating control.

Materials Handling

Materials handling net sales were $32.5 million and $28.5 million for the years ended December 31, 2012 and 2011, respectively. The materials handling net sales increase of $4.1 million, or 14%, is primarily due to an increase in materials handling net sales in dry bulk activities including salt, gypsum and petcoke for the year ended December 31, 2012 as compared to the same period in 2011.

Materials handling gross margin was $32.3 million and $28.4 million for the years ended December 31, 2012 and 2011, respectively. Similar to the materials handling net sales, the materials handling gross margin increase of $3.9 million, or 14%, was primarily due to an increase in materials handling net sales in dry bulk activities including salt, gypsum and petcoke for the year ended December 31, 2012 as compared to the same period in 2011.

Other Operations

Net sales from our other operations were $11.5 million and $12.5 million for the years ended December 31, 2012 and 2011, respectively representing an overall decrease of $1.0 million, or 8%. Net sales from our other operations increased by $2.6 million due to the commercial trucking activities of Kildair, our Canadian subsidiary that was fully consolidated beginning October 1, 2012, and decreased by $3.6 million, or 29%, due to lower coal marketing net sales. Coal marketing net sales decreased due both to a decrease in coal commodity prices and a reduction in coal marketing sales volumes of 10% for the year ended December 31, 2012 as compared to the same period in 2011.

Gross margin from our other operations were $2.8 million and $1.4 million for the year ended December 31, 2012 and 2011, respectively, representing an increase of $1.4 million, or 104%. Of the $1.4 million increase, $0.7 million was due to the commercial trucking activities of Kildair, our Canadian subsidiary that was fully consolidated beginning October 1, 2012, and $0.7 million was due to stronger coal marketing unit gross margins for the year ended December 31, 2012 as compared to the prior year.

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Operating Costs and Expenses

The following table presents our operating expenses and selling, general and administrative expenses for the years ended December 31, 2013, 2012, and 2011.

	Years Ended December 31,		
		Predecessor	Predecessor
	2013	2012	2011
		($ in thousands)	
Operating expenses	$ 51,839	$ 47,054	$ 42,414
Selling, general and administrative expenses	$ 53,580	$ 46,449	$ 46,292
Write-off of deferred offering costs	$	$ 8,931	$
Depreciation and amortization	$ 15,452	$ 11,665	$ 10,140

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

	Years Ended December 31,		Increase/(Decrease)	
		Predecessor		
	2013	2012	$	%
		($ in thousands)		
Operating expenses	$ 51,839	$ 47,054	$ 4,785	10%
Selling, general and administrative expenses	$ 53,580	$ 46,449	$ 7,131	15%
Write-off of deferred offering costs	$	$ 8,931	$ (8,931)	*
Depreciation and amortization	$ 15,452	$ 11,665	$ 3,787	32%

* Not meaningful

Operating Expenses. Operating expenses for the year ended December 31, 2013 increased $4.8 million, or 10%, as compared to the year ended December 31, 2012, primarily due to the inclusion of $8.8 million and $3.3 million of Kildair s operating expenses for the years ended December 31, 2013 and 2012, respectively, representing an increase of $5.5 million. The remaining operating expenses decrease of $0.7 million was primarily related to a decrease of $1.6 million due to lower costs associated with fees related to materials handling operations offset by an increase of $1.2 million primarily due to the operating expenses of our Bridgeport terminal, which was acquired on July 31, 2013.

Selling, General and Administrative Expenses. Selling, general and administrative expenses for the year ended December 31, 2013 increased $7.1 million, or 15%, as compared to the year ended December 31, 2012. Selling, general and administrative expenses include Kildair s expenses of $4.3 million and $1.2 million for the years ended December 31, 2013 and 2012, respectively, representing an increase of $3.1 million. The remaining increase in selling, general and administrative expenses was primarily due to discretionary incentive compensation as a result of higher earnings performance.

Depreciation and Amortization. Depreciation and amortization for the year ended December 31, 2013 increased $3.8 million, or 32%, as compared to the year ended December 31, 2012. Kildair s depreciation and amortization expense was $5.8 million and $1.8 million for the years ended December 31, 2013 and 2012, respectively, representing an increase of $4.0 million.

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Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

	Years Ended December 31, Predecessor 2012	Predecessor 2011	Increase/(Decrease) $	%
	($ in thousands)			
Operating expenses	$ 47,054	$ 42,414	$ 4,640	11%
Selling, general and administrative expenses	$ 46,449	$ 46,292	$ 157	*
Write-off of deferred offering costs	$ 8,931		$ 8,931	*
Depreciation and amortization	$ 11,665	$ 10,140	$ 1,525	15%

* Not meaningful

Operating Expenses. Operating expenses for the year ended December 31, 2012 increased $4.6 million, or 11%, as compared to the year ended December 31, 2011. Of this increase, $3.3 million was related to Kildair s operating expenses which consisted primarily of terminal and trucking salaries and benefits, maintenance, utilities and other costs and $1.4 million was attributed to additional stockpile expenses due to increased material handling activity.

Selling, General and Administrative Expenses. Selling, general and administrative expenses for the year ended December 31, 2012 increased $0.2 million, or less than 1%, as compared to the year ended December 31, 2011. Selling, general and administrative expenses for the year ended December 31, 2012 included approximately $1.2 million related to Kildair which consisted primarily of salaries and benefits, insurance and other expenses. Other changes included an increase of salaries and related costs of $1.8 million primarily offset by a decrease of $3.2 million of discretionary incentive compensation.

Write-off of Deferred Offering Costs. During the year ended December 31, 2012, deferred offering costs of $8.9 million were charged against earnings due to an extended delay in the timing of our IPO. The total charge included $6.5 million of offering costs previously deferred as of December 31, 2011 and $2.4 million of deferred offering costs incurred during the year ended December 31, 2012.

Depreciation and Amortization. Depreciation and amortization for the year ended December 31, 2012 increased $1.5 million, or 15%, as compared to the year ended December 31, 2011. Of this increase $1.8 million was due to Kildair s depreciation and amortization. Kildair s operating results are fully consolidated beginning October 1, 2012.

Interest Expense, Net, Equity in Net (Loss) Income of Foreign Affiliate and Gain on Acquisition of Business

The following table presents our interest expense, net, equity in net (loss) income of foreign affiliate and gain on acquisition of business for the years ended December 31, 2013, 2012, and 2011.

	Years Ended December 31, 2013	Predecessor 2012	Predecessor 2011
		($ in thousands)	
Interest expense, net	$ 28,092	$ 23,426	$ 23,294

Equity in net (loss) income of foreign affiliate	$		$	(1,009)	$	3,622
Gain on acquisition of business	$		$	1,512	$	6,016

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Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

	Years Ended December 31, 2013	Predecessor 2012	Increase/(Decrease) $	%
	($ in thousands)			
Interest expense, net	$ 28,092	$ 23,426	$ 4,666	20%
Equity in net (loss) income of foreign affiliate	$	$ (1,009)	$ 1,009	*
Gain on acquisition of business	$	$ 1,512	$ (1,512)	*

* Not meaningful

Interest Expense, net. Interest expense, net for the year ended December 31, 2013 increased $4.7 million, or 20%, as compared to the year ended December 31, 2012. Interest expense included Kildair s expenses of $3.0 million and $1.1 million for the years ended December 31, 2013 and 2012, respectively, representing an increase of $1.9 million. The remaining increase in interest expense of $2.8 million was primarily due to higher average acquisition related borrowings and increased amortization of debt issuance costs associated with the Partnership s new credit facility.

Equity in Net (Loss) Income of Foreign Affiliate. The equity in net loss of our Predecessor s foreign affiliate for the year ended December 31, 2012, was $1.0 million. For the year ended December 30, 2011 and through September 30, 2012, we recorded the activity of Kildair as an equity investment in a foreign affiliate. Kildair was fully consolidated by our Predecessor beginning on October 1, 2012.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

	Years Ended December 31, Predecessor 2012	Predecessor 2011	Increase/(Decrease) $	%
	($ in thousands)			
Interest expense, net	$ 23,426	$ 23,294	$ 132	1%
Equity in net (loss) income of foreign affiliate	$ (1,009)	$ 3,622	$ (4,631)	(128)%
Gain on acquisition of business	$ 1,512	$ 6,016	$ (4,504)	(75)%

* Not meaningful

Interest Expense, net. Interest expense, net for the year ended December 31, 2012 increased $0.1 million, or 1%. Interest expense, net included an increase of approximately $1.2 million related to Kildair which was fully consolidated beginning October 1, 2012, and increased interest expense of $0.6 million due to higher average borrowings under our acquisition facility, and approximately $1.7 million in increased fees and other costs, offset by a reduction in interest expense of approximately $3.4 million primarily due to decreased borrowing levels as a result of lower average inventory levels in 2012 as compared to the same period in 2011.

Equity in Net (Loss) Income of Foreign Affiliate. The equity in earnings in our foreign affiliate for the year ended December 31, 2012 was a loss of $1.0 million as compared to net income of $3.6 million for the year ending

December 31, 2011. The equity in earnings in our foreign affiliate for the year ended December 31, 2012 represents the equity in earnings through September 30, 2012, prior to full consolidation of the operating results beginning on October 1, 2012. Equity in earnings for this period decreased due to basis losses on residual oil hedge positions and lower margins associated with residual fuel oil sales as compared to the year ended December 31, 2011.

Gain on Acquisition of Business. During the year ended December 31, 2012, we recognized a gain of $1.5 million as a result of re-measuring to fair value our 50% equity interest in Kildair before the business combination in which we acquired the remaining 50% of the equity interest in Kildair. The gain was calculated as the difference between the acquisition-date fair value ($57.0 million) and the book value immediately prior to the acquisition date ($55.5 million). The fair value was determined using valuation techniques including the discounted cash flow approach and the market multiple approach (enterprise value of earnings before interest, taxes, depreciation and amortization). The discounted cash flow approach incorporated assumptions including estimated future cash flows and a discount rate that reflects consideration of risk free rates as well as market risk and is a Level 3 measure.

During the year ended December 31, 2011, we recorded a gain in connection with the purchase of an oil terminal in Rensselaer, New York for $3.4 million. In addition, we purchased approximately $4.4 million of inventory that was stored at the terminal. The fair value of the identifiable assets acquired was $13.9 million which exceeded the purchase price. As a result, we reassessed the identification, recognition and measurement of the identifiable assets and concluded that the valuation procedures and resulting Level 3 measures were appropriate. Accordingly, we recognized a gain of $6.0 million associated with the acquisition. We believe that we were able to acquire the terminal for less than fair value of its assets because of the seller s strategic intent to exit a non-core business operation.

Liquidity and Capital Resources

Liquidity

Our primary liquidity needs are to fund our working capital requirements, operating expenses, capital expenditures and quarterly distributions. Cash generated from operations, our borrowing capacity under the credit agreement and potential future issuances of additional partnership interests or debt securities are our primary sources of liquidity. At December 31, 2013, the Partnership had net working capital of approximately $211.4 million.

In connection with the closing of the IPO, we entered into a credit agreement that matures on October 30, 2018 and consists of two revolving credit facilities: (1) a $750.0 million working capital facility and (2) a $250.0 million acquisition facility.

At December 31, 2013, under our working capital facility, the Partnership had outstanding borrowings of approximately $351.6 million and approximately $73.4 million of outstanding letters of credit. As of December 31, 2013, the working capital facility borrowing base was approximately $573.8 million, providing us with approximately $148.8 million in undrawn borrowing capacity. As of December 31, 2013, the Partnership had approximately $107.9 million in outstanding borrowings under our acquisition facility, providing us with approximately $142.1 million in undrawn borrowing capacity under the acquisition facility.

We enter our seasonal peak period during the fourth quarter of each year, during which inventory, accounts receivable and debt levels increase. As we move out of the winter season at the end of the first quarter of the following year, inventory is reduced, accounts receivable are collected and converted into cash and debt is paid down. During the twelve months ended December 31, 2013, the amount drawn under the working capital facility of our credit agreements fluctuated from a low of approximately $176.8 million to a high of approximately $399.6 million.

We believe that we will have sufficient liquid assets, cash flow from operations and borrowing capacity under our credit agreement to meet our financial commitments, debt service obligations, contingencies and anticipated capital expenditures. However, we are subject to business and operational risks that could adversely affect our cash flow. A material decrease in our cash flow would likely have an adverse effect on our ability to meet our financial commitments and debt service obligations.

Certain of our trade credit providers have historically required us to obtain trade credit support from Axel Johnson, and Axel Johnson has provided us with such support for our operations. As of December 31, 2013, Axel

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Johnson provided us with approximately $80.2 million of outstanding trade credit support. We believe that we will be able to work with our trade creditors to reduce, and eventually eliminate, the need for trade credit support from Axel Johnson. Pursuant to the omnibus agreement that we entered into in connection with the closing of the IPO, we agreed to use our commercially reasonable efforts to reduce, and eventually eliminate, the need for trade credit support from Axel Johnson. In order to assist us with a smooth transition with our trade credit providers following the completion of the IPO, pursuant to such omnibus agreement, Axel Johnson agreed to provide us with trade credit support, consistent with past practice, through December 31, 2016, if and to the extent such trade credit support is necessary in our reasonable judgment. We believe that the elimination of trade credit support from Axel Johnson after December 31, 2016 will not have a material adverse effect on our operations.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements.

Capital Expenditures

Our terminals require investments to expand, upgrade or enhance existing assets and to comply with environmental and operational regulations. Our capital requirements primarily consist of maintenance capital expenditures and expansion capital expenditures. Maintenance capital expenditures represent capital expenditures made to replace assets, or to maintain the long-term operating capacity of our assets or operating income. Examples of maintenance capital expenditures are expenditures required to maintain equipment reliability, terminal integrity and safety and to address environmental laws and regulations. Costs for repairs and minor renewals to maintain facilities in operating condition and that do not extend the useful life of existing assets will be treated as maintenance expenses as we incur them. Expansion capital expenditures are capital expenditures made to increase the long-term operating capacity of our assets or our operating income whether through construction or acquisition of additional assets. Examples of expansion capital expenditures include the acquisition of equipment and the development or acquisition of additional storage capacity, to the extent such capital expenditures are expected to expand our operating capacity or our operating income.

During the year ended December 31, 2013, we spent a total of approximately $7.4 million for maintenance capital expenditures, of which $1.4 million was incurred by Kildair, and we spent $14.7 million for expansion and/or upgrades of our terminals, of which $13.3 million was incurred by Kildair primarily related to a crude storage and handling construction project. We anticipate that future maintenance capital expenditures will be funded with cash generated by operations and that future expansion capital requirements will be provided through long-term borrowings or other debt financings and/or equity offerings.

Contractual Obligations

We have contractual obligations that are required to be settled in cash. The amounts of our contractual obligations at December 31, 2013 were as follows:

	Payments due by period				
	Total	Less than 1 year	1-3 years	4-5 years	More than 5 years
	($ in thousands)				
Operating lease obligations(1)	$ 27,368	$ 6,227	$ 13,783	$ 900	$ 6,458

Capital lease obligations (including interest)	$ 4,785	$ 426	$ 1,278	$ 852	$ 2,229
Credit facilities (including interest)(2)	$ 514,401	$ 44,137	$ 127,266	$ 342,998	$
Product purchases(3)	$ 685,532	$ 681,090	$ 4,442	$	$
Transportation and storage(4)	$ 17,597	$ 8,760	$ 7,078	$ 1,594	$ 165
Total	$ 1,249,683	$ 740,640	$ 153,847	$ 346,344	$ 8,852

(1) We have leases for a refined products terminal, refined products storage, maritime charters, vehicles, office and plant facilities, computer and other equipment that are accounted for as operating leases.

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(2) Amounts include principal and interest on our working capital revolving credit facility and our acquisition line revolving credit facility at December 31, 2013. The credit agreement has a contractual maturity of October 2018 and no principal payments are required prior to that date. However, we repay amounts outstanding and borrow funds based on our working capital requirements. Therefore, the current portion of the working capital revolving credit facility included in our consolidated balance sheets is the amount we expect to pay down during the course of the year, and the long-term portion of the working capital revolving credit facility is the amount we expect to be outstanding during the entire year. Interest is calculated using the rates in effect as of December 31, 2013, and we assume a ratable payment of the current portion of the working capital revolving credit facility through the expiration date.

(3) Product purchases include estimated purchase commitments for refined products and natural gas. The value of these future supply commitments, if not fixed in price, will fluctuate based on prevailing market prices. The prices at which we purchase refined products and natural gas are determined by reference to published market prices prevailing at the time of purchase. The value of our product purchase commitments were computed based on contractual prices.

(4) Transportation and storage commitments include refined products throughput agreements at third-party terminals and natural gas pipeline transportation and storage agreements that have minimum usage requirements.

Cash Flows

	Years Ended December 31,		
		Predecessor	
	2013	2012	2011
		(in thousands)	
Net cash (used in) provided by operating activities	$ (79,455)	$ 163,129	$ (43,861)
Net cash used in investing activities	$ (40,740)	$ (79,693)	$ (17,004)
Net cash provided by (used in) financing activities	$ 117,634	$ (111,560)	$ 88,882

Years Ended December 31, 2013, December 31, 2012 and December 31, 2011

Operating Activities

Net cash used in operating activities for the year ended December 31, 2013 was approximately $79.5 million which included a reduction of cash flow of $172.1 million related to accounts receivable which primarily was the result of a $130.2 million distribution of accounts receivable to Sprague Holdings and the contribution of Kildair s accounts receivable as of October 30, 2013 of $48.3 million to an affiliate of Sprague Holdings both of which occurred in connection with the initial public offering. These distributions of accounts receivable had a negative impact on cash flow from operations since they represented current year operating activity that was transferred prior to the point when cash was collected. This was partially offset by a reduction of $57.8 million in inventory, primarily related to the colder weather experienced in the latter portion of 2013 as compared to 2012. Cash flow from operations was favorably impacted by a decrease of $50.8 million in derivative instruments relating to less customer demand for locking in fixed price forward commitments.

Net cash provided by operating activities for the year ended December 31, 2012 was approximately $163.1 million and was driven by a decrease of $54.4 million in inventory relating to a weak market structure in heating oil and residual fuel oil and warm weather conditions impacting customer demand, an increase of $32.5 million in accounts payable and accrued liabilities, primarily due to timing of invoice payments for product purchases, a decrease of $24.2 million in account receivable, and a decrease of $27.2 million in derivative instruments relating to lower customer demand for locking in fixed price forward commitments and was partially offset by a net loss of $12.8 million.

Net cash used in operating activities for the year ended December 31, 2011 was approximately $43.9 million and was driven by an increase of $73.3 million in inventory, and an increase of $39.7 million in derivative instruments relating to higher commodity prices. This was partially offset by net income of

$29.6 million, a decrease of $19.2 million in accounts receivable primarily related to lower sales volumes, and an increase of $10.7 million in accounts payable and accrued liabilities, primarily due to timing of invoice payments for product purchases.

Investing Activities

Net cash used in investing activities for the year ended December 31, 2013 was approximately $40.7 million and consisted primarily of $20.7 million related to the purchase of the Bridgeport terminal, $13.3 million related to expansion capital expenditures at Kildair for the crude oil storage and handling construction project and $8.8 million relating to capital expenditure projects across our terminal system.

Net cash used in investing activities for the year ended December 31, 2012 was approximately $79.7 million and consisted primarily of $73.0 million related to our acquisition on October 1, 2012 of the remaining 50% of Kildair, and $7.3 million related to capital expenditure projects across our terminal system.

Net cash used in investing activities for the year ended December 31, 2011 was approximately $17.0 million and consisted primarily of $7.8 million related to our acquisition of a refined products terminal located in Rensselaer, New York, $7.3 million related to capital expenditure projects across our terminal system, and an advance to our foreign affiliate of approximately $2.0 under a note agreement.

Financing Activities

Net cash provided by financing activities for the year ended December 31, 2013 was approximately $117.6 million. During 2013, the net cash provided by financing activities primarily resulted from $140.3 million in net proceeds (net of underwriting and structuring fees and other offering expenses) from our IPO, net borrowings of $34.6 million under our credit agreement partially offset by a distribution of $40.0 million paid to Axel Johnson and debt issuance costs of $13.7 million.

Net cash used in financing activities for the year ended December 31, 2012 was approximately $111.6 million. During 2012, the net cash used in financing activities primarily resulted from $107.8 million of net payments under the credit agreement and a $26.9 million dividend to Axel Johnson partially offset by borrowings of $25.0 million from a third party relating to the financing of the remaining 50% purchase of Kildair s equity.

Net cash provided by financing activities for the year ended December 31, 2011 was approximately $88.9 million. During 2011, the net cash provided by financing activities primarily resulted from $116.3 million of net borrowings under the credit agreement, offset by a $26.0 million distribution to Axel Johnson.

Credit Agreement

In connection with the closing of our IPO on October 30, 2013, we entered into a new revolving credit agreement (the credit agreement) having the principal terms described below.

There are two revolving credit facilities under our credit agreement:

A working capital facility of up to $750.0 million to be used for working capital loans and letters of credit in the principal amount equal to the lesser of our borrowing base and $750.0 million. Our borrowing base is calculated as the sum of specified percentages of eligible cash collateral, eligible billed and unbilled accounts receivable, eligible inventory and other approved categories. Subject to certain conditions, the working capital facility may be increased by up to $200.0 million.

An acquisition facility of up to $250.0 million to be used for loans and letters of credit to fund capital expenditures and acquisitions related to our current businesses. Loans and letters of credit outstanding under the acquisition facility generally cannot exceed 65% of the fair market value of all of our appraised fixed assets. Subject to certain conditions, the acquisition facility may be increased by up to $200.0 million. We and each of our subsidiaries, if not the borrower, are guarantors of all obligations under the credit agreement. All obligations under our credit agreement are secured by substantially all of our assets and substantially all of the assets of our subsidiaries.

Indebtedness under our credit agreement bears interest, at our option, at a rate per annum equal to either the Eurodollar Rate (which means the LIBOR Rate) for interest periods of one, two, three or six months plus a specified margin or an Alternate Base Rate plus a specified margin. The Alternate Base Rate is the highest of (a) the prime rate of interest announced from time to time by the agent bank as its Base Rate (b) 0.50% per annum above the Federal Funds rate as in effect from time to time and (c) the Eurodollar Rate for 1-month LIBOR as in effect from time to time plus 1.00% per annum.

The specified margin for the working capital facility under our credit agreement ranges from 1.00% to 1.50% for loans bearing interest at the Alternate Base Rate and from 2.00% to 2.50% for loans bearing interest at the Eurodollar Rate and for letters of credit issued under the working capital facility. The specified margin is calculated based upon how much of the working capital facility we utilize. In addition, we incur a commitment fee based on the unused portion of the working capital facility at a rate ranging from 0.375% to 0.50% per annum.

The specified margin for the acquisition facility under our credit agreement ranges from 2.00% to 2.25% for loans bearing interest at the Alternate Base Rate, and from 3.00% to 3.25% for loans bearing interest at the Eurodollar Rate and for letters of credit issued under the acquisition facility. In addition, we incur a commitment fee on the unused portion of the acquisition facility at a rate ranging from 0.375% to 0.50% per annum. The specified margin and the commitment fee for the acquisition facility is calculated quarterly based upon our consolidated total leverage ratio.

Our credit agreement matures in October 2018, at which point all amounts outstanding under the working capital facility and acquisition facility will become due. We are required to make prepayments under our credit agreement at any time when the aggregate amount of the outstanding loans and letters of credit under the working capital facility exceeds the aggregate amount of commitments in respect of such facility, or when the aggregate amount of outstanding loans and letters of credit under the acquisition facility exceeds the lesser of the aggregate amount of commitments in respect of such facility and 65% of the fair market value of the appraised assets, or, from the period of August 1st to March 31st each year, when the aggregate amount of the outstanding loans and letters of credit under the working capital facility plus the aggregate amount of working capital loans and letters of credit under the acquisition facility exceed the borrowing base. Mandatory prepayments also are required for certain sales of our assets. All loans repaid or prepaid may be reborrowed prior to the maturity date subject to satisfaction of the applicable conditions at the time of borrowing.

Our credit agreement prohibits us from making distributions to unitholders if any event of default, as defined in our credit agreement, occurs or would result from the distribution. In addition, our credit agreement contains various covenants that may limit, among other things, our ability to:

- Grant liens;
- Make certain loans or investments;

Incur additional indebtedness or guarantee other indebtedness;

Sell our assets; or

Acquire another company.

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Our credit agreement also contains financial covenants requiring us to maintain:

- Minimum consolidated net working capital of $35.0 million;
- A minimum EBITDA to consolidated fixed charge coverage ratio of 1.2 to 1.0;
- A maximum consolidated senior secured leverage to EBIDTA ratio of 3.5 to 1.0 with respect to the aggregate amount of borrowings outstanding under the acquisition facility plus other funded secured indebtedness; and
- A maximum consolidated total leverage to EBITDA ratio of 4.5 to 1.0 with respect to the aggregate amount of borrowings outstanding under the acquisition facility plus bonds and debentures and other funded indebtedness.

If any event of default exists under our credit agreement, the lenders will be able to accelerate the maturity of the credit agreement and exercise other rights and remedies. Each of the following would be an event of default:

- Failure to pay, when due, any principal, interest, fees or other amounts after a specific cure period;
- Failure of any representation or warranty to be true and correct in any material respect;
- Failure to perform or otherwise comply with the covenants in the credit agreement or in other loan documents to which we are a borrower without a waiver or amendment;
- Any default in the performance of any obligation or condition beyond the applicable grace period relating to any other indebtedness of more than $10.0 million;
- A judgment default for monetary judgments exceeding $10.0 million;
- A change of control as defined below;
- A bankruptcy or insolvency event involving us or any of our subsidiaries; and
- Failure of the lenders for any reason to have a first perfected security interest in the security pledged by us or any of the security becomes unenforceable or invalid.

A change of control is the occurrence of any of the following events: (a) Antonia A. Johnson, together with her spouse, children, grandchildren and heirs (and any trust of which any of the foregoing (or any combination thereof) constitute at least 80% of the then current beneficiaries) cease to own and control more than 50% of the total voting power of each class of outstanding equity interests of our general partner, (b) our general partner ceases to own and control all of the general partner interests in us, and (c) we cease to own and control all of each class of outstanding equity interests of each subsidiary that is a borrower or a guarantor under our credit agreement.

Impact of Inflation

Inflation in the United States and Canada has been relatively low in recent years and did not have a material impact on our results of operations for the years ended December 31, 2013, 2012 and 2011.

Critical Accounting Policies and Estimates

Use of Estimates

The Partnership s consolidated financial statements have been prepared in accordance with GAAP. The preparation of these consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results may differ from these estimates under different assumptions or conditions.

These estimates are based on our knowledge and understanding of current conditions and actions that we may take in the future. Changes in these estimates will occur as a result of the passage of time and the occurrence of future events. Subsequent changes in these estimates may have a significant impact on our financial condition and results of operations and are recorded in the period in which they become known. We have identified the following estimates that, in our opinion, are subjective in nature, require the exercise of judgment and involve complex analysis:

Derivatives

As a matter of policy, refined products and natural gas businesses utilize futures contracts, forward contracts, swaps, options and other derivatives in an effort to minimize the impact of commodity price fluctuations. On a selective basis and within our risk management policy s guidelines, we utilize futures contracts, forward contracts, swaps, options and other derivatives to generate profits from changes in market prices.

We record all derivative instruments as either assets or liabilities in the statement of financial position and measure those instruments at fair value. We recognize changes in the fair value of our commodity derivative instruments currently in earnings as cost of products sold.

We do not offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against fair value amounts, including amounts that approximate fair value, recognized for derivative instruments executed with the same counterparty under the same master netting arrangement.

We also use interest rate swaps to convert a portion of our floating rate debt to fixed rates. These interest rate swaps are designated as cash flow hedges and the changes in fair value of the swaps are included as a component of comprehensive income and accumulated other comprehensive loss, net of tax, in our consolidated statements of stockholder s/partner s equity and in our consolidated balance sheets, respectively.

Our derivative instruments are recorded at fair value, with changes in fair value recognized in net income or other comprehensive income each period as appropriate. Fair value measurements are determined using the market approach and include non-performance risk and time value of money considerations. Counterparty credit is considered for receivable balances, and our credit is considered for payable balances.

We determine fair value in accordance with Accounting Standards Codification (ASC) 820, Fair Value Measurement which established a hierarchy for the inputs used to measure the fair value of financial assets and liabilities based on the source of the input, which generally range from quoted prices for identical instruments in a principal trading market (Level 1) to estimates determined using significant unobservable inputs (Level 3). Multiple inputs may be used to measure fair value, however, the level of fair value is based on the lowest significant input level within this fair value hierarchy.

Details on the methods and assumptions used to determine the fair values are as follows:

Fair value measurements based on Level 1 inputs: Measurements that are most observable and are based on quoted prices of identical instruments obtained from the principal markets in which they are traded. Closing prices are both readily available and representative of fair value. Market transactions occur with sufficient frequency and volume to assure liquidity.

Fair value measurements based on Level 2 inputs: Measurements derived indirectly from observable inputs or from quoted prices from markets that are less liquid are considered Level 2. Measurements based on Level 2 inputs include over-the-counter derivative instruments that are priced on an exchange traded curve, but have contractual terms that are not identical to exchange traded contracts. We utilize fair value measurements based on Level 2 inputs for our fixed forward contracts, over-the-counter commodity price swaps, interest rate swaps and forward currency contracts.

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Fair value measurements based on Level 3 inputs: Measurements that are least observable are estimated from significant unobservable inputs determined from sources with little or no market activity for comparable contracts or for positions with longer durations.

Inventories

We value inventories at the lower of cost or market. Cost is primarily determined using the first-in, first-out method. Inventory consists of petroleum products, natural gas and coal. We use derivative instruments, primarily futures and swaps, to economically hedge substantially all of our inventory.

Goodwill

Goodwill is defined as the excess of cost over the fair value of assets acquired and liabilities assumed in a business combination. We review the carrying value of goodwill annually as of October 31st or on an as needed basis, for indicators of impairment at each reporting unit that has recorded goodwill. Impairment is indicated whenever the carrying value of a reporting unit exceeds the estimated fair value of a reporting unit.

For purposes of evaluating impairment of goodwill, we estimate the fair value of a reporting unit based upon future net discounted cash flows (Level 3 measurement). In calculating these estimates, historical operating results and anticipated future economic factors, such as estimated volumes and demand for services, commodity prices, and operating costs are considered as a component of the calculation of future discounted cash flows. Further, the discount rate requires estimates of the cost of equity and debt financing. The estimates of fair value of these reporting units could change if actual volumes, prices, costs or discount rates vary from these estimates. These assumptions contemplated business, market and overall economic conditions. We performed sensitivity analyses on the fair values resulting from the discounted cash flows valuation utilizing more conservative assumptions that reflect reasonably likely future changes in the discount rates and perpetual growth rate in each of the reporting units. Based upon our 2013 annual impairment testing analyses, including the consideration of reasonably likely adverse changes in assumptions described above, we believe it is not reasonably likely that an impairment will occur in any of the reporting units over the next twelve months.

Net Sales and Cost of Products Sold Recognition

Revenue is recognized through refined products, natural gas and materials handling revenue-producing activities, net of non-material provisions for discounts and allowances. At the time of sale for all revenue producing activities, persuasive evidence of an arrangement exists, delivery or service has occurred, the price is determinable and collectability is reasonably assured. Refined products revenue-producing activities include direct sales to customers including throughput and exchange locations. Revenue is recognized when the product is delivered. Revenue is not recognized on exchange agreements, which are entered into primarily to acquire refined products by taking delivery of products closer to the end markets. Any net differentials or fees for exchange agreements are recorded as cost of goods sold. Natural gas revenue-producing activities are direct sales to customers at various points on natural gas pipelines or at local distribution companies (*i.e.*, utilities). Revenue is recognized when the product is delivered. Materials handling service revenue is recognized monthly over the contractual service period or when the service is rendered.

The allowance for doubtful accounts is recorded to reflect the ultimate realization of our accounts receivable and includes the assessment of customers creditworthiness and the probability of collection. The allowance is comprised of specifically identified accounts at risk and an amount determined based on historical collection experience.

Shipping costs that occur at the time of sale are included in cost of product sold. Various excise taxes are collected at the time of sale and remitted to authorities and are recorded on a net basis in cost of products sold.

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Recent Accounting Pronouncements

In February 2013, the FASB issued ASU No. 2013-02, *Reporting Amounts Reclassified Out of Accumulated Other Comprehensive Income,* which amends ASC 220, *Comprehensive Income*. The amended guidance requires entities to provide information about the amounts reclassified out of accumulated other comprehensive income by component. Additionally, entities are required to present, either on the face of the financial statements or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income. The amended guidance does not change the current requirements for reporting net income or other comprehensive income. We adopted ASU 2013-02 as of January 1, 2013 and it did not have a material impact on our consolidated financial statements. Prior periods have been reclassified to conform to the current period presentation reflecting the impact of the adoption of ASU 2013-02.

In December 2011, the FASB issued ASU 2011-11, *Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities.* ASU 2011-11 requires an entity to disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. Entities are required to disclose both gross and net information about these instruments. ASU 2011-11 is effective for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods. We adopted ASU 2011-11 as of January 1, 2013 and it did not have a material impact on our consolidated financial statements, but did result in additional disclosure regarding fair value measurement.

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Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Market risk is the risk of loss arising from adverse changes in market rates and prices. The principal market risks to which we are exposed are commodity price risk, interest rate risk and market/credit risk. We utilize various derivative instruments to manage exposure to commodity risk and forward starting swaps to manage exposure to interest rate risk.

Commodity Price Risk

We use various financial instruments to hedge our commodity price risk. We sell our refined products and natural gas primarily in the Northeast. This geographic focus is a key factor in how we choose the most appropriate financial instruments to hedge our positions.

We hedge our refined products positions primarily with a combination of futures contracts that trade on the New York Mercantile Exchange, or NYMEX, and fixed-for-floating price swaps that are bilateral contracts that are traded over-the-counter. Although there are some notable differences between futures and the fixed-for-floating price swaps, both can provide a fixed price while the counterparty receives a price that fluctuates as market prices change. As indicated in the table below, we primarily use futures contracts to hedge light oil transactions and swaps contracts for residual fuel oils futures contracts. There are no residual fuel oil futures contracts that actively trade in the United States. Each of the financial instruments trade by month for many months forward, allowing us the ability to hedge future contractual commitments.

Product Group	Primary Financial Hedging Instrument
Gasolines	NYMEX RBOB futures contract
Distillates	NYMEX Ultra Low Sulfur Diesel futures contract
Residual Fuel Oils	New York Harbor 1% Sulfur Residual Fuel Oil Swaps

In addition to the financial instruments listed above, we sometimes use the ethanol futures contract that trades on the Chicago Board of Trade, or CBOT, to hedge ethanol that is used for blending into our gasoline. This ethanol contract is based on Chicago delivery.

For natural gas, there are no quality differences that need to be considered when hedging. Our primary hedging requirements relate to fixed price and basis (location) exposure. We largely hedge our natural gas fixed price exposure using fixed-for-floating price swaps that trade on the ICE with the prices based on the Henry Hub location near Erath, Louisiana. The Henry Hub is the most active natural gas trading location in the United States. Although we typically use swaps, there is also an actively traded NYMEX Henry Hub natural gas futures contract that we can use. We primarily use ICE basis swaps as the key financial instrument type to hedge our natural gas basis risk. Similar to the natural gas futures and ICE Henry Hub swaps, basis swaps for major locations trade actively for many months. These swaps are financially settled, typically using prices quoted by Platts.

We also directly hedge our price exposure in oil and natural gas physically by using forward purchases or sales.

The following table presents total realized and unrealized (losses) and gains on derivative instruments utilized for commodity risk management purposes. Such amounts are included in cost of products sold for the years ended December 31, 2013, 2012 and 2011:

	Years Ended December 31,		
		Predecessor	Predecessor
	2013	2012	2011
Refined products contracts	$ 504	$ (7,238)	$ (34,471)
Natural gas contracts	(76,707)	(19,580)	(377)
Total	$ (76,203)	$ (26,818)	$ (34,848)

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Substantially all of our commodity derivative contracts outstanding as of December 31, 2013 will settle prior to June 30, 2015.

Interest Rate Risk

We enter into interest rate swaps to manage exposures in changing interest rates. We swap the variable LIBOR interest rate payable under our credit agreement for fixed LIBOR interest rates. These interest rate swaps meet the criteria to receive cash flow hedge accounting treatment. Counterparties to our interest rate swaps are large multi-national banks and we do not believe there is a material risk of counterparty nonperformance. At December 31, 2013, the notional value of our cash flow hedges was composed of base notional amounts of $210.0 million expiring through 2015. Additionally, we may enter into seasonal swaps which are intended to manage our increase in borrowings during the winter, as a result of higher inventory and accounts receivable levels. Borrowings under our credit agreement bear interest, at our option, at a rate per annum equal to the Eurodollar Rate (which means the LIBOR Rate as determined from indices from the British Bankers Association) and the Alternate Base Rate which means the highest of (a) the prime rate of interest announced from time to time by the agent as its Base Rate, (b) 0.50% per annum above the Federal Funds Rate as in effect from time to time and (c) the Eurodollar Rate for 1-month LIBOR as in effect from time-to-time plus 1.00% per annum, depending on which facility is being used. During the two year period ended December 31, 2013, we hedged approximately 48% of our floating rate debt with fixed-for-floating interest rate swaps. We report unrealized gains and losses on the interest rate swaps as a component of accumulated other comprehensive gain or loss, net of taxes, which is reclassified to earnings as interest expense when payments are made. We expect to continue to utilize interest rate swaps to manage our exposure to LIBOR interest rates.

Derivative Instruments

The following tables present all of our financial assets and financial liabilities measured at fair value on a recurring basis as of December 31, 2013:

	As of December 31, 2013			
	Fair Value Measurement	**Quoted Prices in Active Markets Level 1**	**Significant Other Observable Inputs Level 2**	**Significant Unobservable Inputs Level 3**
Financial assets:				
Commodity exchange contracts	$ 165	$ 165	$	$
Commodity fixed forwards	64,729		64,729	
Commodity swaps and options	204		204	
Commodity derivatives	65,098	165	64,933	
Interest rate swaps				
Total	$ 65,098	$ 165	$ 64,933	$
Financial liabilities:				
Commodity fixed forwards	$ 128,368	$	$ 128,368	$
Commodity swaps and options	198		198	

Commodity derivatives	128,566			128,566	
Interest rate swaps	2,388			2,388	
Total	$ 130,954	$	$	130,954	$

Market and Credit Risk

The risk management activities for our refined products and natural gas segments involve managing exposures to the impact of market fluctuations in the price and transportation costs for commodities through the use of derivative instruments. The volatility of prices for energy commodities can be significantly influenced by market liquidity and changes in seasonal demand, weather conditions, transportation availability, and federal and state regulations. We monitor and manage our exposure to market risk on a daily basis in accordance with approved policies.

We maintain a control environment under the direction of our Chief Risk Officer through our risk management policy, processes and procedures, which our senior management has approved. Controls include volumetric, value at risk and stop loss limits on discretionary positions as well as contract term limits. Our Chief Risk Officer must approve the use of new instruments or new commodities. Risk limits are monitored and reported daily to senior management. Our risk management department also performs independent verifications of sources of fair values. These controls apply to all of our commodity risk management activities.

We use value at risk to monitor and control commodity price risk within our risk management activities. The value at risk model uses both linear and simulation methodologies based on historical information, with the results representing the potential loss in fair value over one day at a 95% confidence level. Results may vary from time to time as hedging coverage, market pricing levels and volatility change.

We have a number of financial instruments that are potentially at risk including cash and cash equivalents, receivables and derivative contracts. Our primary exposure is credit risk related to our receivables and counterparty performance risk related to the fair value of derivative assets, which is the loss that may result from a customer s or counterparty s non-performance. We use credit policies to control credit risk, including utilizing an established credit approval process, monitoring customer and counterparty limits, employing credit mitigation measures such as analyzing customer financial statements, and accepting personal guarantees and various forms of collateral. We believe that our counterparties will be able to satisfy their contractual obligations. Credit risk is limited by the large number of customers and counterparties comprising our business and their dispersion across different industries.

Cash is held in demand deposit and other short-term investment accounts placed with federally insured financial institutions. Such deposit accounts at times may exceed federally insured limits. We have not experienced any losses on such accounts.

The following table presents the value at risk for our refined products and natural gas marketing and risk management commodity derivatives activities:

	Refined Products		**Natural Gas**	
		Predecessor		**Predecessor**
	2013	**2012**	**2013**	**2012**
	(in thousands)		**(in thousands)**	
At December 31	$ 369	$ 105	$ 389	$ 326
Average	168	229	293	192
High	369	498	687	573
Low	72	54	130	49

Item 8. Financial Statements and Supplementary Data

See Part IV, Item 15 Index to Consolidated Financial Statements .

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

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

Our management, with the participation of our Chief Executive Officer and our Chief Financial Officer, evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2013. The term disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended, or the Exchange Act, means controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the SEC s rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is accumulated and communicated to the company s management, including its principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. Based on the evaluation of our disclosure controls and procedures as of December 31, 2013, our Chief Executive Officer and Chief Financial Officer concluded that, as of such date, our disclosure controls and procedures were effective at the reasonable assurance level.

Internal Control Over Financial Reporting

There have been no changes in our system of internal control over financial reporting during the quarter ended December 31, 2013 that have materially affected, or are reasonably likely to materially affect, the Partnership s internal control over financial reporting

Management s Report Regarding Internal Control

This Annual Report does not include a report of management s assessment regarding our internal controls over financial reporting or an attestation report of our independent registered public accounting firm due to a transition period established by the rules of the SEC for new public companies.

Item 9B. Other Information

None.

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Part III

Item 10. Directors, Executive Officers and Corporate Governance

Executive Officers and Directors of our General Partner

Our general partner oversees our operations and activities on our behalf through its board of directors. The board of directors of our general partner appoints our officers, all of whom are employed by the General Partner and manage our day-to-day affairs. Neither our general partner, nor the board of directors of our general partner, is elected by our unitholders and neither will be subject to re-election in the future. Rather, the directors of our general partner are appointed by Sprague Holdings, which owns 100% of our general partner. Following our initial public offering in October 2013, our board of directors met one time during 2013 fiscal year and each of its directors, following their appointment, attended the meeting and also attended any committee meetings on which they served.

NYSE rules do not require that the board of directors of our general partner be composed of a majority of independent directors. Nonetheless, the board of directors of our general partner has affirmatively determined that Messrs. Evans and Harper, who were appointed to the board of directors of our general partner in connection with our IPO meet the independence standards established by the NYSE. Sprague Holdings will appoint one additional independent director within twelve months of the date of the closing of our IPO.

The following table provides information as of March 20, 2014 for the executive officers and directors of our general partner. References to our officers, our directors, or our board refer to the officers, directors, and board of directors of our general partner. Directors are appointed to hold office until their successors have been elected or qualified or until the earlier of their death, resignation, removal or disqualification. Executive officers serve at the discretion of the board.

Name	Age	Position with our General Partner
Michael D. Milligan	50	Chairman of the Board of Directors
Ben J. Hennelly	43	Director
David C. Glendon*	48	President, Chief Executive Officer and Director
Gary A. Rinaldi*	56	Senior Vice President, Chief Operating Officer, Chief Financial Officer and Director
Robert B. Evans	65	Director
C. Gregory Harper	49	Director
Thomas F. Flaherty*	58	Vice President, Refined Products
Steven D. Scammon*	52	Vice President, Chief Risk Officer
Joseph S. Smith*	57	Vice President, Business Development
Paul A. Scoff*	54	Vice President, General Counsel, Chief Compliance Officer and Secretary
John W. Moore*	55	Vice President, Chief Accounting Officer and Controller
James Therriault*	53	Vice President, Materials Handling
Burton S. Russell	58	Vice President, Terminals
Brian W. Weego*	47	Vice President, Natural Gas
Frank B. Easton	67	Vice President, Human Resources
Kevin G. Henry	53	Vice President, Treasurer

* Indicates an executive officer for purposes of Item 401(b) of Regulation S-K.

Michael D. Milligan Mr. Milligan was appointed chairman of the board of directors of our general partner in July 2011. Mr. Milligan formerly served as a member of the board of directors of our predecessor and is the President & Chief Executive Officer of Axel Johnson, a position he has held since 2003. Prior to joining Axel Johnson, Mr. Milligan spent 17 years as a partner and member of the board of directors of Monitor Group, a global consulting and merchant banking group. While at Monitor, Mr. Milligan s activities covered a broad range of disciplines and industry sectors, including oil and gas, communications technology, specialty chemicals and retail and consumer products. Mr. Milligan holds a Bachelor of Arts degree from Bowdoin College and a Masters in Business Administration from Harvard University. We believe that Mr. Milligan s more than 20 years of experience in the energy industry, as well as his extensive management skills he acquired through his involvement in the strategy, operations and governance of Axel Johnson, brings substantial perspective and leadership to our board.

Ben J. Hennelly Mr. Hennelly was appointed to the board of directors of our general partner in July 2011. Mr. Hennelly currently serves as the Executive Vice President of Axel Johnson, a position he has held since March 13, 2007. Mr. Hennelly also currently serves as CFO of Decisyon Inc., an AJI portfolio company, which develops and markets enterprise collaboration software in the U.S. and Europe. Mr. Hennelly previously served as Chief Financial Officer for Axel Johnson during the period of March 2007 through June 2012. Mr. Hennelly has held various positions within the Axel Johnson Group since joining our predecessor in April 2003, including Vice President, Business Development of our predecessor and, more recently, Vice President, Corporate Development at Axel Johnson. Before joining the Axel Johnson Group, Mr. Hennelly was on the founding management team of EPIK Communications, a provider of broadband telecom services, and previously was a consultant with the Monitor Group, a global management strategy consulting firm, where he advised clients across a range of industries, including the energy industry. Mr. Hennelly holds a Bachelor of Arts degree from Cornell University and a PhD from Brown University. We believe that Mr. Hennelly s 15 years of consulting and management experience in a variety of industries, together with his deep understanding of our business from nearly three years of service at our predecessor, prepare Mr. Hennelly well to serve on the board of directors of our general partner.

David C. Glendon Mr. Glendon was appointed to the board of directors of our general partner and was named President and Chief Executive Officer of our general partner in July 2011, a position he held with our predecessor since January 15, 2008. Mr. Glendon was hired by our predecessor on June 30, 2003 as the Senior Vice President of Oil and Materials Handling, focusing on driving the execution of a customer-centric approach across all elements of the business. Prior to joining our predecessor, Mr. Glendon was a partner and global account manager at Monitor Group. He was also a founder and managing director of Monitor Equity Advisors, which worked with leading private capital providers in evaluating transactions and enhancing the strategic positions of their portfolio investments. Mr. Glendon received a Bachelor s degree, cum laude, in Psychology from Williams College and a Master s degree in Business Administration from the Stanford Graduate School of Business. As a result of his professional background, we believe Mr. Glendon brings executive-level strategic and financial skills along with significant operational experience that, when combined with his 15 years of consulting experience in a variety of industries and a deep knowledge of our business, make Mr. Glendon well-suited to serve on the board of directors of our general partner.

Gary A. Rinaldi Mr. Rinaldi was appointed to the board of directors of our general partner, and was named Senior Vice President, Chief Operating Officer and Chief Financial Officer of our general partner, in July 2011, a position he held with our predecessor since January 15, 2008. In such role, Mr. Rinaldi has responsibility for all terminals, materials handling and trucking operations, in addition to his duties as Chief Financial Officer. Mr. Rinaldi has been continuously employed by our predecessor since he was hired on April 27, 2003 as Senior Vice President and Chief Financial Officer. Prior to joining our predecessor, Mr. Rinaldi was Managing Director and Chief Financial Officer for the SUN Group. Prior to that, Mr. Rinaldi held several senior financial and operational management positions at Phibro Energy, a division of Salomon Inc., including Vice President and Chief Financial Officer and Director of Phibro Energy Production Inc. Mr. Rinaldi received his Bachelor s degree in Economics with a concentration in Accounting from The Wharton School, The University of Pennsylvania and is a former Certified Public Accountant. We believe that Mr. Rinaldi s experience with our predecessor plus his 22 years of prior experience in a variety of senior financial and operational management roles in the energy industry, when combined with his past service on multiple boards of directors, allows him to bring substantial experience and leadership skills to the board of directors of our general partner.

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C. Gregory Harper Mr. Harper was appointed to the board of directors of our general partner in October 2013 in connection with our IPO. On January 30, 2014, Mr. Harper was appointed President, Gas Pipelines and Processing for Enbridge Inc., a North American leader in delivering energy. On February 28, 2014, Mr. Harper was also appointed as the principal executive officer of Midcoast Holdings, L.L.C. Before joining Enbridge, Mr. Harper served as Senior Vice President of Midstream of Southwestern Energy Company, from August 2013 to January 2014. Before joining Southwestern Energy, Mr. Harper served as Senior Vice President and Group President of CenterPoint Energy Pipelines and Field Services from December 2008 to June 2013. Before joining CenterPoint Energy in 2008, Mr. Harper served as President, Chief Executive Officer and as a Director of Spectra Energy Partners, LP from March 2007 to December 2008. From January 2007 to March 2007, Mr. Harper was Group Vice President of Spectra Energy Corp., and he was Group Vice President of Duke Energy from January 2004 to December 2006. Mr. Harper served as Senior Vice President of Energy Marketing and Management for Duke Energy North America from January 2003 until January 2004 and Vice President of Business Development for Duke Energy Gas Transmission and Vice President of East Tennessee Natural Gas, LLC from March 2002 until January 2003. Mr. Harper currently serves on the board of directors of the Interstate Natural Gas Association of America, Midcoast Holdings, L.L.C., Enbridge Energy Company, Inc. and Enbridge Energy Management, L.L.C. Mr. Harper received his Bachelor s degree in Mechanical Engineering from the University of Kentucky and his Master s degree in Business Administration from the University of Houston. We believe Mr. Harper s extensive industry background, particularly his financial reporting and oversight expertise, will bring important experience and skill to the board of directors of our general partner.

Robert B. Evans Mr. Evans was appointed to the board of directors of our general partner in October 2013 in connection with our IPO. Mr. Evans has also served as a director of the General Partner of Targa Resources Partners, LP since February 2007, as a director of New Jersey Resources Corporation since 2009, and as a director of ONE Gas, Inc. since 2014. Mr. Evans was the President and Chief Executive Officer of Duke Energy Americas, a business unit of Duke Energy Corp., from January 2004 to March 2006, after which he retired. Mr. Evans served as the transition executive for Energy Services, a business unit of Duke Energy, during 2003. Mr. Evans also served as President of Duke Energy Gas Transmission beginning in 1998 and was named President and Chief Executive Officer in 2002. Prior to his employment at Duke Energy, Mr. Evans served as Vice President of marketing and regulatory affairs for Texas Eastern Transmission and Algonquin Gas Transmission from 1996 to 1998. Mr. Evans received his Bachelor s degree in Accounting from the University of Houston. We believe Mr. Evans s extensive energy industry background, particularly his experience in senior leadership roles and board positions of other energy companies, will provide the board of directors of our general partner with valuable knowledge and skill.

Thomas F. Flaherty Mr. Flaherty was appointed Vice President, Refined Products of our general partner in February, 2014 with responsibility for all activities in the business unit including Marketing, Supply, and Pricing. Previously, Mr. Flaherty was appointed to the position of Vice President, Sales of our general partner in July 2011, a position he held with our predecessor since November 28, 2006. In that role, Mr. Flaherty was responsible for all refined products sales and marketing activities. Mr. Flaherty has served in various roles during his continuous tenure with our predecessor since he was hired as an Account Executive in Coal Sales in July 1983, including Vice President, Commercial Sales and subsequently Vice President, Industrial Marketing. Prior to joining our predecessor, Mr. Flaherty was employed by Eastern Associated Coal Corp, a Pittsburgh based coal production company. Mr. Flaherty received his Bachelor s degree in Management from the University of Massachusetts and a Master s degree in Business Administration from the Whittemore School of Business, University of New Hampshire.

Steven D. Scammon Mr. Scammon was appointed Vice President, Chief Risk Officer of our general partner in February, 2014 with duties including overseeing risk management and related control processes, including all middle office activities and insurance groups. Previously, Mr. Scammon was appointed to the position of Vice President, Trading and Pricing of our general partner in July 2011, a position he held with our predecessor since January 28, 2008. In that role, Mr. Scammon was responsible for refined products trading and pricing. Mr. Scammon also managed customer service until February 2013 at which time it was moved into marketing. Mr. Scammon joined our predecessor as Vice President, Clean Products on December 26, 2000 and has been continuously employed by our predecessor since then. Prior to joining our predecessor, Mr. Scammon served as Senior Vice President with the Consolidated Natural Gas Energy Services Co. Prior to that, Mr. Scammon served in several positions with Louis Dreyfus Corporation including as Global Position Manager and Manager National Accounts. Mr. Scammon received his Bachelor s degree in Economics from Denison University.

Joseph S. Smith Mr. Smith was appointed Vice President, Business Development of our general partner in February, 2014 where he will lead acquisition sourcing and integration efforts in addition to overseeing the company s Sarbanes-Oxley compliance process. Previously, Mr. Smith was appointed Vice President, Chief Risk Officer and Strategic Planning of our general partner in July 2011, a position he held with our predecessor since July 3, 2006. In such role, Mr. Smith is tasked with oversight responsibility for risk management and related control processes. As part of that role, he had management responsibility for strategic planning, financial planning and analysis, middle office, and insurance groups. Mr. Smith has been an employee of our predecessor since April 2001 when he joined as Vice President, Corporate Planning and Development and was subsequently promoted to Vice President, Pricing and Performance Management. Prior to joining our predecessor, Mr. Smith was a Principal with Arthur D. Little, Inc. s international energy consulting practice. He also worked in various positions for Mobil Oil Corporation, including in the areas of sales and supply and research and development. Mr. Smith received his Bachelor s degree in Chemical Engineering from the University of Maine. He received a Master s degree in Chemical Engineering from Pennsylvania State University and a Master s degree in Business Administration in Finance from Drexel University.

Paul A. Scoff Mr. Scoff was appointed Vice President, General Counsel, Chief Compliance Officer and Secretary of our general partner in July 2011, a position he held with our predecessor since June 1, 2011. Mr. Scoff has been continuously employed by our predecessor since December 1999, serving as Vice President, General Counsel and Secretary during such time. Prior to joining our predecessor, Mr. Scoff was the Vice President and General Counsel of Genesis Energy L.P., a publicly traded master limited partnership. Prior to Genesis, Mr. Scoff served as Senior Counsel with Basis Petroleum (formerly known as Phibro Energy U.S.A. Inc., a division of Salomon Inc.). He also served as Senior Counsel with The Coastal Corporation prior to joining Basis Petroleum. He received his Juris Doctorate from the University of Houston Law Center in 1984 and his Bachelor s degree, cum laude, in Political Science and English from Washington and Jefferson College in 1981.

John W. Moore Mr. Moore was appointed Vice President, Chief Accounting Officer and Controller of our general partner in July 2011 and is responsible for our financial reporting, a position he held with our predecessor. Mr. Moore has been continuously employed by our predecessor since joining in June 1998 as the Chief Accounting Officer and Controller. Prior to joining our predecessor, Mr. Moore worked as an auditor at Arthur Andersen LLP and in various senior accounting management capacities at Phibro and Valero Energy Corporation. Mr. Moore s accounting experience includes both his experience with our predecessor plus 15 years of prior experience in the energy industry. Mr. Moore received a Bachelor s degree, magna cum laude, in Accounting from Texas Tech University and is a Certified Public Accountant.

James A. Therriault Mr. Therriault was appointed Vice President, Materials Handling of our general partner in July 2011, a position he held with our predecessor since October 2003. As Vice President, Materials Handling, Mr. Therriault is responsible for the sales and business development efforts of our materials handling business unit. Mr. Therriault has held a variety of business and financial positions since joining our predecessor in 1984. Mr. Therriault graduated from The University of New Hampshire in 1983 with a Bachelor of Arts degree in Economics and from the University of Southern New Hampshire in 1987 with a Master s degree in Business Administration.

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Burton S. Russell Mr. Russell was appointed Vice President, Operations of our general partner in July 2011, a position he held with our predecessor since 2003. As Vice President, Operations, Mr. Russell is responsible for the safe, environmentally responsible and cost efficient operation of our terminals and fleet. He joined our predecessor in 1998 and has continuously served in various positions, including responsibilities for terminals, fleet, safety, regulatory compliance, engineering and materials handling. Prior to joining our predecessor, Mr. Russell spent 21 years as a commissioned officer in the U.S. Coast Guard, serving the majority of that time in their Marine Technical, Port Safety and Environmental Protection programs. His last duty assignment was as the Captain of the Port, Officer in Charge of Marine Inspection and Federal On Scene Coordinator at the Marine Safety Office located in Portland, Maine. Mr. Russell received a Bachelor of Science degree in Ocean Engineering from the U.S. Coast Guard Academy. He received two Master s degrees from the University of Michigan: one in Naval Architecture and Marine Engineering and a second in Mechanical Engineering. He is also a licensed Professional Engineer.

Brian W. Weego Mr. Weego was appointed Vice President, Natural Gas of our general partner in July 2011, a position he held with our predecessor since June 7, 2010. As Vice President, Natural Gas, Mr. Weego is responsible for all elements of the natural gas business unit. Mr. Weego has been continuously employed by our predecessor since he was hired on December 7, 1998, having served as Manager, Natural Gas Supply Operations; Director, Natural Gas Marketing; and Managing Director, Natural Gas Marketing. Prior to joining our predecessor, Mr. Weego spent 11 years in various segments in the natural gas industry and has worked for the Coastal Corporation (wholesale natural gas origination and sales), O&R Energy (natural gas supply and trading) and Commonwealth Gas Company (natural gas utility supply planning and acquisition). Mr. Weego received a Bachelor of Science degree in Management from Lesley University and a Master s degree in Business Administration from the University of New Hampshire Whittemore School of Business and Economics.

Frank B. Easton Mr. Easton was appointed Vice President, Human Resources of our general partner in July 2011, a position he held with our predecessor since August 3, 1998. He previously served in a consulting capacity for our predecessor beginning in March 1998. Prior to joining our predecessor, Mr. Easton served as a Director of Human Resources at Dell Computer Corporation and Sequent Computer Systems, and, prior thereto, he served in a variety of finance and human resources roles at Wang Laboratories. Mr. Easton received his Bachelor s Degree in Sociology from Keene State College and his Master s Degree in Business Administration from the Executive Program, Whittemore School of Business, University of New Hampshire.

Kevin G. Henry Mr. Henry was appointed Vice President, Treasurer of our general partner in March 2012. Previously he was appointed Treasurer of our general partner in July 2011, a position he held with our predecessor since October 1, 2003. His primary responsibilities include managing liquidity, banking relationships, cash management and interest rate hedging programs. Additionally, Mr. Henry has management responsibility for the credit department and contract administration. Prior to joining our predecessor, Mr. Henry was an Assistant Treasurer for nine years with Tosco Corporation, a publicly held integrated oil company with refining, marketing and retail service stations. Mr. Henry previously worked for Phibro in various financial capacities. Mr. Henry received a Bachelor s degree in Management from St. Francis College with further accreditations from the Graduate School of Credit and Financial Management at Dartmouth College and the American Graduate School of International Management at Thunderbird University.

Committees of the Board of Directors

The board of directors of our general partner has an Audit Committee and a Conflicts Committee. Each of the standing Committees of the board of directors has the composition and responsibilities described below. NYSE rules do not require us to have a compensation committee or a nominating/corporate governance committee. Messrs. Evans and Harper are members of the audit committee and Messrs. Evans and Harper are the initial members of our conflicts committee.

Audit Committee

We are required to have an audit committee of at least three members by October 25, 2014, and all its members are required to meet the independence and experience standards established by the NYSE and the

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Exchange Act. Mr. Evans and Mr. Harper are the current members of our audit committee, and Sprague Holdings will appoint one additional independent director by October 25, 2014. The board of directors of our general partner has determined that each director appointed to the audit committee is financially literate, and Mr. Harper, who serves as chairman of the audit committee, has accounting or related financial management expertise and constitutes an audit committee financial expert in accordance with SEC and NYSE rules and regulations. The audit committee of the board of directors of our general partner serves as our audit committee and will assist the board in its oversight of the integrity of our consolidated financial statements and our compliance with legal and regulatory requirements and partnership policies and controls. The audit committee operates under a written charter and has the sole authority to (1) retain and terminate our independent registered public accounting firm, (2) approve all auditing services and related fees and the terms thereof performed by our independent registered public accounting firm, and (3) pre-approve any non-audit services and tax services to be rendered by our independent registered public accounting firm. The audit committee is also responsible for confirming the independence and objectivity of our independent registered public accounting firm. Our independent registered public accounting firm has been given unrestricted access to the audit committee and our management, as necessary. The audit committee was constituted in connection with our IPO and met twice during the remainder of the 2013 fiscal year.

Conflicts Committee

The board of directors of our general partner has established a conflicts committee to review specific matters that the board believes may involve conflicts of interest. The conflicts committee will determine if the resolution of any such conflict of interest is fair and reasonable to us. The board of directors of our general partner may, but is not required to, seek the approval of such resolution from the conflicts committee. The conflicts committee will determine if the resolution of the conflict of interest is fair and reasonable to us. Such a committee would consist of a minimum of two members, none of whom can be officers or employees of our general partner or directors, officers or employees of its affiliates (other than as directors of our subsidiaries) and each of whom must meet the independence standards for service on an audit committee established by the NYSE and the SEC. Messrs. Harper and Evans will serve as the initial independent members of the conflicts committee. Any matters approved by the conflicts committee will be conclusively deemed to be fair and reasonable to us, approved by all of our unitholders, and not a breach by our general partner of any duties it may owe us or our unitholders.

If the board of directors of our general partner does not seek approval from the conflicts committee, and the board of directors of our general partner approves the resolution or course of action taken with respect to the conflict of interest, then it will be presumed that, in making its decision, the board of directors of our general partner acted in good faith, and in any proceeding brought by or on behalf of us or any unitholder, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Corporate Code of Business Conduct and Ethics

The board of directors of our general partner has approved a Corporate Code of Business Conduct and Ethics which is applicable to all directors, officers and employees of our general partner, including the principal executive officer and the principal financial officer. The Corporate Code of Business Conduct and Ethics is available on our website at http://www.spragueenergy.com/investor-relations (under the Corporate Governance tab) and in print without charge to any unit holder who sends a written request to our secretary at our principal executive offices. We intend to post any amendments of this code, or waivers of its provisions applicable to directors or executive officers of our general partner, including its principal executive officer and principal financial officer, at this location on our website].

Procedures for Review, Approval and Ratification of Related Person Transactions

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

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

Available Information

We make available, free of charge within the Investor Relations Corporate Governance section of our website at www.spragueenergy.com and in print to any unitholder who so requests, our Audit Committee charter, Corporate Code of Business Conduct and Ethics, Corporate Governance Guidelines, Financial Code of Ethics, Insider Trading Policy, Short-Swing Trading and Reporting Policy and our Whistleblower Policy. Requests for print copies may be directed to: Investor Relations, Sprague Resources LP, 185 International Drive, Portsmouth, New Hampshire 03801 or made by telephone by calling (800) 225-1560. The information contained on or connected to our internet website is not incorporated by reference into this Annual Report and should not be considered part of this or any other report that we file with or furnish to the SEC.

Section 16(a) Beneficial Ownership Reporting Compliance

Each director, executive officer (and, for a specified period, certain former directors and executive officers) of our general partner and each holder of more than 10 percent of a class of our equity securities is required to report to the SEC his or her pertinent position or relationship, as well as transactions in those securities, by specified dates. Based solely upon a review of reports on Forms 3 and 4 (including any amendments) furnished to us during our most recent fiscal year and reports on Form 5 (including any amendments) furnished to us with respect to our most recent fiscal year, and written representations from officers and directors of our general partner that no Form 5 was required, we believe that all filings applicable to our general partner s officers and directors, and our beneficial owners, required by Section 16(a) of the Exchange Act were filed on a timely basis during 2013.

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Item 11. Executive Compensation

Compensation Committee Report

Neither we nor our general partner has a compensation committee. The Board of Directors of our general partner, or the Board , reviewed and discussed with management the section of this report entitled Compensation Discussion and Analysis (CD&A) and based on that review and discussion, approved its inclusion herein.

THE BOARD OF DIRECTORS
Michael D. Milligan
Robert Evans
C. Gregory Harper
Ben J. Hennelly

Compensation Discussion and Analysis

Introduction

Our general partner has sole responsibility for conducting our business and for managing our operations and its Board and officers make decisions on our behalf. We do not have any employees. We reimburse our general partner for the expenses associated with the services its employees provide to us, including compensation expenses for executive officers and directors of our general partner.

Historically, including during the fiscal year ended December 31, 2013, the President and Chief Executive Officer of our Predecessor worked with the compensation committee of Axel Johnson, or the Predecessor Committee, to set the pay for the executives of our Predecessor. The individuals who served as executives of our Predecessor began serving as executives of our general partner, and by extension serving as our executive officers, upon our formation in June 2011. Beginning on the closing of our initial public offering in October of 2013, the Board of our general partner took over responsibility for establishing and evaluating the pay for the executive officers of our general partner.

The purpose of this Compensation Discussion and Analysis is to explain our philosophy for determining the compensation program for the Chief Executive Officer, the Chief Financial Officer and the three other most highly compensated executive officers of our general partner for 2013, referred in this report as the Named Executive Officers , and to discuss why and how the 2013 compensation package for these executives was implemented. We were not formed until June 2011, and the assets and operations of our Predecessor were not contributed to us until the closing of our initial public offering in October of 2013. However, because the vast majority of the assets and operations of our Predecessor were contributed to us in connection with our initial public offering and the executive officers of our Predecessor are the executive officers of our general partner, we believe that disclosure regarding our executive officers compensation for the full fiscal year 2013, which was set and paid by our Predecessor, is generally appropriate and relevant to our own compensation philosophy and, as such, is disclosed in the tables below and discussed in this Compensation Discussion and Analysis. The Named Executive Officers for the fiscal year ending December 31, 2013 are as follows:

David C. Glendon President and Chief Executive Officer

Gary A. Rinaldi Senior Vice President, Chief Operating Officer and Chief Financial Officer

Thomas F. Flaherty	Vice President, Refined Products
Steven D. Scammon	Vice President, Chief Risk Officer
John W. Moore	Vice President, Chief Accounting Officer and Controller

Following this discussion are tables that include compensation information for the Named Executive Officers.

Objectives of Our Executive Compensation Program

Historically, our executive compensation program has been based on the following principles:

- The compensation paid to our executives should be competitive with that paid to the executives of those companies with which we compete for executive talent so that we attract and retain a skilled and experienced management team.

- Incentive compensation should be a material portion of total compensation so that our executives are properly motivated to focus on achieving or exceeding our financial and business goals.

- Axel Johnson should receive a threshold return on investment before the payout of any incentive compensation, so as to align the interests of the executive team with those of Axel Johnson.

Mr. Glendon and the Predecessor Committee believed these objectives were best met by providing a mix of competitive base salaries in combination with short- and long-term cash compensation. This mix of compensation elements has provided us with a successful compensation program that has allowed us to attract and retain a quality team of executives while motivating them to provide a high level of performance. As described in more detail below in the section entitled Setting Executive Compensation, beginning on the closing of our initial public offering, the Board of our general partner (including Mr. Glendon) took over the responsibility to oversee our executive compensation program. We expect that they will utilize similar principles as they manage these programs and set executive pay, although they may make certain adjustments to the types of compensation provided and performance metrics used in order to more accurately reflect a compensation program appropriate for a publicly traded entity. Specifically, we believe that ensuring that our unitholders receive a threshold return on investment before payout of incentive compensation will continue to be an important aspect of our compensation philosophy.

Setting Executive Compensation

The Predecessor Committee had the authority to make all major decisions with regard to the compensation of our Named Executive Officers. Historically, the Predecessor Committee asked that Mr. Glendon make recommendations regarding the base salaries for each of the Named Executive Officers (with the exception of his own compensation, which was set by the Predecessor Committee). Additionally, Mr. Glendon made recommendations to the Predecessor Committee regarding the level of annual and long-term bonuses he believed was appropriate for each of the Named Executive Officers based on their performance and level of responsibility. The Predecessor Committee took these recommendations into consideration when making final determinations with regard to the levels of annual and long-term bonuses for each of the Named Executive Officers. Mr. Glendon now works with the Board of our general partner in a similar fashion as he did with the Predecessor Committee, recommending base salaries for the remaining Named Executive Officers and working in connection with the Board to determine bonuses as well as other incentive compensation elements.

Components of Compensation

For the fiscal year ending December 31, 2013, the compensation for our Named Executive Officers consisted of the following elements:

Base salary;

Discretionary annual cash bonus awards;

Discretionary cash awards under our long-term incentive program (the LTIP); and

Other benefits, including retirement, car, health and welfare and related benefits.

Base Salary. Each Named Executive Officer s base salary is a fixed component of compensation and does not vary depending on the level of performance achieved. Base salaries for all executives, including Named Executive Officers, were historically set at levels deemed appropriate to retain their services. When establishing the base salary levels the Predecessor Committee and Mr. Glendon considered the responsibilities associated with each Named Executive Officer s position, each executive s experience, skill and education, and each executive s potential to contribute to our overall success. For example, when Mr. Glendon assumed the role as President and Chief Executive Officer, the Predecessor Committee considered both his prior experience and performance as our Senior Vice President of Sales and, prior to that, at the Monitor Group, as well as the additional responsibility that he would be taking on in his new position. In establishing the base salaries for the rest of our Named Executive Officers, the Predecessor Committee and Mr. Glendon also considered the extent to which the particular individual had the skills to help us solve the challenges we faced at that time and the expertise to help us meet our future business goals. Finally, the Predecessor Committee and Mr. Glendon considered the other employment opportunities available to the executive and earning potential associated with those opportunities. We expect that these factors will continue to drive base salary decisions.

Base salaries for each Named Executive Officer were reviewed annually by the Predecessor Committee as well as at the time of any promotion or significant change in job responsibilities and, in connection with each review, individual and company performance over the course of that year were considered. When they determined it appropriate, the Predecessor Committee utilized broad-based third-party compensation surveys in order to obtain a general understanding of current compensation practices. The Predecessor Committee did not use the information contained in these surveys to benchmark compensation, but rather to ensure that our pay practices are generally in line with the market. The Predecessor Committee did not utilize third-party surveys in its review of compensation levels for Named Executive Officers during 2013.

In 2014, following a review of base salary levels for each Named Executive Officer other than himself, Mr. Glendon recommended and the Board approved slight increases in the base salaries of Messrs. Flaherty, Scammon and Moore. This decision was made in an attempt to balance our desire to retain the services of these officers in a competitive employment market and account for slight increases in the cost of living, while acknowledging our concern regarding the relatively weak overall economy.

The Board chose not to increase the base salaries for Messrs. Glendon and Rinaldi at this time, choosing instead to focus on variable compensation. The 2014 increases below will become effective on March 31, 2014 for Messrs. Flaherty, Scammon and Moore.

Name	March 2014 Base Salaries	April 2013 Base Salaries	March 2012 Base Salaries
David C. Glendon	$ 350,000	$ 350,000	$ 350,000
Gary A. Rinaldi	$ 350,000	$ 350,000	$ 350,000
Thomas F. Flaherty	$ 253,170	$ 248,206	$ 245,749
Steven D. Scammon	$ 270,651	$ 258,285	$ 255,728
John W. Moore	$ 246,636	$ 241,800	$ 239,406

We believe that the competitive base salaries we pay to our Named Executive Officers help us to satisfy the objectives of our executive compensation program by attracting and retaining experienced executive talent. Additionally, by providing our Named Executive Officers with competitive base salaries, we mitigate risk by providing those individuals with a portion of their income that is not subject to change based on our financial performance.

Incentive Compensation Pool. The incentive compensation pool has historically been used to fund both our annual and long-term bonus programs. The incentive compensation pool formula was created by the Predecessor Committee in December of the year prior to the year to which the formula is applied. The incentive compensation pool calculation was based solely on earnings before taxes from operations, excluding any extraordinary one-time gains or losses from acquisitions or divestitures.

In March 2013, the Predecessor Committee approved the formula to be used to calculate the incentive compensation pool for 2013. The minimum acceptable threshold return to owner s equity is 5%. The calculation employs our predecessor s December 31, 2012 equity balance plus any amounts owed to Axel Johnson less any cash distributions made to Axel Johnson through February 28, 2013. Twenty six percent of Operating Cash Flow above the minimum acceptable threshold rate of return will be allocated to funding the 2013 incentive compensation pool. For the purpose of this calculation, Operating Cash Flow shall be defined as Profit Before Income Taxes, plus Depreciation and Amortization, less Capital Expenditures (to be measured on a GAAP basis). The incentive compensation pool will then be split to fund annual cash bonuses (75% of the incentive pool) and LTIP bonuses (25% of the incentive pool).

We believe this program fulfilled our executive compensation objectives by ensuring that the annual bonus program and LTIP were funded in a manner such that the employees who participated in those programs shared in our financial success, while ensuring that Axel Johnson received a minimum rate of return on their investment prior to the funding of the pool, and the majority of all profit in excess of that minimum.

The incentive compensation pool program, including both the annual cash bonus and cash long-term incentive programs, remained in effect through end of 2013, however, modification of the program for 2014 (and beyond) is currently under consideration. As such, the information above with respect to formulas used to calculate the incentive pool is subject to change. Further, future payments made under our annual bonus or long term incentive programs may be made in the form of our common units, cash or a combination of the two. Going forward, Mr. Glendon and the Board of our general partner will seek to satisfy similar objectives by instituting a new incentive compensation program that comparably achieves the goals of our executive compensation program. To this end, the Board authorized the engagement of Meridian Compensation Partners LLC to assist in developing the 2014 incentive compensation program.

Annual Bonus. A significant portion of the total compensation for each of our Named Executive Officers has historically been paid in the form of an annual cash bonus. While base salaries offer an important retention tool by providing a guaranteed income stream to our employees, we seek to incentivize and motivate employees to strive for both individual and overall company success by providing a substantial portion of their compensation in the form of discretionary annual cash bonuses so that our employees may share in the profits of the enterprise. Further, we feel that our industry has historically relied heavily on performance-based cash bonuses to compensate executive officers, and we want our compensation program to be consistent with industry trends and practices.

Annual cash bonuses for our Named Executive Officers are structured around target bonus amounts for each executive. When setting these targets for executives, including the Named Executive Officers, Mr. Glendon and the Predecessor Committee took into consideration each Named Executive Officer s position within the company as well as their relative level of responsibility and their ability to directly impact our success. The targets for Messrs. Flaherty, Scammon and Moore are each set at 50% of their base salary, which is consistent with other employees serving at the Vice President level. The target for Messrs. Glendon and Rinaldi is set at 100% of their base salary in order to reflect the additional responsibilities associated with their respective positions.

We have no obligation to pay the Named Executive Officers any amount of annual cash bonus; the target bonus amounts are simply guideposts or goals. The actual amount of annual bonus paid out to each of the Named Executive Officers varies from year to year based on both individual and company performance. The primary objective for all executives, including the Named Executive Officers, is the improvement of our aggregate financial performance. As such, our financial performance is reflected in the calculation of the incentive compensation pool and is also reflected in our evaluation of the individual s performance for the year. For example, we would take into account the performance and revenue generation of a division the Named Executive Officer oversees or a project that he or she worked on extensively. Named Executive Officers also have personal development objectives, for example, developing direct reports and bench strength, lowering expenses, implementing new systems, identifying and developing new business opportunities and successful execution of programs. These personal objectives are also taken into account in determining the amount of the Named Executive Officer s annual bonus relative to their target bonus.

Besides the formula used to calculate the incentive compensation pool, the process of determining the amount of each Named Executive Officer s annual bonus each year is largely subjective, not formula-based, and has been entirely in the discretion of Mr. Glendon and the Predecessor Committee.

We continued to use the annual cash bonus plan established by our Predecessor through the end 2013. For 2013, the amount of the annual cash bonus program pool was $6,154,000. Annual bonuses have historically been awarded to our Named Executive Officers at the discretion of Mr. Glendon and the Predecessor Committee. When determining the amount of each Named Executive Officer s bonus for 2013, Mr. Glendon and the Board took into consideration each Named Executive Officer s performance during the year, their level of responsibility, and their contribution to our financial success. For example, all executives, including the Named Executive Officers, received more than their target bonus in 2013 due to overall strong company performance being better than expected. Specifically, the company exceeded both the prior year s Adjusted Gross Margin as well as the Adjusted EBITDA. The Board took into account each Named Executive Officer s role in the achievement of these results when setting annual cash bonuses for 2013. It is anticipated the pool will be distributed to our Named Executive Officers, following the acceptance of our audited financial statements by our Board in March 2014.

We believe that our annual bonus program furthered the objectives of our executive compensation program in 2013 by (i) providing compensation opportunities that were competitive with those provided by companies with which we compete for executive talent, thereby helping us to attract and retain talented executives and (ii) tying our Named Executive Officers compensation to our financial success and each executive s individual performance, which in turn aligned our officer s interests with those of our investors.

Long-term incentive program. Another significant element of our historic executive compensation program was the opportunity to earn a cash bonus under our LTIP. We continued to use the long-term incentive program established by our Predecessor through the end of 2013. At the end of each year, Mr. Glendon has historically evaluated the performance of each Named Executive Officer (other than himself) in order to recommend to the Predecessor Committee the final LTIP award amount that he believed was warranted for each executive for that year. When determining the amounts to be distributed to the Named Executive Officers under the cash long-term incentive program, Mr. Glendon and the Board took into consideration each Named Executive Officer s position within the company as well as their relative level of responsibility and their ability to directly impact our longer term development and success. The amounts payable to Messrs. Glendon and Rinaldi were typically substantially similar and were greater than amounts paid to any other participants in the program in order to reflect the additional responsibilities associated with their respective positions. The amounts payable to Messrs. Flaherty, Scammon and Moore were typically less than the amounts paid to Messrs. Glendon and Rinaldi, which is consistent with other employees serving at the Vice President level. Differences in the amounts of the payments distributed under the long-term incentive program between these Vice President level executives, including our Named Executive Officers, has been based on a review of the executive s performance, increase or decrease in level of responsibility, and level of direct contribution to our financial success, strategic development, and growth, in each case, over the preceding year. There was no specific formula used in this analysis of performance. For example, in 2013 the cash long-term incentive pool that was generated for distribution to all executives, including the Named Executive Officers, reflected our overall improved company performance. Specifically, the company exceeded both the prior year s Adjusted Gross Margin as well as Adjusted EBITDA. The Board took into account each Named Executive Officer s role in the achievement of these results. The LTIP award that was eventually approved by the Board is designed to be paid in cash to each of the participants in three equal installments. The first payment has historically been made following our predecessor Board of Directors acceptance of our audited financial statements (typically in March of the year following the year for which the LTIP award was made) and the remaining two payments have been scheduled to be made at the same time in each of the following two years. However, the second and third payments are contingent upon (i) our earning at least the minimum acceptable threshold return (as described in more detail in the section above entitled Incentive Compensation Pool) for each of those years, (ii) the participant continuing to be employed by us on each of the payment dates, and (iii) our discretionary determination each year that such payments should be made based on company-wide as well as individual performance.

In 2013, our performance generated an aggregate LTIP bonus pool equal to $1,978,500 to be paid out in three equal annual installments of $659,500 per year contingent upon the factors enumerated above. It is anticipated the initial payment will be made following the acceptance of our audited financial statements by our Board in March 2014.

In 2012, our performance generated an aggregate LTIP bonus pool equal to $927,000 to be paid out in three equal annual installments of $309,000 per year contingent upon the factors enumerated above. The initial payment was made in March 2013 following the acceptance of our audited financial statements by our Predecessor Committee. It is anticipated the second payment of $309,000 for 2012 performance will be paid after Board acceptance of our audited 2013 financial statements in March 2014.

In 2011, our performance generated an aggregate LTIP bonus pool equal to $2,043,000 to be paid out in three equal annual installments of $681,000 per year contingent upon the factors enumerated above. The initial payment was made in April 2012 following the acceptance of our audited financials by our predecessor Board. The second payment of $681,000 for 2011 performance was paid in March 2013 after acceptance of our 2012 audited financial statements. It is anticipated the third and final payment of $681,000 for 2011 performance will be paid after Board acceptance of our audited 2013 financial statements in March 2014.

2013 Long-Term Incentive Plan

In order to incentivize our management for 2013 and beyond to continue to grow our business, our general partner adopted a new long-term incentive plan in October of 2013, the Sprague Resources LP 2013 Long-Term Incentive Plan, or the New LTIP, for the benefit of employees, consultants, and directors of our general partner and its affiliates, who perform services for us. Each of the Named Executive Officers is eligible to participate in the New LTIP. Unlike our Predecessor s LTIP, which provides only cash awards, the New LTIP provides us with the flexibility to grant unit options, restricted units, phantom units, unit appreciation rights, cash awards, distribution equivalent rights, substitute awards, and other unit-based awards, or any combination of the foregoing. These awards are intended to align the interests of plan participants (including the Named Executive Officers) with those of our unitholders and to give plan participants the opportunity to share in our long-term performance. As of the end of fiscal year 2013, we had not made any grants to the Named Executive Officers under the New LTIP.

Units Reserved Under the Plan

The New LTIP initially limited the number of common units that may be delivered pursuant to vested awards to 800,000 common units. On January 1 of each calendar year occurring after the second anniversary of the effective date and prior to the expiration of the New LTIP, the total number of common units reserved and available for issuance under the New LTIP will increase by 200,000 common units. Units cancelled, settled in cash, forfeited or withheld to satisfy exercise prices or tax withholding obligations will be available for delivery pursuant to other awards. The common units delivered pursuant to such awards may be common units acquired in the open market or acquired from any affiliate or other person, or any combination of the foregoing, as determined in the discretion of the committee (as defined below). As of March 20, 2013, we have issued a total of 6,666 units under the plan, all of which were issued to independent directors effective upon the closing of our initial public offering, leaving 793,334 units for future grants.

Administration of the Plan

The New LTIP will be administered by the Board of our general partner or an alternative committee appointed by the Board of our general partner, which we refer to together as the committee. The committee may also delegate its duties as appropriate. The New LTIP will expire upon the earlier of (i) its termination by the Board of our general partner,

(ii) the date common units are no longer available under the New LTIP for grants or (iii) the tenth anniversary of the date the New LTIP is approved by our general partner.

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2014 New LTIP Awards

In March of 2014, the Board approved the issuance of equity awards, including unit awards and phantom unit awards, to employees, including our Named Executive Officers, and independent directors. Those awards will be described more fully in the Partnership s Form 10-K report for the fiscal year ending December 31, 2014.

Severance and Change in Control Benefits

The Named Executive Officers did not have agreements with us that contained severance provisions or change in control payment provisions during the 2013 fiscal year. However, we have a general practice of paying severance to certain of our employees in the event they are terminated by us without cause and they agree to sign a release. The severance historically provided to executives, such as the Named Executive Officers, serving at the Vice President level and above consists of the following: (i) 12 months of severance, (ii) six months of outplacement support, and (iii) health and dental insurance for 12 months at the same cost to the individual as they paid during their employment with us.

We believe that the severance practices we have followed with regard to certain employees in the past have created important retention tools for us, as post-termination payments have allowed employees to leave our employment with value in the event of certain terminations of employment that were beyond their control. As a general matter, post-termination payments allow management to focus their attention and energy on making objective business decisions that are in the interest of the company without allowing personal considerations to affect the decision-making process. Additionally, executive officers at other companies in our industry and the general market in which we compete for executive talent commonly provide post-termination payments, and we have consistently provided this benefit to certain executives in order to remain competitive in attracting and retaining skilled professionals in our industry. Certain executives, including the Named Executive Officers, will continue to receive potential severance benefits following our initial public offering in connection with qualifying terminations of employment and/or change in control events, but we have not put any specific plans or individual agreements in place at this time.

Other Benefits

Health and Welfare Benefits. All of our regular scheduled full-time employees, including our Named Executive Officers, receive the same health and welfare benefits. The benefits include group health, vision, and dental insurance coverage; participation in our 401(k) and defined contribution pension plan; short- and long-term disability insurance and life insurance coverage; participation in our flexible spending plan; and tuition assistance. The health and dental plans require employee contributions toward the cost of premiums. We provide short- and long-term disability as well as basic life insurance at no cost to our employees. Employees may also elect additional life insurance coverage at their own expense.

Retirement Benefits. We provide all of our employees who were hired prior to January 1, 1991, who were scheduled to work at least 30 hours per week, and who met certain age and service requirements with the opportunity to participate in our retiree health plan. The obligation for premiums under the retiree health plan is shared by both us and the participants and our contributions to such premiums are capped. The retiree health plan does not provide dental benefits. Because Mr. Flaherty is the only Named Executive Officer that was employed by our predecessor prior to January 1, 1991, he is the only Named Executive Officer who may be eligible to participate in our retiree health plan. We also provide our employees with the opportunity to receive post-retirement life insurance on a non-discriminatory basis so long as certain age and service requirements are met. We have historically provided all eligible employees with a retirement program that consisted of two separate plans. All retirement plans discussed below are sponsored and administered by Axel Johnson.

Defined Benefit and Defined Contribution Plans. The Axel Johnson Inc. Retirement Plan, or the DB Plan, is a defined benefit pension plan. The DB Plan was discontinued as of December 31, 2003 and benefits were frozen as of that date with immediate vesting for all active participants in the plan at their then-accrued benefit level. The Axel Johnson Inc. Retirement Restoration Plan, or the RRP, is a related unfunded supplemental plan that provides benefits to employees participating in the DB Plan to the extent benefits cannot be paid from the DB Plan due to legal limitations on the amounts paid under qualified plans set forth in the Internal Revenue Code. In general, the RRP provides benefits for DB Plan participants whose benefits would be limited or whose allowable DB Plan compensation would be limited. As with the DB Plan, benefits under the RRP were frozen as of December 31, 2003. In place of the DB Plan, we implemented a new defined contribution plan, or the DC Plan. The DC Plan was implemented on January 1, 2004. We make all contributions under the DC Plan and participants are not allowed to make contributions. A defined contribution plan specifies the amounts the company will contribute to the plan, but investment decisions and the market risk of those decisions are the obligation of the participant. We contribute an amount equal to 5% of all eligible compensation (including base pay, annual bonus, overtime and commissions) each month to the plan into accounts for every eligible employee, including the Named Executive Officers. Up to an additional 8% is contributed for employees with certain levels of service who participated in the DB Plan when it was frozen and were close to retirement age. This additional contribution was implemented by the Predecessor Committee and our management and is intended to help those employees with a shorter earnings horizon, as they had little time to adjust their financial retirement planning following our decision to freeze the DB Plan. Full-time employees or part-time who are regularly scheduled to work more than 1,000 hours annually are eligible to participate. Participating employees are immediately 100% vested in all contributions under the DC Plan.

401(k) Thrift Plan. The second effective retirement plan is a 401(k) thrift plan. All employees who are scheduled to work more than 1,000 hours per year, including the Named Executive Officers, are allowed to contribute their own funds to their 401(k) account and we have historically made certain matching contributions. Employees can contribute between 2% and 70% of their pay (base pay, annual bonus, overtime pay, and commissions) on a pre-tax basis and/or an after-tax basis; however, combined pre-tax and after-tax contributions cannot exceed 70% of pay. The amounts that can be contributed are also subject to the annual limitations imposed by federal tax law. The company will match 60% of the first 6% of pay that an employee contributes to a pre-tax or Roth Plan. Participating employees are immediately 100% vested in all contributions including employee and company contributions as well as any earnings of the plan.

Automobiles and Auto Allowances. We provide cars to employees based on their job requirements, such as the amount of travel that is necessary in order for the executive to properly perform his job duties. Those employees who are eligible to receive a car benefit may elect whether to receive the use of a company car or a cash auto allowance. In 2013, three Named Executive Officers were eligible to receive this benefit; Mr. Scammon (who elected to use a company car) and Messrs. Flaherty and Moore (who elected to receive the auto allowance).

Risk Assessment

The Board has reviewed our compensation policies as generally applicable to the employees of our general partner and believes that such policies do not encourage excessive and unnecessary risk-taking, and that the level of risk that they do encourage is not reasonably likely to have a material adverse effect on us. Each time a new compensation policy or program is implemented we consider any risks that may be created by its implementation and work to design the program so as to minimize such risks. In addition, we continually reevaluate the effectiveness of our compensation programs, including an evaluation of the incentives such programs create and how we can minimize or eliminate incentives that may create risk for us.

We believe the use of base salary and performance-based compensation plans that are generally uniform in design and operation throughout our organization and with all levels of employees are consistent with our compensation philosophy. These compensation policies and practices are centrally designed and administered, and are substantially identical between our business divisions, except in cases such as commission arrangements which have been tailored to encourage specific sales behavior. In addition, we believe the following specific factors, in particular, reduce the likelihood of excessive risk-taking:

Our overall compensation levels are competitive with the market.

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Our compensation mix is balanced among fixed components like salary and benefits, as well as annual incentives that reward overall financial performance, business unit financial performance, operational measures and individual performance.

An important portion of our executive compensation is tied to our owner s return on equity over a period of multiple years, with cash-based awards that are paid out over three years. The LTIP does not pay any awards to executives until the company meets a minimum threshold rate of return each year. Spreading payments over three years encourages executives to focus on our owner s return on equity over the longer term. The new long-term bonus program being designed will support similar behavior by executives and encourage them to focus on unitholder interests. The plan is also intended to foster retention.

The Board of our general partner has discretion to reduce performance-based awards when it determines that such adjustments would be appropriate based on our interests and the interests of our unitholders. In a similar manner, the company also has the ability to exercise discretion to reduce or alter performance-based compensation plans, e.g., commission plans, when it is determined that adjusting the plan is appropriate and in the interest of our unitholders.

Although a significant portion of the compensation provided to Named Executive Officers is performance-based, we believe our compensation programs do not encourage excessive and unnecessary risk taking by executive officers (or other employees) because these programs are designed to encourage employees to remain focused on both our short and long-term operational and financial goals. We set performance goals that we believe are reasonable in light of our past performance and market conditions. At the end of each year, we review the performance of every employee as part of an annual performance review that involves several levels of management oversight. The results of those performance reviews, in addition to our short- and long-term performance, become a major factor in determining what incentives each employee will receive.

A portion of the performance-based, variable compensation we provide is comprised of long-term incentives in the form of awards that are subject to non-payment if the organization does not achieve a minimum threshold rate of return. As such, executives are less likely to take unreasonable risks. Our performance-based incentives, assuming achievement of at least a minimum threshold rate of return, do provide payouts of some compensation at levels below full target achievement, in lieu of an all or nothing approach.

Additionally, we have a Chief Risk Officer who chairs a Risk Management Committee comprised of several members of management and a representative of our sponsor, that is responsible for reviewing all policies and procedures which could encourage risk taking. In addition to our internal reporting structure, the Chief Risk Officer has a direct reporting relationship to the Board and has the authority to review all aspects of our business to ensure that employees are not encouraged to take unnecessary or inappropriate risks.

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Summary Compensation Table for Years Ended December 31, 2013

The table below summarizes the total compensation earned by or paid to our Named Executive Officers in fiscal year 2013.

Name and Title	Year	Salary ($)(1)	Bonus ($)(2)	All Other Compensation ($)(3)	Total ($)
David C. Glendon	2013	350,000	802,000	22,259	1,174,259
President and Chief Executive Officer	2012	350,000	486,500	21,550	858,050
	2011	342,308	950,000	21,070	1,313,378
Gary A. Rinaldi	2013	350,000	802,000	22,309	1,174,309
Senior Vice President, Chief Operating Officer and	2012	350,000	486,500	21,600	858,100
Chief Financial Officer	2011	342,308	950,000	21,070	1,313,378
Thomas F. Flaherty	2013	247,545	270,000	47,063	564,608
Vice President, Refined Products	2012	244,250	162,000	45,843	452,093
	2011	238,180	300,000	45,070	583,250
Steven D. Scammon	2013	257,597	249,600	29,758	536,955
Vice President, Chief Risk Officer	2012	254,321	147,000	29,400	430,721
	2011	249,236	290,000	28,870	568,106
John W. Moore	2013	241,156	265,000	29,182	535,338
Vice President, Chief Accounting Officer and Controller					

(1) Amounts in this column reflect all compensation earned by the Named Executive Officers during the 2013 fiscal year as base salary. Prior to April 2013, the base salaries for Messrs. Glendon, Rinaldi, Flaherty, Scammon and Moore were $350,000, $350,000, $245,749, $255,728, and $239,406, respectively. After April 2013 the base salaries for Messrs. Glendon, Rinaldi, Flaherty, Scammon and Moore were as follows: $350,000, $350,000, $248,206, $258,285, and $241,800, respectively.

(2) Amounts in this column reflect the amount of (i) the annual bonus award for 2013, (ii) the third (and final) payment under the 2011 LTIP award, (iii) the second payment under the 2012 LTIP award, and (iv) the first payment under the 2013 LTIP award.

(3) Amounts in this column reflect (i) a 401(k) plan matching contribution to Messrs. Glendon, Rinaldi, Flaherty, Scammon and Moore in the amounts of $9,180, $9,180, $8,934, $9,180, and $8,778, respectively; (ii) our contribution to the DC Plan for Messrs. Glendon, Rinaldi, Flaherty, Scammon and Moore in the amounts of $12,750, $12,750, $25,500, $12,750, and $12,750, respectively; (iii) use of a company car for Mr. Scammon, the value of which is estimated to be $7,800 and (iv) Messrs. Flaherty s and Moore s car allowance in the amount of $12,000 and $7,200 respectively for the 2013 year. Messrs. Glendon, Rinaldi, Flaherty, and Moore also received wellness incentives in the amounts of $50, $100, $50 and $100 respectively. As a part of the service recognition program available to all employees, Messrs. Glendon, Rinaldi, Flaherty and Moore received services awards of $250, $250, $550 and $325 respectively.

Although we typically make a contribution to the DC Plan equal to 5% of each Named Executive Officer s base pay, we make a supplemental contribution of an additional 5% for Mr. Flaherty, and as such the amount of his DC Plan contribution is double that of the other Named Executive Officers.

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Pension Benefits

The following table summarizes the benefits that our Named Executive Officers have accrued under the DB Plan and the RRP in fiscal year 2013.

Name	Plan Name	Number of Years Credited Service (#)(1)(2)	Present Value of Accumulated Benefit ($)(3)	Payments During 2013 Fiscal Year ($)
David C. Glendon	Axel Johnson Inc. Retirement Plan			
President and Chief Executive Officer	Axel Johnson Inc. Retirement Restoration Plan			
Gary A. Rinaldi	Axel Johnson Inc. Retirement Plan			
Senior Vice President, Chief Operating Officer and Chief Financial Officer	Axel Johnson Inc. Retirement Restoration Plan			
Thomas F. Flaherty	Axel Johnson Inc. Retirement Plan	20.42	$ 585,944	
Vice President, Refined Products	Axel Johnson Inc. Retirement Restoration Plan	20.42	$ 154,528	
Steven D. Scammon	Axel Johnson Inc. Retirement Plan	3.00	$ 62,949	
Vice President, Chief Risk Officer	Axel Johnson Inc. Retirement Restoration Plan	3.00	$ 18,106	
John W. Moore	Axel Johnson Inc. Retirement Plan	5.50	$ 119,629	
		5.50	$ 5,158	
Vice President, Chief Accounting Officer and	Axel Johnson Inc. Retirement			

Controller	Restoration Plan

(1) Amounts in this column represent the number of years of credited service rounded to the nearest month and were frozen as of December 31, 2003.
(2) Messrs. Glendon and Rinaldi were not eligible to participate in the DB Plan or the RRP since they were hired after January 1, 2003.
(3) Amounts in this column represent the present value of each Named Executive Officer s accumulated benefit under the DB Plan and the RRP as of December 31, 2013. In quantifying the present value of the accumulated benefit indicated above, we used the same assumptions used for financial reporting purposes under GAAP, except that retirement age was assumed to be the earliest time at which a participant may retire under the plan without any benefit reduction due to age. The material assumptions were as follows: (i) an estimated discount rate of 4.90% for the Axel Johnson Inc. Retirement Plan and 4.80% for the Axel Johnson Inc. Retirement Restoration Plan, (ii) the mortality rates published in the IRS 2013 Static Mortality Table and (iii) expected long-term rate of return on plan assets of 7.25%.

The information in the table above relates to our Named Executive Officers participation in the DB Plan and the RRP. The DB Plan and RRP were available to employees of subsidiaries of Axel Johnson who were

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scheduled to work at least 20 hours per week (or 1,000 hours per year), were not temporary or leased employees, and who satisfied a one-year waiting period. The DB Plan and the RRP were both discontinued as of December 31, 2003 and benefits were frozen (*i.e.*, participants will experience no increase attributable to years of service or change in eligible earnings) as of that date with immediate vesting of all active participants in the plan at their then-accrued benefit level. We implemented the DC Plan on January 1, 2004 to replace the DB Plan.

The benefits paid under the RRP are determined by calculating the benefits payable from the DB Plan as if there were no legal limitations, and then subtracting the actual benefits payable from the DB Plan. The DB Plan benefit paid to participants is based on a formula using the employee s final average compensation, credited service, and social security covered compensation, each of which is calculated on the earlier of December 31, 2003 or the date of retirement or termination. The annual annuity benefit payable at retirement under the DB Plan is calculated as follows:

1.1% of final average compensation	x	Credited service (up to 40 years, rounded to the nearest month)	+	0.4% of final average compensation in excess of social security covered compensation	x	Credited service (up to 35 years, rounded to the nearest month)

A participant s final average compensation is calculated by taking the average of a participant s highest pensionable earnings in any 60-consecutive-month period before the earlier of December 31, 2003, termination, or retirement. Pensionable earnings include regular wages or salary, overtime, shift differentials, short-term incentive payment, and commissions. Employees generally received one year of credited service for each calendar year in which the employee performed 1,000 hours or more of service. Social security wage covered compensation is typically the average of the social security wage bases for the 35-year period ending with the last day of the calendar year in which a participant is eligible for unreduced social security retirement benefits. However, because each participant s benefit had to be calculated as of December 31, 2003 when the DB Plan was frozen, the calculation was based on the social security covered compensation in effect as of the earlier of 2003 or the year the participant terminated employment. If the calculation date was prior to social security retirement age, the social security covered compensation is calculated assuming the wage base for all future years is equal to the then-current year s wage base.

The normal retirement age is 65 years old. A participant may qualify for early retirement if, when the participant leaves the company, that participant is at least 55 years old and has at least ten years of total credited service. As of December 31, 2013, Messrs. Flaherty and Moore were the only Named Executive Officer eligible for early retirement; no Named Executive Officer was eligible for normal retirement. A participant can receive full DB Plan benefits as early as the participant s 62nd birthday. If a participant elects to receive a benefit prior to age 62, the benefit would be reduced by 5/12% for each month (5% per year) that the benefit starts before age 62. If a participant ceases to be employed by us prior to age 55 or prior to accumulating ten years of credited service, the participant may elect to receive the deferred vested benefit beginning as early as age 55. However, if the participant elects to receive the benefit before the normal retirement date, such benefit will be reduced by $^1/_2$% for each month (6% per year) that payment of the benefit starts before the normal retirement date.

Payment methods are determined based on the participant s marital status and/or election. The normal form of payment for a single participant is a life income annuity; for a married participant, it is a 50% joint and survivor annuity. Optional payment methods include a contingent annuitant option at 50%, 75% or 100%; a life income option; a 120 month certain and life income option; or a Social Security adjustment option. If a married participant dies, his or her spouse is entitled to survivor benefits. The time and form of payment under the RRP is typically identical to the time and form of payment under the DB Plan or may be in the form of an actuarially equivalent lump sum paid at the time benefits commence under the DB Plan.

Potential Payments Upon Termination or a Change in Control

The Named Executive Officers did not have agreements with us that contained severance provisions or change in control payment provisions during the 2013 fiscal year. However, we have a general practice of paying severance to certain of our employees in the event they are terminated by us without cause and they agree to sign a release. A termination without cause has historically been determined on a case by case basis rather than by applying any one definition or a specific set of events to each employee. The severance historically provided to executives, such as the Named Executive Officers, serving at the Vice President level and above consists of the following: (i) 12 months of severance, (ii) 6 months of outplacement support and (iii) health and dental insurance for 12 months at the same cost to the individual as they paid during their employment with us. The table below shows our best estimate as to the amounts that each of the Named Executive Officers would have received on December 31, 2013, if the Predecessor Board had determined that the individual s employment was terminated without cause on that date.

Name	Cash Severance	Outplacement Support (1)	Health and Dental (2)	Total Severance Benefits
David C. Glendon President and Chief Executive Officer	$ 350,000	$ 6,000	$ 14,001	$ 370,001
Gary A. Rinaldi Senior Vice President, Chief Operating Officer and Chief Financial Officer	$ 350,000	$ 6,000	$ 9,873	$ 365,873
Thomas F. Flaherty Vice President, Refined Products	$ 248,206	$ 6,000	$ 14,001	$ 268,207
Steven D. Scammon Vice President, Chief Risk Officer	$ 258,285	$ 6,000	$ 13,205	$ 277,490
John W. Moore Vice President, Chief Accountant and Controller	$ 241,800	$ 6,000	$ 14,001	$ 261,801

(1) Amounts in this column reflect the estimated cost to us of providing outplacement services to the Named Executive Officers over a six-month period; however, such services would be provided by an outside vendor and could vary based on the individual needs of each executive.

(2) Amounts in this column reflect the value of continued health and dental benefits based on the value of the benefits received by each individual as of December 31, 2013.

2013 DIRECTOR COMPENSATION

We use a combination of cash and equity compensation to attract and retain qualified candidates to serve as directors. In setting director compensation, we consider the time commitment directors must make in performing their duties, the level of skills required by directors and the market competitiveness of director compensation levels. Directors who are employees of our general partner, Axel Johnson or affiliates of either do not receive any additional compensation for serving as directors.

Independent directors receive an annual retainer of $60,000 paid in quarterly installments. In addition, each independent director who serves as chairman of a committee receives an annual retainer of $10,000, and each independent director who serves as a committee member receives an annual retainer of $5,000, in each case, paid in quarterly installments.

Further, each independent director will receive an annual grant on the anniversary of the director s appointment to the Board, of a number of restricted units having a fair market value of approximately $60,000 under the New LTIP. The restricted units vest in accordance with the terms of the applicable award agreement. Generally, upon termination of the director s services with the General Partner or an affiliate other than due to death or Disability, all outstanding, unvested restricted units will be automatically forfeited; however, if the director s services terminate due to death or Disability, then all outstanding, unvested restricted units immediately become vested and non-forfeitable. Disability is defined as being unable to engage in substantial gainful activity by reason of any medically determinable physical or mental impairment that can be expected to result in death or can be expected to last for a continuous period of not less than 12 months. In the event of a Change of Control (as defined in the New LTIP or the award agreement, as applicable), all outstanding, unvested restricted units will immediately vest and become non-forfeitable. In addition to the annual grant described above, in March 2014, the Board approved the issuance of a special one-time unit award to each independent director. Those awards will be described more fully in the company s Annual Report on Form 10-K for 2014.

Each director is reimbursed for out-of-pocket expenses incurred in connection with attending committee meetings. Each director receives liability insurance coverage and is fully indemnified by us for actions associated with being a director to the fullest extent permitted under Delaware law.

The table below summarizes the compensation paid to independent directors for the fiscal year ended December 31, 2013.

Name (1)	Fees Earned or Paid in Cash ($) (3)	Unit Awards ($) (4)	Total ($)
Michael D. Milligan (2)			
Robert B. Evans	$ 18,750	$ 57,861	$ 76,661
C. Gregory Harper	$ 18,750	$ 57,861	$ 76,661
Ben J. Hennelly (2)			

(1) Messrs. Glendon and Rinaldi serve as our Named Executive Officers and are not included in this table because they receive no compensation for their services as directors and the compensation received by Messrs. Glendon and Rinaldi as our Named Executive Officers is shown in the Summary Compensation Table.

(2) Messrs. Milligan and Hennelly, as officers of Axel Johnson, do not receive separate compensation for their services as directors.

(3) The amounts in this column reflect the aggregate dollar amount of fees earned or paid in cash including the prorated annual retainer fee and chairmanship or membership fees. Mr. Evans served on the Conflicts Committee (Chairman) and the Audit Committee, and Mr. Harper served on the Audit Committee (Chairman) and Conflicts Committee.

(4) The amounts included in this column represent the aggregate grant date fair value of restricted shares granted to each independent director during 2013, computed in accordance with Financial Accounting Standards Board Accounting Standards Codification Topic 718 (FASB ASC Topic 718). The value ultimately realized by each director may or may not be equal to this determined value. For a discussion of valuation assumptions, see Note 21 Equity-Based Compensation of the Notes to Consolidated Financial Statements included under Item 8 in this Annual Report on Form 10-K for the year ended December 31, 2013. Messrs. Evans and Harper each received an award of 3,333 restricted units under the LTIP effective November 1, 2013. The restricted units vest as to 1/3 of the total number granted on each of the first three anniversaries of the date of grant. As of December 31, 2013, Messrs. Evans and Harper each had 3,333 restricted units outstanding.

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Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The following table sets forth the beneficial ownership of common units and subordinated units of Sprague Resources LP that are issued and outstanding as of March 20, 2014 and held by:

each person known by us to be a beneficial owner of more than 5% of our outstanding units, including Sprague Holdings;

each of the directors of and nominees to our general partner s board of directors;

each of the named executive officers of our general partner; and

all of the directors, director nominees and executive officers of our general partner as a group.

The amounts and percentage of units beneficially owned are reported on the basis of regulations of the SEC governing the determination of beneficial ownership of securities. Under the rules of the SEC, a person is deemed to be a beneficial owner of a security if that person has or shares voting power, which includes the power to vote or to direct the voting of such security, or investment power, which includes the power to dispose of or to direct the disposition of such security. Except as indicated by footnote, the persons named in the table below have sole voting and investment power with respect to all units shown as beneficially owned by them, subject to community property laws where applicable.

Name of Beneficial Owner(1)	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned	Subordinated Units Beneficially Owned	Percentage of Subordinated Units Beneficially Owned	Percentage of Common and Subordinated Units Beneficially Owned
Sprague Holdings(2)(3)	1,571,970	15.6%	10,071,970	100.0%	57.8%
Axel Johnson(3)(4)	1,571,970	15.6	10,071,970	100.0	57.8
Lexa International Corporation(3)(5)	1,571,970	15.6	10,071,970	100.0	57.8
Antonia Ax:son Johnson(3)(6)	1,571,970	15.6	10,071,970	100.0	57.8
Kayne Anderson Capital Advisors, L.P. (7)	1,748,690	17.4%			8.7%
Goldman Sachs Asset Management, L.P. (8)	754,046	7.5%			3.7%
Harvest Fund Advisors LLC (9)	713,085	7.1%			3.5%
Oppenheimer Funds Inc. (10)	539,090	5.4%			2.7%
Michael D. Milligan	20,000	*			*
Gary A. Rinaldi	5,001	*			*
David C. Glendon	5,000	*			*

Robert B. Evans	3,333	*	*
C. Gregory Harper	3,333	*	*
Ben J. Hennelly			
Thomas E. Flaherty			
Steven D. Scammon			
John W. Moore			
All executive officers and directors of our general partner as a group (13 persons)	40,267	*	*

* Represents less than 1%.

(1) As of the date of this Annual Report, there are no arrangements for any listed beneficial owner to acquire, within 60 days, any common units from options, warrants, rights, conversion privileges or similar instruments.

(2) The address for this entity is 185 International Drive, Portsmouth, NH 03801.

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(3) Common units and subordinated units shown as beneficially owned by Axel Johnson, Lexa International Corporation and Antonia Ax:son Johnson reflect common units and subordinated units owned of record by Sprague Holdings. Sprague Holdings is a wholly-owned subsidiary of Axel Johnson and, as such, Axel Johnson may be deemed to share beneficial ownership of the units beneficially owned by Sprague Holdings, but disclaims such beneficial ownership. Axel Johnson is a wholly-owned subsidiary of Lexa International Corporation and, as such, Lexa International Corporation may be deemed to share beneficial ownership of the units beneficially owned by Sprague Holdings, but disclaims such beneficial ownership. Lexa International Corporation, through certain non-U.S. entities, is controlled by Antonia Ax:son Johnson and, as such, Antonia Ax:son Johnson may be deemed to share beneficial ownership of the units beneficially owned by Sprague Holdings, but disclaims such beneficial ownership.

(4) The address for this entity is 155 Spring Street, 6th Floor, New York, NY 10012.

(5) The address for this entity is 2410 Old Ivy Road, Suite 300, Charlottesville, VA 22903.

(6) The address for this person is c/o Axel Johnson AB, Villagatan 6, P.O. Box 26008, SE-100 41 Stockholm, Sweden.

(7) The address for this entity is 1800 Avenue of the Stars, Third Floor, Los Angeles, CA 90067. Kayne Anderson Capital Advisors, L.P. and Richard A. Kayne have reported that they have shared voting and dispositive power with respect to all of the 1,748,690 common units. Beneficial ownership reported based solely on a Schedule 13G filed on February 5, 2014.

(8) The address for this entity is 200 West Street, New York, NY 10282. Goldman Sachs Asset Management, L.P. has reported that it has shared voting and dispositive power with respect to all of the 754,046 common units. Goldman Sachs MLP Income Opportunities Fund, a client of Goldman Sachs Asset Management, L.P., has or may have the right to receive or the power to direct the receipt of dividends from, or the proceeds from the sale of, such common units. Beneficial ownership reported based solely on a Schedule 13G filed on February 13, 2014.

(9) The address for this entity is 100 W. Lancaster, Avenue, Suite 200, Wayne, PA 19087. Beneficial ownership reported based solely on a Schedule 13G filed on February 12, 2014.

(10) The address for this entity is 6803 S. Tuscon Way, Centennial, CO 80112. OppenheimerFunds, Inc. and Oppenheimer SteelPath MLP Income Fund have reported that they have shared voting and dispositive power with respect to 533,380 common units. Beneficial ownership reported based solely on a Schedule 13G filed on February 7, 2014.

Securities Authorized for Issuance Under Equity Compensation Plans

The following information is reported as of December 31, 2013.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of Securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders			
Equity compensation plans not approved by security holders			793,334

Our only equity compensation plan is the Sprague Resources LP 2013 Long-Term Incentive Plan, also referred to herein as the New LTIP . The New LTIP was approved by our shareholders prior to our initial public offering but has not been approved by our public shareholders. Please see Compensation Discussion and Analysis 2013 Long-Term Incentive Plan for a brief summary of the material features of the New LTIP. A more fulsome description of the terms of the New LTIP is available in our registration statement on Form S-1, last filed on October 15, 2013 under the heading Compensation Discussion and Analysis 2013 Long-Term Incentive Plan.

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Item 13. Certain Relationships, Related Transactions and Director Independence

Distributions and Payments to Sprague Holdings and Its Affiliates

The following table summarizes the distributions and payments made or to be made by us to Sprague Holdings and its affiliates in connection with our formation and ongoing operation and distributions and payments that would be made by us if we were to liquidate in accordance with the terms of our partnership agreement. These distributions and payments were determined by and among affiliated entities and, consequently, are not the result of arm s-length negotiations.

Formation Stage

The consideration given to Sprague Holdings and its affiliates for the contributions of assets and liabilities to us	1,571,970 common units;
	10,071,970 subordinated units;
	non-economic general partner interest; and
	incentive distribution rights; and

Operational Stage

Distributions of cash to Sprague Holdings and its affiliates	We will generally make cash distributions to common and subordinated unitholders, including Sprague Holdings as the holder of an aggregate of 1,571,970 common units and all of the subordinated units. Our general partner will not receive distributions on its non-economic general partner interest. If distributions exceed the minimum quarterly distribution and other higher target levels, the holders of our incentive distribution rights (currently Sprague Holdings) will be entitled to increasing percentages of the distributions, up to 50.0% of the distributions above the highest target level.
	Assuming we have sufficient distributable cash flow to pay the full minimum quarterly distribution on all of our outstanding units for four quarters, Sprague Holdings would receive an annual distribution of approximately $19.2 million on its common and subordinated units.
	If Sprague Holdings elects to reset the target distribution levels, it will be entitled to receive a certain number of common units.
Payments to our general partner and its affiliates	Our general partner will not receive any management fee or other compensation for its management of us, except as set forth in the services agreement entered into in connection with the closing of the IPO. Under the terms of the partnership

agreement, our general partner and its affiliates will be reimbursed for all expenses incurred on our behalf.

Pursuant to the terms of the services agreement, our general partner agreed to provide certain general and administrative services and operational services to us, and we agreed to

	reimburse our general partner and its affiliates for all costs and expenses incurred in connection with providing such services to us, including salary, bonus, incentive compensation, insurance premiums and other amounts allocable to the employees and directors of our general partner or its affiliates that perform services on our behalf. Neither the partnership agreement nor the services agreement limits the amount that may be reimbursed or paid by us to our general partner or its affiliates. The aggregate amount of reimbursements and fees paid by us to our general partner was $12.9 million for the period from October 30, 2013, the date of the completion of our IPO, to December 31, 2013.
Withdrawal or removal of our general partner	If our general partner withdraws or is removed, the general partner interest and its affiliates incentive distribution rights will either be sold to the new general partner for cash or converted into common units, in each case for an amount equal to the fair market value of those interests.
Liquidation Stage	
Liquidation	Upon our liquidation, our partners, including our general partner, will be entitled to receive liquidating distributions according to their respective capital account balances.

Agreements with Affiliates

In connection with the completion of our IPO on October 30, 2013, we entered into certain agreements with our sponsor and certain of its affiliates, as described below.

Omnibus Agreement

We entered into an omnibus agreement with Axel Johnson, Sprague Holdings and our general partner that will address the agreement of Axel Johnson to offer to us and to cause its controlled affiliates to offer to us opportunities to acquire certain businesses and assets and the obligation of Sprague Holdings to indemnify us for certain liabilities. This agreement is not the result of arm s-length negotiations and may not have been effected on terms at least as favorable to the parties to this agreement as could have been obtained from unaffiliated third parties. The omnibus agreement may be terminated (other than with respect to the indemnification provisions) by any party to the agreement in the event that Axel Johnson, directly or indirectly, owns less than 50% of the voting equity of our general partner.

Right of First Refusal

Under the terms of the omnibus agreement, Axel Johnson has agreed, and has caused its controlled affiliates to agree, for so long as Axel Johnson or its controlled affiliates, individually or as part of a group, control our general partner, that if Axel Johnson or any of its controlled affiliates has the opportunity to acquire a controlling interest in any assets or any business having assets that are primarily engaged in the businesses in which we are engaged as of the closing of the IPO and that operate primarily in the United States or Quebec, Ontario or the Maritimes, Canada, then Axel Johnson or its controlled affiliates will offer such acquisition opportunity to us and give us a reasonable opportunity to acquire such assets or business either before Axel Johnson or its controlled affiliates acquire it or promptly after the consummation of such acquisition by Axel Johnson or its controlled affiliates, at a price equal to the purchase price paid or to be paid by Axel Johnson or its controlled affiliates plus any related transactions costs and expenses incurred by Axel Johnson or its controlled affiliates. Our decision to acquire or not acquire any such assets or businesses will require the approval of the conflicts committee of the board of directors of our general partner. Any assets or businesses that we do not acquire pursuant to the right of first refusal may be acquired and operated by Axel Johnson or its controlled affiliates.

This right of first refusal will not apply to:

- Any acquisition of any additional interests in any assets or businesses owned by Axel Johnson or its controlled affiliates at the time of the IPO but not contributed to us in connection with the IPO, including any replacements and natural extensions thereof;

- Any investment in or acquisition of any assets or businesses primarily engaged in the businesses in which we are engaged as of the closing of the IPO and that do not operate primarily in the United States or Quebec, Ontario or the Maritimes, Canada;

- Any investment in or acquisition of a minority non-controlling interest in any assets or businesses primarily engaged in the businesses described above; or

- Any investment in or acquisition of any assets or businesses that Axel Johnson or its controlled affiliates, at the time of the closing of the IPO, are actively seeking to invest in or acquire, or have the right to invest in or acquire.

Right of Negotiation

Under the terms of the omnibus agreement, Axel Johnson has agreed and has caused its controlled affiliates to agree, for so long as Axel Johnson or its controlled affiliates, individually or as part of a group, control our general partner, that if Axel Johnson or any of its controlled affiliates decide to attempt to sell (other than to another controlled affiliate of Axel Johnson) any assets or businesses that are primarily engaged in the businesses in which we are engaged as of the closing of the IPO and that operate primarily in the United States or Quebec, Ontario or the Maritimes, Canada (including its equity interests in Kildair or any successor entities thereof and its interests in any assets or equity interests in any business that, at the time of the IPO, it is actively seeking to invest in or acquire or has the right to invest in or acquire), Axel Johnson or its controlled affiliate will notify us of its desire to sell such assets or businesses and, prior to selling such assets or businesses to a third party, will negotiate with us exclusively and in good faith for a period of 60 days in order to give us an opportunity to enter into definitive documentation for the purchase and sale of such assets or businesses on terms that are mutually acceptable to Axel Johnson or its controlled affiliate and us. If we and Axel Johnson or its controlled affiliate have not entered into a letter of intent or a definitive purchase and sale agreement with respect to such assets or businesses within such 60 days, Axel Johnson or its controlled affiliate will have the right to sell such assets or businesses to a third party following the expiration of such 60 days on any terms that are acceptable to Axel Johnson or its controlled affiliate and such third party. Our decision to acquire or not to acquire assets or businesses pursuant to this right will require the approval of the conflicts committee of the board of directors of our general partner. Our right of negotiation, to the extent it applies to any of Axel Johnson s direct or indirect equity interests in Kildair, any subsidiary of Kildair, or any entity that owns equity interests in Kildair, shall not be applicable to any transfer, assignment, foreclosure, deed-in-lieu of foreclosure, or other disposition of any such equity interests occurring as a result of the exercise of remedies by any lenders to

Kildair, any subsidiary of Kildair, or any entity that owns equity interests in Kildair.

Trade Credit Support

Under the terms of the omnibus agreement, Axel Johnson agreed to continue to provide credit support to us, consistent with past practice, through December 31, 2016, if and to the extent such services are necessary in our reasonable judgment. We will agree to use our commercially reasonable efforts to reduce, and eventually eliminate, the need for trade credit support from Axel Johnson.

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Indemnification

Under the omnibus agreement, Sprague Holdings will indemnify us for losses attributable to a failure to own any of the equity interests contributed to us in connection with the formation transactions and income taxes attributable to pre-closing operations and the formation transactions.

Services Agreement

Sprague Energy Solutions, Inc. (Sprague Solutions) and Sprague Holdings entered into a services agreement with our general partner pursuant to which our general partner will agree to provide certain general and administrative services and operational services to us and our subsidiaries, Sprague Solutions and Sprague Holdings. Pursuant to the terms of the services agreement, we agreed to reimburse our general partner and its affiliates for all costs and expenses incurred in connection with providing such services to us, including salary, bonus, incentive compensation, insurance premiums and other amounts allocable to the employees and directors of our general partner or its affiliates that perform services on our behalf. Pursuant to the terms of the services agreement, our general partner will agree to provide the same services to Sprague Solutions and Sprague Holdings, which also agreed to reimburse our general partner and its affiliates for all costs and expenses incurred in connection with providing such services.

The services agreement does not limit the amount that may be reimbursed or paid by us to our general partner or its affiliates. The amount of reimbursements and fees paid by us to our general partner was $12.9 million for the period from October 30, 2013, the date of the completion of our IPO, to December 31, 2013.

The initial term of the services agreement is five years, beginning on October 30, 2013. The agreement will automatically renew at the end of the initial term for successive one-year terms until terminated by us or by Sprague Solutions or by giving 180 days prior written notice to our general partner. The agreement will automatically terminate on the date Sprague Resources GP LLC ceases to be our general partner. The provisions of the services agreement that are applicable to Sprague Holdings may be terminated by Sprague Holdings by giving 180 days prior written notice to our general partner, and will automatically terminate on the date on which Sprague Holdings ceases to be our affiliate. The provisions of the services agreement applicable to Sprague Solutions shall automatically terminate on the date on which Sprague Solutions ceases to be a wholly owned direct or indirect subsidiary of us. The services agreement does not limit the ability of the officers and employees of our general partner to provide services to other affiliates of Sprague Holdings or unaffiliated third parties.

The services agreement is not the result of arm s-length negotiations and may not have been effected on terms at least as favorable to the parties to the agreement as could have been obtained from unaffiliated third parties.

Contribution Agreement

In connection with the IPO, we entered into a contribution, conveyance and assumption agreement, which we refer to as our contribution agreement, with Axel Johnson, Sprague Holdings, our general partner, Sprague Operating Resources LLC and certain of its subsidiaries under which, among other things, effected the transactions, including the transfer of ownership interest in our initial assets and the issuance by us to our sponsor of common units, subordinated units and the incentive distribution rights, and the use of proceedings related to our IPO.

Terminal Operating Agreement

We entered into an exclusive terminal operating agreement with Sprague Holdings and Sprague Massachusetts Properties LLC, which is a wholly owned subsidiary of Sprague Holdings, or one of its wholly owned subsidiaries, with respect to the terminal in New Bedford, Massachusetts. Pursuant to the terminal operating agreement, we were granted the exclusive use and operation of, and will retain title to all of the refined products stored at, the New Bedford terminal in exchange for a monthly fee of $15,200, subject to adjustment for changes in the Consumer Price Index for the Northeast region. This agreement is not the result of arm s-length negotiations and may not have been effected on terms at least as favorable to the parties to this agreement as could have been obtained from unaffiliated third parties.

The initial term of the terminal operating agreement is five years, beginning on October 30, 2013. Thereafter, we will have the right to extend the term for five years. Additionally, the terminal operating agreement will terminate upon 60 days written notice from Sprague Holdings or Sprague Massachusetts Properties LLC in the event that Sprague Holdings or Sprague Massachusetts Properties LLC determines that termination is necessary to facilitate the sale or development of the New Bedford terminal. The New Bedford terminal is subject to a purchase and sale agreement pursuant to which a third party may acquire the terminal from Sprague Massachusetts Properties LLC. The acquisition is subject to certain conditions that are beyond the control of Sprague Massachusetts Properties LLC. Subject to those conditions, the acquisition may be consummated on or before January 5, 2016. In the event that such sale is consummated, our terminal operating agreement with Sprague Holdings and Sprague Massachusetts Properties LLC will automatically terminate. We will not receive any proceeds from a sale of the New Bedford terminal. We do not believe that the sale will be consummated prior to December 31, 2014.

Director Independence

The NYSE does not require a publicly traded limited partnership, like us, to have a majority of independent directors on the board of directors of our general partner Nonetheless, the board of directors of our general partner has affirmatively determined that Messrs. Evans and Harper, who were appointed to the board of directors of our general partner in connection with our IPO, each satisfy the NYSE and SEC standards for independence. Sprague Holdings will appoint one additional independent director within twelve months of the date of the closing of our IPO, which occurred on October 30, 2013.

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Item 14. Principal Accounting Fees and Services

The Audit Committee has selected Ernst & Young LLP to serve as the Partnership s independent auditor for the fiscal year ending December 31, 2014. The Audit Committee in its discretion may select a different registered public accounting firm at any time during the year if it determines that such a change will be in the best interests of the Partnership and our unitholders.

Audit Fees

The following table presents fees for audit services rendered by Ernst & Young LLP for the audit of our annual consolidated financial statements for fiscal 2013, and fees billed for services rendered by Ernst & Young LLP during the same period.

	Fiscal 2013
Audit Fees(1)	$ 1,550,000
Audit-Related Fees	
Tax Fees(2)	710,000
All Other Fees	
Total	$ 2,260,000

(1) Fees for audit services billed or expected to be billed consisted of the audit of our annual financial statements, reviews of our interim financial statements and services associated with SEC registration statements and other SEC matters.

(2) Fees for tax services billed or expected to be billed consisted of services associated with the SEC registration statements, services related to tax compliance and services related to the review of our partnership Form K-1.

The Audit Committee of the Partnership was formed subsequent to the IPO, therefore in considering the nature of services provided by Ernst & Young LLP, the Board of Directors of our General Partner determined that such Fiscal 2013 services are compatible with the provisions of independent audit services. The Board of Directors discussed these services with Ernst & Young LLP and our management to determine that they are permitted under the rules and regulations concerning auditor independence promulgated by the SEC to implement the Sarbanes-Oxley Act of 2002, as well as the American Institute of Certified Public Accountants.

Policy for Approval of Audit and Non-Audit Services

Our audit committee charter requires that all services provided by our independent public accountants, both audit and non-audit, must be pre-approved by the audit committee. The pre-approval of audit and non-audit services may be given at any time up to a year before commencement of the specified service.

In determining whether to approve a particular audit or permitted non-audit service, the audit committee will consider, among other things, whether such service is consistent with maintaining the independence of the independent public accountants. The audit committee will also consider whether the independent public accountants are best positioned to provide the most effective and efficient service to us and whether the service might be expected to enhance our ability to manage or control risk or improve audit quality.

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Part IV

Item 15. Exhibits and Financial Statement Schedules

(a) Financial Statements, Financial Statement Schedules and Exhibits The following documents are filed as part of this Annual Report on Form 10-K for the year ended December 31, 2013.

1. Sprague Resources LP Audited Combined and Consolidated Financial Statements:

2. Financial Statement Schedules No schedules are included because the required information is inapplicable or is presented in the consolidated financial statements or related notes thereto.

3. Exhibits :

The list of exhibits attached to this Annual Report on Form 10-K is incorporated herein by reference.

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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this Annual Report on Form 10-K to be signed on its behalf by the undersigned, thereunto duly authorized.

Sprague Resources LP

By: Sprague Resources GP LLC, its general partner

By: /s/ David C. Glendon
David C. Glendon
President, Chief Executive Officer
(On behalf of the registrant, and in his capacity
as principal executive officer)

Date: March 27, 2014

Pursuant to the requirements of the Securities Exchange Act of 1934, this Annual Report on Form 10-K has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Michael D. Milligan Michael D. Milligan	Chairman of the Board of Directors	March 27, 2014
/s/ David C. Glendon David C. Glendon	President, Chief Executive Officer and Director (Principal Executive Officer)	March 27, 2014
/s/ Gary A. Rinaldi Gary A. Rinaldi	Senior Vice President, Chief Operating Officer and Chief Financial Officer and Director (Principal Financial Officer and Principal Accounting Officer)	March 27, 2014
/s/ Ben J. Hennelly Ben J. Hennelly	Director	March 27, 2014
/s/ Robert B. Evans Robert B. Evans	Director	March 27, 2014
/s/ C. Gregory Harper C. Gregory Harper	Director	March 27, 2014

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To The Board of Directors of Sprague Resources GP and Unitholders of Sprague Resources LP

We have audited the accompanying consolidated balance sheet of Sprague Resources LP (the Partnership) as of December 31, 2013, and the related combined and consolidated statements of operations, comprehensive (loss)/income, stockholder s/member s/unitholders equity, and cash flows for the year ended December 31, 2013, and the consolidated balance sheet of Sprague Operating Resources LLC (the Predecessor) as of December 31, 2012, and the related consolidated statements of operations, comprehensive (loss)/income, stockholder s/member s equity, and cash flows for the years ended December 31, 2012 and 2011. These financial statements are the responsibility of the Partnership s and Predecessor s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Sprague Resources LP at December 31, 2013 and the combined/consolidated results of its operations and its cash flows for the year ended December 31, 2013, and the consolidated financial position of Sprague Operating Resources LLC (the Predecessor) at December 31, 2012 and the consolidated results of its operations and its cash flows for the years ended December 31, 2012 and 2011 in conformity with U.S. generally accepted accounting principles.

/s/Ernst & Young LLP

New York, New York

March 27, 2014

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Sprague Resources LP

Consolidated Balance Sheets

	December 31, 2013	December 31, 2012 Predecessor
	(in thousands except units)	
Assets		
Current assets:		
Cash and cash equivalents	$ 998	$ 3,691
Accounts receivable, net	240,779	251,246
Inventories	348,107	472,596
Fair value of derivative assets	65,098	30,852
Deferred income taxes	2,207	14,258
Other current assets	25,369	32,858
Total current assets	682,558	805,501
Property, plant and equipment, net	116,807	177,080
Intangibles and other assets, net	16,842	20,772
Goodwill	37,383	50,894
Total assets	$ 853,590	$ 1,054,247
Liabilities and unitholders /member s equity		
Current liabilities:		
Accounts payable	$ 175,187	$ 196,776
Accrued liabilities	33,415	48,949
Fair value of derivative liabilities	130,954	49,953
Due to General Partner	4,760	
Current portion of long-term debt	126,652	317,186
Current portion of capital leases	193	709
Total current liabilities	471,161	613,573
Commitments and contingencies (Note 18)		
Long-term debt	332,848	232,007
Long-term capital leases	3,067	5,717
Other liabilities	15,015	19,208
Deferred income taxes	1,540	42,536
Total liabilities	823,631	913,041
Unitholders /member s equity:		
Predecessor s equity		146,779

Common unitholders public (8,506,666 units issued and outstanding)	127,496	
Common unitholders affiliated (1,571,970 units issued and outstanding)	(12,854)	
Subordinated unitholders affiliated (10,071,970 units issued and outstanding)	(82,356)	
Accumulated other comprehensive loss, net of tax	(2,327)	(5,573)
Total unitholders /member s equity	29,959	141,206
Total liabilities and unitholders /member s equity	$ 853,590	$ 1,054,247

The accompanying notes are an integral part of these financial statements.

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Sprague Resources LP

Combined and Consolidated Statements of Operations

	Years Ended		
	2013	**2012 Predecessor**	**2011 Predecessor**
	(dollars in thousands, except unit and per unit amounts)		
Net sales	$ 4,600,734	$ 4,043,907	$ 3,797,427
Cost of products sold	4,474,742	3,922,352	3,638,717
Gross margin	125,992	121,555	158,710
Operating costs and expenses:			
Operating expenses	51,839	47,054	42,414
Selling, general and administrative	53,580	46,449	46,292
Write-off of deferred offering costs		8,931	
Depreciation and amortization	15,452	11,665	10,140
Total operating costs and expenses	120,871	114,099	98,846
Operating income	5,121	7,456	59,864
Gain on acquisition of business		1,512	6,016
Other income (expense)	568	(160)	
Interest income	603	534	755
Interest expense	(28,695)	(23,960)	(24,049)
(Loss) income before income taxes and equity in net (loss) income of foreign affiliate	(22,403)	(14,618)	42,586
Income tax (provision) benefit	(5,097)	2,796	(16,636)
(Loss) income before equity in net (loss) income of foreign affiliate	(27,500)	(11,822)	25,950
Equity in net (loss) income of foreign affiliate		(1,009)	3,622
Net (loss) income	$ (27,500)	$ (12,831)	$ 29,572
Less: Predecessor income through October 29, 2013	$ 2,734		
Limited partners interest in net loss from October 30, 2013 to December 31, 2013	$ (30,234)		
Net loss per limited partner unit:			
Common (basic and diluted)	$ (1.50)		

Units used to compute net loss per unit:		
Common units public (basic and diluted)		8,500,000
Common units affiliated (basic and diluted)		1,571,970
Distribution declared to common and subordinated unitholders	$	5,692
Distribution declared per common and subordinated units	$	0.2825

The accompanying notes are an integral part of these financial statements.

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Sprague Resources LP

Combined and Consolidated Statements of Comprehensive (Loss) Income

	Years Ended December 31,		
	2013	2012 Predecessor	2011 Predecessor
		(in thousands)	
Net (loss) income	$ (27,500)	$ (12,831)	$ 29,572
Other comprehensive income (loss), net of tax:			
Unrealized gain (loss) on interest rate swaps			
Net loss arising in the period	(376)	(1,815)	(6,888)
Reclassification adjustment for losses realized in income	5,121	4,144	4,142
Net change in unrealized loss on interest rate swaps	4,745	2,329	(2,746)
Tax effect	(1,585)	(936)	1,103
	3,160	1,393	(1,643)
Foreign currency translation adjustment	(2,454)	928	(1,644)
Unrealized loss on inter-entity long-term foreign currency transactions	(3,500)	(1,936)	
Other comprehensive (loss) income	(2,794)	385	(3,287)
Comprehensive (loss) income	$ (30,294)	$ (12,446)	$ 26,285

The accompanying notes are an integral part of these financial statements.

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Sprague Resources LP

Combined and Consolidated Statements of Stockholder s/Member s/Unitholders Equity

(in thousands)

	Predecessor						
	Number of Shares	Common Stock	Capital in Excess of Stated Value	Retained Earnings	Stockholder s/ Member s Equity	Accumulated Other Comprehensive (Loss) Income	Total Stockholder s/ Member s Equity
	(in thousands)						
Balance, December 31, 2010	10	$ 10	$ 115,980	$ 56,865	$	$ (2,671)	$ 170,184
Net income				29,572			29,572
Other comprehensive loss						(3,287)	(3,287)
Dividend				(26,000)			(26,000)
Capital contributions			7,932				7,932
Conversion into a limited liability company	(10)	(10)	(123,912)	(60,437)	184,359		
Balance, December 31, 2011					184,359	(5,958)	178,401
Net loss					(12,831)		(12,831)
Other comprehensive income						385	385
Dividend					(26,900)		(26,900)
Capital contributions					2,151		2,151
Balance, December 31, 2012		$	$	$	$ 146,779	$ (5,573)	$ 141,206

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Sprague Resources LP

Combined and Consolidated Statements of Stockholder s/Member s/Unitholders Equity continued

(in thousands)

	Predecessor Member s Equity	Partnership Common-Public	Partnership Common-Sprague Holdings	Partnership Subordinated-Sprague Holdings	Accumulated Other Comprehensive (Loss) Income	Total
		(in thousands)				
Balance, December 31, 2012	$ 146,779	$	$	$	$ (5,573)	$ 141,206
Net income	2,734					2,734
Other comprehensive loss					(3,630)	(3,630)
Dividend	(40,000)					(40,000)
Capital contribution	18,835					18,835
Balance, October 29, 2013	128,348				(9,203)	119,145
Net assets not assumed by the Partnership	(206,085)				6,040	(200,045)
Allocation of net Parent investment to unitholders	77,737		(10,495)	(67,242)		
Proceeds from initial public offering, net		140,251				140,251
Partnership net loss		(12,758)	(2,359)	(15,117)		(30,234)
Unit-based compensation		3		3		6
Other comprehensive income					836	836
Balance, December 31, 2013	$	$ 127,496	$ (12,854)	$ (82,356)	$ (2,327)	$ 29,959

The accompanying notes are an integral part of these financial statements.

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Sprague Resources LP

Combined and Consolidated Statements of Cash Flows

	Years Ended December 31, 2013	2012 Predecessor (in thousands)	2011 Predecessor
Cash flows from operating activities			
Net (loss) income	$ (27,500)	$ (12,831)	$ 29,572
Adjustments to reconcile net (loss) income to net cash (used in) provided by operating activities:			
Depreciation and amortization	19,035	14,814	12,792
Write-off of deferred offering costs		8,931	
Gain on acquisition of business		(1,512)	(6,016)
Gain on sale of assets and insurance recoveries	(779)	(487)	(18)
Impairments of terminal asset		529	
Provision for doubtful accounts	887	591	1,765
Undistributed loss (income) on investment of foreign affiliate		1,009	(3,622)
Non-cash unit based compensation	6		
Deferred income taxes	(7,433)	(5,389)	5,707
Changes in assets and liabilities, net of effects of contribution agreement:			
Accounts receivable	(172,094)	24,160	19,190
Inventories	57,783	54,373	(73,339)
Prepaid expenses and other current assets	1,683	19,216	(881)
Fair value of commodity derivative instruments	50,838	27,208	(39,675)
Due to/from General Partner and affiliates	4,760		
Accounts payable, accrued liabilities and other	(6,641)	32,517	10,664
Net cash (used in) provided by operating activities	(79,455)	163,129	(43,861)
Cash flows from investing activities			
Purchases of property, plant and equipment	(22,079)	(7,293)	(7,255)
Proceeds from property insurance settlement	1,867		
Loan to foreign affiliate			(1,958)
Acquisitions, net of cash acquired	(20,700)	(73,036)	(7,845)
Proceeds from sale of assets	172	636	54
Net cash used in investing activities	(40,740)	(79,693)	(17,004)
Cash flows from financing activities			
Net borrowings (payments) under credit agreements	34,646	(107,822)	116,300
Borrowings of unsecured debt		25,000	
Payments on capital lease liabilities and term debt	(2,253)	(1,346)	(499)
Payments on long-term terminal obligations	(459)	(668)	(608)

Debt issue costs		(13,667)		(422)		(181)
Dividend paid to Parent		(40,000)		(26,900)		(26,000)
Capital contribution from Parent		10,000				
Proceeds from initial public offering		140,251				
Cash distribution to Parent in connection with initial public offering		(10,038)				
Predecessor cash retained by Parent		(205)				
Net (decrease) increase in payable to Parent		(641)		598		(130)
Net cash provided by (used in) financing activities		117,634		(111,560)		88,882
Effect of exchange rate changes on cash balances held in foreign currencies		(132)		(14)		(42)
Net change in cash and cash equivalents		(2,693)		(28,138)		27,975
Cash and cash equivalents, beginning of year		3,691		31,829		3,854
Cash and cash equivalents, end of year	$	998	$	3,691	$	31,829
Supplemental disclosure of cash flow information						
Cash paid:						
Interest	$	25,015	$	20,977	$	19,839
Taxes	$	3,206	$	2,831	$	3,321

The accompanying notes are an integral part of these financial statements.

Sprague Resources LP

Notes to Combined and Consolidated Financial Statements

(in thousands unless otherwise stated)

1. Description of Business and Summary of Significant Accounting Policies

Company Businesses

Sprague Resources LP (the Partnership) is a Delaware limited partnership formed on June 23, 2011 to engage in any lawful activity for which limited partnerships may be organized under the Delaware Revised Limited Partnership Act including, but not limited to, actions to form a limited liability company and/or acquire assets owned by Sprague Operating Resources LLC, a Delaware limited liability company and the Partnership s operating company (the Predecessor and OLLC), an entity engaged in the sale of energy products, as well as materials handling operations.

Unless the context otherwise requires, references to Sprague Resources, and the Partnership, when used in a historical context prior to October 30, 2013, refer to Sprague Operating Resources LLC, the Predecessor for accounting purposes and the successor to Sprague Energy Corp., also referenced as the Predecessor and when used in the present tense or prospectively, refer to Sprague Resources LP and its subsidiaries. Unless the context otherwise requires, references to Axel Johnson or the Parent refer to Axel Johnson Inc. and its controlled affiliates, collectively, other than Sprague Resources, its subsidiaries and its general partner. References to Sprague Holdings refer to Sprague Resources Holdings LLC, a wholly owned subsidiary of Axel Johnson and the owner of the General Partner. References to the general partner refer to Sprague Resources GP LLC.

The Partnership is one of the largest independent wholesale distributors of refined products in the Northeast United States based on aggregate terminal capacity. The Partnership owns and/or operates a network of 15 refined products and materials handling terminals located in the Northeast United States. The Partnership also utilizes third-party terminals in the Northeast through which it sells or distributes refined products pursuant to rack, exchange and throughput agreements. The Partnership has four business segments: refined products, natural gas, materials handling and other operations. The refined products segment purchases a variety of refined products, such as heating oil, diesel, residual fuel oil, kerosene, jet fuel and gasoline (primarily from refining companies, trading organizations and producers), and sells them to wholesale and commercial customers. The natural gas segment purchases, sells and distributes natural gas to commercial and industrial customers in the Northeast and Mid-Atlantic. The Partnership purchases the natural gas it sells from natural gas producers and trading companies. The materials handling segment offloads, stores and prepares for delivery a variety of customer-owned products, including asphalt, clay slurry, salt, gypsum, coal, petroleum coke, caustic soda, tallow, pulp and heavy equipment. The Partnership s other operations include the purchase and distribution of coal and certain commercial trucking activities.

Since 2007 and through September 30, 2012, the Predecessor, through its wholly-owned foreign subsidiary, Sprague Energy Canada Ltd., owned a 50% equity investment in 9047-1137 Quebec Inc. (Kildair). On October 1, 2012, the Predecessor acquired the remaining 50% equity interest in Kildair (see Note 3). Kildair s primary business is the distribution of residual fuel oil and asphalt which are included in the refined products segment. Kildair s results of operations are not included in the results of the Partnership s operations as discussed below.

In connection with the completion on October 30, 2013 of the initial public offering (the IPO) of limited partner interests of the Partnership, Axel Johnson Inc. (the Parent or Axel Johnson) contributed to Sprague Resources

Holdings LLC (Sprague Holdings) all of the ownership interests in the Predecessor. The Predecessor distributed to a wholly owned subsidiary of Sprague Holdings certain assets and liabilities, including among others, the equity investment in Kildair and accounts receivable and cash in an aggregate amount equal to the net proceeds of the IPO. Sprague Holdings then contributed all of the ownership interests in the Predecessor to the Partnership. All of the assets and liabilities of the Predecessor contributed to the Partnership by Sprague Holdings were recorded at the Parent s historical cost, as the foregoing transactions are among entities under common control. See Note 2 Initial Public Offering. Kildair is not included in the Partnership s consolidated financial statements effective October 30, 2013, the IPO date, at which time Kildair was distributed to an affiliate of the Parent.

Basis of Presentation

The consolidated financial statements include the accounts of the Partnership commencing October 30, 2013, and the Predecessor and its wholly-owned subsidiaries through October 30, 2013. Intercompany transactions between the Partnership, Predecessor and its subsidiaries have been eliminated. Investments in affiliated companies, greater than 20% voting interest or where the Partnership or Predecessor exerts significant influence over an investee but lacks control over the investee are accounted for using the equity method. For the year ended December 31, 2013, the financial statements for the Partnership and the Predecessor are presented on a combined basis as the entities remain under common control.

Use of Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities in the balance sheet and the reported revenues and expenses in the income statement. Actual results could differ from those estimates. Among the estimates made by management are asset valuations, the fair value of derivative assets and liabilities, environmental and legal obligations and income taxes.

Revenue Recognition and Cost of Products Sold

The Partnership recognizes revenue on refined products, natural gas and materials handling revenue-producing activities, net of applicable provisions for discounts and allowances. Allowances for cash discounts are recorded as a reduction of revenue at the time of sale. Cash discounts were $7.3 million, $7.5 million and $6.8 million for the years ended December 31, 2013, 2012 and 2011, respectively. At the time of sale for all revenue producing activities, persuasive evidence of an arrangement exists, delivery or service has occurred, the price is determinable and collectability is reasonably assured.

Refined products revenue-producing activities are direct sales to customers including throughput and exchange locations. Revenue is recognized when the product is delivered. Revenue is not recognized on exchange agreements, which are entered into primarily to acquire refined products by taking delivery of products closer to the Partnership s end markets. Net differentials or fees for exchange agreements are recorded within cost of products sold. Natural gas revenue-producing activities are direct sales to customers at various points on natural gas pipelines or at local distribution companies (*i.e.*, utilities). Revenue is recognized when the product is delivered. Materials handling service revenue is recognized monthly over the contractual service period or when the service is rendered. Revenue from other activities, primarily coal distribution and transportation services, is recognized when the product is delivered or the services are rendered.

The allowance for doubtful accounts is recorded to reflect an estimate of the ultimate realization of the Partnership accounts receivable and includes an assessment of customers creditworthiness and the probability of collection. The allowance reflects an estimate of specifically identified accounts at risk. The provision for the allowance for doubtful accounts is included in cost of products sold.

Shipping costs that occur at the time of sale are included in cost of products sold. Various excise taxes collected at the time of sale and remitted to authorities are recorded on a net basis.

Commodity Derivatives

The Partnership utilizes derivative instruments consisting of futures contracts, forward contracts, swaps, options and other derivatives individually or in combination, to mitigate its exposure to fluctuations in prices of refined petroleum products and natural gas. On a limited basis and within the Partnership s risk management guidelines, the Partnership utilizes futures contracts, forward contracts, swaps, options and other derivatives to generate profits from changes in market prices. The Partnership invests in futures and over-the-counter (OTC) transactions either on regulated exchanges or in the OTC market. Futures contracts are exchange-traded contractual commitments to either receive or deliver a standard amount or value of a commodity at a specified future date and price, with some futures contracts based on cash settlement rather than a delivery requirement. Futures exchanges typically require investors to provide margin deposits as security. OTC contracts, which may or may not require margin deposits as security, involve parties that have agreed either to exchange cash payments or deliver or receive the underlying commodity at a specified future date and price. The Partnership posts initial margin with futures transaction brokers, along with variation margin, which is paid or received on a daily basis, and is included in other current assets in the Consolidated Balance Sheets. In addition, the Partnership may either pay or receive margin based upon exposure with counterparties. Payments made by the Partnership are included in other current assets, whereas payments received by the Partnership are included in accrued liabilities in the Consolidated Balance Sheets. Substantially all of the Partnership s commodity derivative contracts outstanding as of December 31, 2013 will settle prior to June 30, 2015.

The Partnership enters into some master netting arrangements to mitigate credit risk with significant counterparties. Master netting arrangements are standardized contracts that govern all specified transactions with the same counterparty and allow the Partnership to terminate all contracts upon occurrence of certain events, such as a counterparty s default. The Partnership has elected not to offset the fair value of its derivatives, even where these arrangements provide the right to do so.

The Partnership s derivative instruments are recorded at fair value, with changes in fair value recognized in net income (loss) or comprehensive income (loss) each period as appropriate. The Partnership s fair value measurements are determined using the market approach and includes non-performance risk and time value of money considerations. Counterparty credit is considered for receivable balances, and the Partnership s credit is considered for payable balances.

The Partnership does not offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against the fair value of derivative instruments executed with the same counterparty under the same master netting arrangement. The Partnership had no right to reclaim or obligation to return cash collateral as of December 31, 2013 or 2012.

Interest Rate Derivatives

The Partnership manages its exposure to variable LIBOR borrowings by using interest rate swaps to convert a portion of its variable rate debt to fixed rates. These interest rate swaps are designated as cash flow hedges and the effective portion of changes in fair value of the swaps are included as a component of comprehensive income and accumulated other comprehensive loss, net of tax, in the Consolidated Statements of Comprehensive (Loss) Income and in the Consolidated Balance Sheets, respectively. The ineffective portion of the changes in fair value of the swaps, which was not material, is recorded in earnings.

To designate a derivative as a cash flow hedge, the Partnership documents at inception the assessment that the derivative will be highly effective in offsetting expected changes in cash flows from the item hedged. The assessment, updated at least quarterly, is based on the most recent relevant historical correlation between the derivative and the item hedged. If during the term of the derivative, the hedge is found to be less than highly effective, hedge accounting is prospectively discontinued and the remaining gains and losses are reclassified to income in the current period.

Market and Credit Risk

The Partnership manages the risk of market fluctuations in the price and transportation costs of its commodities through the use of derivative instruments. The volatility of prices for energy commodities can be significantly influenced by market supply and demand, changes in seasonal demand, weather conditions, transportation availability, and federal and state regulations. The Partnership monitors and manages its exposure to market risk on a daily basis in accordance with approved policies.

The Partnership has a number of financial instruments that are potentially at risk including cash and cash equivalents, receivables and derivative contracts. The Partnership s primary exposure is credit risk related to its receivables and counterparty performance risk related to the fair value of derivative assets, which is the loss that may result from a customer s or counterparty s non-performance. The Partnership uses credit policies to control credit risk, including utilizing an established credit approval process, monitoring customer and counterparty limits, employing credit mitigation measures such as analyzing customer financial statements, and accepting personal guarantees and various forms of collateral.

The Partnership believes that the counterparties to its derivative contracts will be able to satisfy their contractual obligations. Credit risk is limited by the large number of customers and counterparties comprising the Partnership s business and their dispersion across different industries.

The Partnership s cash is in demand deposit and other short-term investment accounts placed with federally insured financial institutions. Such deposit accounts at times may exceed federally insured limits. The Partnership has not experienced any losses on such accounts.

Fair Value Measurements

The Partnership s derivative instruments are recorded at fair value, with changes in fair value recognized in net income or other comprehensive income each period as appropriate. The Partnership s fair value measurements are determined using the market approach and includes non-performance risk and time value of money considerations. Counterparty credit is considered for receivable balances, and the Partnership s credit is considered for payable balances.

The Partnership determines fair value in accordance with Accounting Standards Codification (ASC) 820, *Fair Value Measurement* which established a hierarchy for the inputs used to measure the fair value of financial assets and liabilities based on the source of the input, which generally range from quoted prices for identical instruments in a principal trading market (Level 1) to estimates determined using significant unobservable inputs (Level 3). Multiple inputs may be used to measure fair value, however, the level of fair value is based on the lowest significant input level within this fair value hierarchy.

Details on the methods and assumptions used to determine the fair values are as follows:

Fair value measurements based on Level 1 inputs: Measurements that are most observable and are based on quoted prices of identical instruments obtained from the principal markets in which they are traded. Closing prices are both readily available and representative of fair value. Market transactions occur with sufficient frequency and volume to assure liquidity.

Fair value measurements based on Level 2 inputs: Measurements derived indirectly from observable inputs or from quoted prices from markets that are less liquid are considered Level 2. Measurements based on Level 2 inputs include over-the-counter derivative instruments that are priced on an exchange traded curve, but have contractual terms that are not identical to exchange traded contracts. The Partnership utilizes fair value measurements based on Level 2 inputs for its fixed forward contracts, over-the-counter commodity price swaps, interest rate swaps and forward currency contracts.

Fair value measurements based on Level 3 inputs: Measurements that are least observable are estimated from significant unobservable inputs determined from sources with little or no market activity for comparable contracts or for positions with longer durations.

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Earnings (Loss) Per Unit

The Partnership computes income per unit using the two-class method. Net income (loss) attributable to common unitholders and subordinated unitholders for purposes of the basic income (loss) per unit computation is allocated between the common unitholders and subordinated unitholders by applying the provisions of the partnership agreement. Under the two-class method, any excess of distributions declared over net income is allocated to the partners based on their respective sharing of income specified in the partnership agreement. Net income (loss) per unit is determined by dividing the net income allocated to the common unitholders and the subordinated unitholders under the two-class method by the number of common units and subordinated units outstanding at December 31, 2013.

Sprague Holdings owns all of the outstanding subordinated units and the incentive distribution rights (IDR) as of December 31, 2013. Pursuant to the partnership agreement, to the extent that the quarterly distributions exceed certain targets, Sprague Holdings is entitled to receive certain incentive distributions that will result in more net income proportionately being allocated to Sprague Holdings than to the other holders of common units.

Financial Accounting Standards Board (FASB) Accounting Standards Codification 260 (ASC 260) *Earnings per Share* addresses the computation of earnings per share by entities that have issued securities other than common stock that contractually entitle the holder to participate in dividends and earnings of the entity. The application of ASC 260 may have an impact on earnings per limited partner unit in future periods if there are material differences between net income and actual cash distributions or if other participating units are issued.

Cash and Cash Equivalents

Cash and cash equivalents include cash and highly liquid investments which are readily convertible into cash and have maturities of three months or less when purchased.

Inventories

The Partnership s inventories are valued at the lower of cost or market. Cost is primarily determined using the first-in, first-out method, except for Kildair, the Predecessor s Canadian subsidiary, which used the weighted average method. Inventory consists of petroleum products, natural gas, asphalt and coal. The Partnership uses derivative instruments, primarily futures, forwards and swaps, to economically hedge substantially all of its inventory.

Property, Plant and Equipment, Net

Property, plant and equipment, net are recorded at historical cost. Depreciation is computed on a straight-line basis over the following estimated useful lives:

Information technology equipment and software	3 to 7 years
Furniture and fixtures	5 to 10 years
Plant, machinery and equipment	5 to 30 years
Building and leasehold improvements	10 to 25 years

Leasehold improvements are amortized over the term of the lease or the estimated useful life of the improvement, whichever is shorter. Maintenance and repairs are charged to expense as incurred. Costs and related accumulated depreciation of properties sold or otherwise disposed of are removed from the respective accounts, and any resulting gains or losses are recorded at that time.

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Long-lived Assets

The Partnership evaluates the carrying value of its property, plant and equipment and certain intangible assets for impairment when events or changes in circumstances indicate the carrying amount may not be recoverable based on estimated future undiscounted cash flows. Future cash flow projections include assumptions of future sales levels, the impact of cost reduction programs, and the level of working capital needed to support each business. To the extent the carrying amount is not recoverable based on undiscounted cash flows, the amount of impairment is measured by the difference between the carrying value and the fair value of the asset. During the year ended December 31, 2012, the Predecessor recorded an impairment of $0.5 million in connection with a terminal closure. No impairment charges were recorded for the years ended December 31, 2013 and 2011.

Purchase Price Allocation

The Predecessor has made a number of acquisitions in the past and the Partnership may continue to make acquisitions in the future. The Partnership and the Predecessor allocate the cost of the acquired entity to the assets acquired and liabilities assumed based on their respective fair values at the date of acquisition. Long-lived assets (principally property, plant and equipment and goodwill) generally represent large components of these acquisitions. In addition to goodwill, intangible assets acquired have included customer relationships and non-compete agreements. Goodwill is calculated as the excess of the cost of the acquired entity over the net of the fair value of the assets acquired and the liabilities assumed. Customer relationships and non-compete agreements are valued based on an excess earnings or income approach based on projected cash flows.

Other assets acquired and liabilities assumed typically include, but are not limited to, inventory, accounts receivable, accounts payable and other working capital items. Because of their short-term nature, the fair values of these other assets and liabilities generally approximate the book values on the acquired entity s balance sheet.

Goodwill

Goodwill is not amortized but tested for impairment at the reporting unit level, at least annually (as of October 31 each year), by determining the fair value of the reporting unit and comparing it to its carrying value. The Partnership assesses the fair value of its reporting units based on a discounted cash flow valuation model (Level 3 measurement). The key assumptions used are discount rates and growth rates, applied to cash flow projections. These assumptions contemplate business, market and overall economic conditions.

After applying the discounted cash flow methods to measure the fair value of its reporting units, including the consideration of reasonably likely adverse changes in the rates and assumptions described above, the Partnership determined that there have been no goodwill impairments to date. In performing the discounted cash flow analysis, the Partnership used a range of discount rate assumptions to evaluate the sensitivity on the fair values resulting from the discounted cash flow valuation.

Intangibles and Other Assets, Net

Intangibles and other assets, net consist of intangible assets with finite lives, including deferred debt issuance costs, customer relationships and covenants not to compete. Intangibles and other assets are amortized over their respective estimated useful lives. The Partnership evaluates its intangible and other long-lived assets for impairment when indicators are present.

Income Taxes

The Partnership is organized as a pass-through entity for U.S. federal income tax purposes. As a result, the partners are responsible for federal income taxes based on their respective share of taxable income. Net income for financial statement purposes may differ significantly from taxable income reportable to unitholders as a result of differences between the tax bases and financial reporting bases of assets and liabilities and the taxable income allocation requirements under the partnership agreement. The Partnership, however, is subject to a statutory requirement that non-qualifying income cannot exceed 10% of total gross income, determined on a calendar year basis under the applicable income tax provisions. If the amount of non-qualifying income exceeds this statutory limit, the Partnership would be taxed as a corporation. Accordingly, certain activities that generate non-qualifying income are conducted through a taxable corporate subsidiary, Sprague Energy Solutions, Inc. Sprague Energy Solutions, Inc. is subject to federal and state income tax and pays any income taxes related to the results of its operations. For the year ended December 31, 2013, the Partnership s non-qualifying income did not exceed the statutory limit. The Partnership is subject to income tax and franchise tax in certain domestic state and local jurisdictions.

Prior to the IPO, the Predecessor was not a separate taxable entity for U.S. federal and certain state income tax purposes and its results were included in the consolidated U.S. federal and certain state income tax returns of Lexa International Corporation, which is the sole shareholder of the Predecessor s Parent. Income tax provisions and benefits, related tax payments, and current and deferred tax balances were prepared as if the Predecessor operated as a stand-alone taxpayer for all periods presented in accordance with the tax sharing agreement between the Predecessor and the Parent. Under the tax sharing agreement, the Predecessor is obligated to pay federal and certain state taxes to the Parent. In the event that the Parent does not have a consolidated liability for federal or certain state taxes, the Predecessor is not obligated to pay the Parent for such taxes and all such amounts are reflected as capital contributions.

Income taxes are provided using the asset and liability method prescribed by ASC 740, *Income Taxes*. Under this method, income taxes (*e.g*., deferred tax assets, deferred tax liabilities and taxes currently payable and tax expense) are recorded based on amounts refundable or payable in the current year and include the impact of temporary differences between the amount of assets and liabilities recognized for financial reporting purposes and such amounts recognized for tax purposes. Deferred taxes are measured by applying currently enacted tax rates. The Partnership establishes a valuation allowance for deferred tax assets when it is more likely than not that these assets will not be realized.

The Partnership recognizes the financial statement effect of a tax position only when management believes that it is more likely than not, that based on the technical merits, the position will be sustained upon examination. The Partnership classifies interest and penalties associated with uncertain tax positions as income tax expense.

Foreign Currency

The functional currency of the Predecessor s foreign subsidiary, which owns Kildair, is the Canadian dollar. All balance sheet asset and liability accounts of the Predecessor s foreign subsidiary are translated to U.S. dollars using rates of exchange in effect at the balance sheet dates, and its results of operations are translated using average exchange rates for the relevant period. Resulting translation adjustments are recorded as a component of member s equity in accumulated other comprehensive loss.

Kildair converts receivables and payables denominated in other than their functional currency at the exchange rate as of the balance sheet date. Kildair utilizes forward currency contracts to manage its exposure to currency fluctuations of certain of its transactions that are denominated in U.S. dollars. These forward currency exchange contracts are recorded at fair value at the balance sheet date and changes in fair value are recognized in net income as these forward currency contracts have not been designated as hedges. For the period January 1, 2013 to October 29, 2013 and for the year ended December 31, 2012, transaction exchange gains or losses, except for certain transaction gains or losses related to intercompany receivable and payables, amounted to losses of $3.8 million and $1.4 million, respectively, the majority of which is recorded in cost of products sold in the Consolidated Statements of Operations. The Predecessor s transaction exchange gains or losses were not significant for the year ended December 31, 2011.

Transaction gains and losses related to intercompany receivables and payables not anticipated to be settled in the foreseeable future are excluded from the determination of net income and are recorded as a translation adjustment to accumulated other comprehensive (loss) income as a component of member s equity.

Recent Accounting Pronouncements

In February 2013, the FASB issued ASU No. 2013-02, *Reporting Amounts Reclassified Out of Accumulated Other Comprehensive Income,* which amends ASC 220, *Comprehensive Income*. The amended guidance requires entities to provide information about the amounts reclassified out of accumulated other comprehensive income by component. Additionally, entities are required to present, either on the face of the financial statements or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income. The amended guidance does not change the current requirements for reporting net income or other comprehensive income. The Predecessor adopted ASU 2013-02 as of January 1, 2013 and it did not have a material impact on the consolidated financial statements. Prior periods have been reclassified to conform to the current period presentation reflecting the impact of the adoption of ASU 2013-02.

In December 2011, the FASB issued ASU 2011-11, *Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities.* ASU 2011-11 requires an entity to disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. Entities are required to disclose both gross and net information about these instruments. ASU 2011-11 is effective for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods. The Predecessor adopted ASU 2011-11 as of January 1, 2013 and it did not have a material impact on the consolidated financial statements, but did result in additional disclosure regarding fair value measurement. See Note 17.

2. Initial Public Offering

On October 30, 2013, in connection with the closing of the IPO, 8,500,000 of the Partnership s common units, representing a 42.2% limited partner interest in the Partnership, were sold to the public at an initial public offering price of $18.00 per unit. Net proceeds of the sale of the common units were $140.3 million after deducting underwriting discounts and commissions, the structuring fee and offering expenses. As of December 31, 2013, Sprague Holdings owns 1,571,970 common units and 10,071,970 subordinated units, representing an aggregate 57.8% limited partner interest in the Partnership.

The following table is a reconciliation of cash proceeds from the IPO (in millions):

Gross proceeds	$ 153.0
Less: Underwriting and structuring fees and other offering expenses	(12.7)
Net proceeds from the IPO used for reduction of working capital facility	$ 140.3

Sprague Holdings owns, directly or indirectly, all of the Partnership s subordinated units. The principal difference between the Partnership s common units and subordinated units is that during the subordination period, the common units have the right to receive distributions of cash from distributable cash flow each quarter in an amount equal to $0.4125 per common unit, which is the amount defined in the partnership agreement as the minimum quarterly distribution, plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, before any distributions of cash from distributable cash flow may be made on the subordinated units. Furthermore, no arrearages will accrue or be paid on the subordinated units. Upon expiration of the subordination period, any outstanding arrearages in payment of the minimum quarterly distribution on the common units will be extinguished (not paid), each outstanding subordinated unit will immediately convert into one common unit and will thereafter participate pro rata with the other common units in distributions.

Sprague Holdings currently holds incentive distribution rights that entitle it to receive increasing percentages, up to a maximum of 50.0%, of the cash the Partnership distributes from operating surplus (as defined below) in excess of $0.474375 per unit per quarter. The maximum distribution of 50.0% does not include any distributions that Sprague Holdings may receive on any limited partner units that it owns.

The partnership agreement contains provisions for the allocation of net income and loss to the unitholders. For purposes of maintaining partner capital accounts, the partnership agreement specifies that items of income and loss shall be allocated among the partners in accordance with their respective percentage interest. Normal allocations according to percentage interests are made after giving effect, if any, to priority income allocations in an amount equal to incentive cash distributions allocated 100% to Sprague Holdings.

Contribution, Conveyance and Assumption Agreement

On October 30, 2013, in connection with the closing of the IPO, the Parent, Sprague Holdings, the Partnership, Sprague Resources GP LLC, a Delaware limited liability company and the general partner of the Partnership (the General Partner), Sprague Massachusetts Properties LLC, a Delaware limited liability company and a wholly owned subsidiary of Sprague Holdings (Sprague Massachusetts), Sprague International Properties LLC, a Delaware limited liability company and a wholly owned subsidiary of Sprague Holdings (Sprague International), Sprague Canadian Properties LLC, a Delaware limited liability company and a wholly owned subsidiary of Sprague International (Sprague Canadian) and the OLLC entered into a contribution, conveyance and assumption agreement (the Contribution Agreement). Pursuant to the Contribution Agreement, among other things, Sprague Holdings conveyed all of the ownership interests in the Predecessor to the Partnership (through the OLLC), in exchange for (a) 1,571,970 common units, representing a 7.8% limited partner interest in the Partnership, (b) 10,071,970 subordinated units, representing a 50% limited partner interest in the Partnership, (c) all of the equity interests in the Partnership classified as incentive distribution rights under the amended and restated agreement of limited partnership of the Partnership and (d) the right to receive the deferred issuance and distribution (as defined in the Contribution Agreement).

Omnibus Agreement

On October 30, 2013, in connection with the closing of the IPO, the Partnership, the Parent, Sprague Holdings and the General Partner, entered into an omnibus agreement (the Omnibus Agreement). The Omnibus Agreement addresses the agreement of the Parent to offer to the Partnership, and to cause the Parent s controlled affiliates to offer to the Partnership, opportunities to acquire certain businesses and assets and the obligation of Sprague Holdings to indemnify the Partnership for certain liabilities. Pursuant to the Omnibus Agreement, the Parent agreed to continue to provide credit support to the Partnership, consistent with past practice, through December 31, 2016, if and to the extent such services are necessary and reasonable, and the Partnership agreed to use its commercially reasonable efforts to reduce, and eventually eliminate, the need for trade credit support from the Parent. As of December 31, 2013, Axel Johnson provided the Partnership with approximately $80.2 million of outstanding trade credit support. The Omnibus Agreement may be terminated (other than with respect to the indemnification provisions) by any party to the Omnibus Agreement in the event that the Parent, directly or indirectly, owns less than 50% of the voting equity power of the General Partner.

Services Agreement

On October 30, 2013, in connection with the closing of the IPO, the Partnership, the General Partner and Sprague Holdings, entered into an operational services agreement (the Services Agreement). Pursuant to the Services Agreement, the General Partner will provide certain general and administrative and operational services to the Partnership and Sprague Holdings, and the Partnership and Sprague Holdings will reimburse the General Partner for all costs and expenses incurred in connection with providing such services to the Partnership and Sprague Holdings. The Services Agreement does not limit the amount that may be reimbursed or paid by the Partnership to the General Partner. The initial term of the Services Agreement will expire on October 30, 2018.

The Services Agreement will automatically renew at the end of the initial term for successive one-year terms until terminated in accordance with the terms thereof. The Services Agreement does not limit the ability of the officers and employees of the General Partner to provide services to other affiliates of Sprague Holdings or unaffiliated third parties. See Note 12 Related Party Transactions.

Long-Term Incentive Plan

The General Partner adopted the Sprague Resources LP 2013 Long-Term Incentive Plan (the LTIP) effective immediately prior to the effective date of the IPO, for the benefit of employees, consultants and directors of the General Partner and its affiliates, who provide services to the General Partner or an affiliate. The LTIP provides the Partnership with the flexibility to grant unit options, restricted units, phantom units, unit appreciation rights, cash awards, distribution equivalent rights, substitute awards and other unit-based awards or any combination of the foregoing.

The LTIP limits the number of common units that may be delivered, pursuant to vested awards, to 800,000 common units. On January 1 of each calendar year occurring after the second anniversary of the effective date and prior to the expiration of the LTIP, the total number of common units reserved and available for issuance under the LTIP will increase by 200,000 common units.

The LTIP will expire upon the earlier of (i) its termination by the board of directors of the General Partner, (ii) the date common units are no longer available under the LTIP for grants or (iii) the tenth anniversary of the date the LTIP was approved by the General Partner.

3. Business Combinations
Bridgeport Terminal

On July 31, 2013, the Predecessor purchased an oil terminal in Bridgeport, Connecticut for $20.7 million. This deep water facility includes 13 storage tanks with 1.3 million barrels of storage capacity for gasoline and distillate products with 12 storage tanks and 1.1 million barrels currently in service. The terminal will provide throughput services to third-parties for branded gasoline sales, and is expected to increase the Predecessor s marketing of refined products, both gasoline and distillate, in the Connecticut market.

The acquisition was accounted for as a business combination and was financed with a capital contribution of $10.0 million from the Parent (see Note 12 Related Party Transactions) and $10.7 million of borrowings under the acquisition line of the Predecessor s credit facility.

The following table summarizes the fair values of the assets acquired:

Property, plant and equipment	$ 20,190
Intangible assets customer relationships	510
Net assets acquired	$ 20,700

The Predecessor incurred $0.2 million of acquisition related costs that were recorded as selling, general and administrative expense at the acquisition date.

Kildair

Prior to October 1, 2012

In October 2007, the Predecessor purchased a 50% equity interest in Kildair for $38.7 million. The share purchase agreement provided for the Predecessor to acquire the remaining 50% of Kildair in 2012, subject to terms and conditions within the discretion of the Predecessor, for an additional $27.5 million Canadian, plus a potential earn-out payment if EBITDA over the five year period exceeded $55.0 million Canadian. The difference between the acquisition cost and the fair value of net assets acquired in October 2007 of $13.2 million was allocated to various assets and liabilities based on their respective fair values with amortization recorded over the useful lives of the assets or liabilities that gave rise to the difference. Through September 30, 2012, the investment in Kildair was accounted for using the equity method of accounting and the Predecessor s share of its results were recorded as equity in net loss of foreign affiliate in the Consolidated Statements of Operations.

Summary financial information for Kildair, not adjusted for the percentage of ownership held by the Predecessor, follows:

	From January 1, 2012 through September 30, 2012	For the Year Ended December 31, 2011
Net sales	$ 418,203	$ 633,099
Gross profit	13,571	36,460
Income from operations	1,865	15,200
Net (loss) income	(1,417)	7,470

The Predecessor s equity share of earnings from its investment in Kildair, which includes amortization of the excess of the fair value over the cost of the assets acquired, was a loss of $1.0 million, net of tax, for the period from January 1, 2012 to September 30, 2012 and was income of $3.6 million, net of tax, for the year ended December 31, 2011.

From October 1, 2012 through October 30, 2013

On October 1, 2012 (the acquisition date), the Predecessor acquired control of Kildair by purchasing the remaining 50% equity interest. Since the acquisition date, the assets, liabilities and results of operations of Kildair have been consolidated into the Predecessor s consolidated financial statements. Kildair is not included in the Partnesrship s consolidated financial statements effective October 30, 2013, the IPO date, at which time Kildair was distributed to an affiliate of the Parent.

Kildair has 3.2 million barrels of storage capacity and an infrastructure that includes an asphalt plant, loading racks, testing laboratory and a marine dock on the St. Lawrence River. The purchase of this facility augments the Predecessor s supply, storage and marketing opportunities and provides new opportunities in asphalt marketing and expanded materials handling capabilities. The acquisition-date fair value of the consideration consisted of cash of $73.0 million (including an $8.7 million redemption of preferred shares) and the Predecessor s previous 50% equity interest. The Predecessor recognized a gain of $1.5 million as a result of re-measuring to fair value its prior equity interest held before the business combination. The gain is calculated as the difference between the acquisition-date fair value ($57.0 million) and the book value immediately prior to the acquisition date ($55.5 million). The book value of the equity interest included currency translation adjustment balances in accumulated other comprehensive loss. The fair value was determined using valuation techniques including the discounted cash flow approach and the market multiple approach (enterprise value of earnings before interest, taxes, depreciation and amortization). The discounted cash flow approach incorporates assumptions including estimated future cash flows and a discount rate that reflects consideration of risk free rates as well as market risk.

The market multiple approach incorporates market information from comparable companies. The gain, which resulted in no income tax expense, was recorded in 2012 as gain on acquisition of a business in the Consolidated Statements of

Operations.

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The following table summarizes the fair values of the assets acquired and liabilities assumed at the acquisition date:

Accounts receivable	$ 47,050
Inventory	126,796
Other current assets	24,255
Property, plant and equipment	71,943
Intangible assets	13,947
Total identifiable assets acquired	283,991
Current liabilities	54,975
Debt	92,370
Other liabilities	19,210
Contingencies	
Total liabilities assumed	166,555
Net identifiable assets acquired	117,436
Goodwill	12,611
Net assets acquired	$ 130,047

The Predecessor determined the fair value of property, plant and equipment using the replacement cost approach and determined the fair value of intangible assets using income approaches that incorporated projected cash flows and relief from royalty methodologies. The Predecessor s analysis of fair value factors indicated that for substantially all other assets and liabilities that book value approximated fair value.

The goodwill recognized is primarily attributable to Kildair s assembled workforce, its reputation in Eastern Canada and the Northeast United States and the residual cash flow the Predecessor believes that it will be able to generate. None of the goodwill is expected to be deductible for income tax purposes.

The Predecessor recognized $0.3 million of acquisition related costs that were expensed in 2012 and are included in selling, general and administrative expense in the accompanying Consolidated Statements of Operations.

The amount of net sales and net loss of Kildair included in the Predecessor s Consolidated Statements of Operations for the period from October 1, 2012 to December 31, 2012 are as follows:

	For the period from October 1, 2012 to December 31, 2012
Net sales	$ 167,112
Net loss	(4,489)

The following represents the pro forma consolidated net sales and net (loss) income as if Kildair had been included in the consolidated results of the Predecessor for the entire years ended December 31, 2012 and 2011:

	For the Years Ended December 31, 2012	2011
Net sales	$ 4,462,110	$ 4,430,526
Net (loss) income	(15,615)	29,419

These amounts have been calculated after applying the Predecessor s accounting policies and adjusting the results of Kildair to reflect the additional cost of products sold and depreciation and amortization that would have been charged assuming the fair value adjustments to inventory; property, plant and equipment; and intangible assets had been applied on January 1, 2012 and 2011, together with the consequential tax effects.

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Rensselaer Terminal

On September 30, 2011, the Predecessor purchased an oil terminal in Rensselaer, New York for $3.4 million. In addition, the Predecessor purchased approximately $4.4 million of inventory that was stored at the terminal. The fair value of the identifiable assets acquired was $13.9 million which exceeded the purchase price. As a result, the Predecessor reassessed the identification, recognition and measurement of the identifiable assets and concluded that the valuation procedures and resulting measures were appropriate. Accordingly, the Predecessor recognized a gain of $6.0 million associated with the acquisition, which is included in gain on acquisition of business in the Consolidated Statements of Operations. The terminal has 0.6 million barrels of storage capacity, with 0.3 million barrels currently in service, and primarily handles distillate oil products. The purchase of this facility provides enhanced dock facilities and augments the Predecessor s supply storage and petroleum marketing opportunities. The Predecessor believes that it was able to acquire the terminal for less than fair value of its assets because of the seller s strategic intent to exit a non-core business operation. This acquisition has been accounted for as a business combination.

The following table presents the allocation of the $7.8 million purchase price to the fair value of the acquired assets and resulting gain on acquisition of business:

Assets purchased:

Inventories	$ 4,445
Land and improvements	1,750
Plant and equipment	7,666
Total fair value of assets purchased	13,861
Gain on acquisition of business	(6,016)
Total purchase price	$ 7,845

4. Accumulated Other Comprehensive Loss, Net of Tax

Amounts included in accumulated other comprehensive loss, net of tax, consisted of the following:

	As of December 31,	
	2013	2012 Predecessor
Fair value of interest rate swaps, net of tax	$ (2,327)	$ (4,265)
Cumulative foreign currency translation loss adjustment		(1,308)
Accumulated other comprehensive loss, net of tax	$ (2,327)	$ (5,573)

The cumulative foreign currency translation loss adjustment as of December 31, 2012 includes a cumulative loss of $0.8 million related to the conversion of intercompany advances not anticipated to be settled in the foreseeable future**.**

5. Accounts Receivable, Net

	As of December 31, 2013	2012 Predecessor
Accounts receivable, trade	$ 240,011	$ 239,615
Less allowance for doubtful accounts	(1,607)	(2,556)
Net accounts receivable, trade	238,404	237,059
Accounts receivable, other	2,375	14,187
Accounts receivable, net	$ 240,779	$ 251,246

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Unbilled accounts receivable, included in accounts receivable, trade, at December 31, 2013 and 2012 were $44.6 million and $38.0 million, respectively. Unbilled receivables relate primarily to the delivery and sale of natural gas to customers in the current month. Such amounts generally are invoiced to the customer the following month when actual usage data becomes available.

A reconciliation of the beginning and ending amount of allowance for doubtful accounts is as follows:

	Balance at Beginning of Period	Charged to Expense	Charged (to) from Another Account	Deductions	Balance at End of Period
Balance, December 31, 2013:					
Deducted from asset accounts:					
Allowance for doubtful accounts	$ 2,556	$ 559	$ (740)	$ 768	$ 1,607
Allowance for notes receivable	2,847	328	740	400	3,515
Total	$ 5,403	$ 887	$	$ 1,168	$ 5,122
Predecessor Balance, December 31, 2012:					
Deducted from asset accounts:					
Allowance for doubtful accounts	$ 3,743	$ 591	$ (844)	$ 934	$ 2,556
Allowance for notes receivable	2,269		844	266	2,847
Total	$ 6,012	$ 591	$	$ 1,200	$ 5,403
Predecessor Balance, December 31, 2011:					
Deducted from asset accounts:					
Allowance for doubtful accounts	$ 2,693	$ 1,783	$ (342)	$ 391	$ 3,743
Allowance for notes receivable	2,191	(18)	342	246	2,269
Total	$ 4,884	$ 1,765	$	$ 637	$ 6,012

Notes receivable, net of allowance, are included in intangible assets and other, net in the Partnership s Consolidated Balance Sheets.

6. Inventories

	As of December 31, 2013	2012 Predecessor
Petroleum and related products	$ 344,403	$ 440,362

Asphalt		25,867
Coal	1,886	4,355
Natural gas	1,818	2,012
Inventories	$ 348,107	$ 472,596

Due to changing market conditions, the Partnership recorded a provision of $1.0 million, $6.3 million and $5.3 million as of December 31, 2013, 2012 and 2011, respectively, to write-down petroleum and natural gas inventory to its net realizable value. These charges are included in cost of products sold in the Consolidated Statements of Operations.

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7. Other Current Assets

	As of December 31, 2013	2012 Predecessor
Margin deposits with brokers	$ 15,410	$ 20,766
Prepaid petroleum products	5,428	4,473
Income tax receivable		3,853
Other	4,531	3,766
Other current assets	$ 25,369	$ 32,858

8. Property, Plant and Equipment, Net

	As of December 31, 2013	2012 Predecessor
Plant, machinery, furniture and fixtures	$ 181,999	$ 258,678
Buildings and leasehold improvements	12,288	13,632
Land and land improvements	21,417	21,929
Construction in progress	4,160	919
Property, plant and equipment, gross	219,864	295,158
Less: accumulated depreciation	(103,057)	(118,078)
Property, plant and equipment, net	$ 116,807	$ 177,080

Depreciation expense for the years ended December 31, 2013, 2012 and 2011 was $13.1 million, $10.7 million and $9.4 million, respectively.

Property, plant and equipment include the following amounts for capital leases:

	As of December 31, 2013	2012 Predecessor
Plant, machinery, furniture and fixtures	$ 12,627	$ 16,353
Buildings and leasehold improvements	4,281	4,281
Land and land improvements	251	251
Capital leased assets, gross	17,159	20,885
Less: accumulated amortization	(6,216)	(5,808)

Capital leased assets, net	$ 10,943	$ 15,077

Amortization expense on capital leased assets for the years ended December 31, 2013, 2012 and 2011 was $1.2 million, $0.9 million and $0.7 million, respectively.

9. Intangible and Other Assets, Net

	As of December 31,	
	2013	**2012**
		Predecessor
Deferred debt issuance costs	$ 13,211	$ 4,749
Intangible assets, net	1,577	14,588
Other	2,054	1,435
Intangible and other assets, net	$ 16,842	$ 20,772

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Deferred Debt Issuance Costs

The Partnership recorded amortization expense related to deferred debt issuance costs of $3.6 million, $3.1 million and $3.0 million during the years ended December 31, 2013, 2012 and 2011, respectively. The amortization of deferred debt issuance costs is recorded in interest expense in the accompanying Consolidated Statements of Operations

Intangible Assets

	As of December 31, 2013			
	Remaining Useful Life (Years)	Gross	Accumulated Amortization	Net
Customer relationships	5-12	$ 4,510	$ 2,933	$ 1,577
Intangible assets, net		$ 4,510	$ 2,933	$ 1,577

	Predecessor			
	As of December 31, 2012			
	Remaining Useful Life (Years)	Gross	Accumulated Amortization	Net
Customer relationships	7-15	$ 14,878	$ 3,947	$ 10,931
Other	5-10	3,931	274	3,657
Intangible assets, net		$ 18,809	$ 4,221	$ 14,588

The Partnership recorded amortization expense related to intangible assets of $2.4 million, $0.9 million and $0.4 million during the years ended December 31, 2013, 2012 and 2011, respectively. The amortization of intangible assets is recorded in depreciation and amortization expense in the accompanying Consolidated Statements of Operations.

During the years ended December 31, 2013 and 2012, the Predecessor acquired intangible assets of $0.5 million (consisting of customer relationships) and $13.9 million (consisting of $9.9 million of customer relationships and $4.0 million of other intangible assets), respectively. See Note 3 Acquisitions.

Amortization of intangible assets is calculated by the sum-of-the-years -digits method over the periods of expected benefit. The Partnership believes the sum-of-the-years -digits method of amortization properly reflects the timing of the recognition of the economic benefits realized from its intangible assets. The estimated future annual amortization expense of intangible assets for the years ending December 31, 2014, 2015, 2016, 2017 and 2018 is $0.4 million, $0.3 million, $0.3 million, $0.2 million and $0.1 million, respectively. As acquisitions and dispositions occur in the future, these amounts may vary.

10. Accrued Liabilities

	As of December 31,	
	2013	2012
		Predecessor
Customer prepayments and deposits	$ 9,082	$ 18,485
Accrued wages and benefits	7,295	8,061
Accrued product costs	2,243	7,573
Other	14,795	14,830
Accrued liabilities	$ 33,415	$ 48,949

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11. Debt

	As of December 31, 2013	2012 Predecessor
Current debt		
Credit agreements	$ 126,652	$ 254,060
Credit agreement Canadian subsidiary		35,183
Unsecured debt		25,000
Term debt Canadian subsidiary		2,833
Other		110
Current debt	126,652	317,186
Long-term debt		
Credit agreements	332,848	210,640
Term debt Canadian subsidiary		21,245
Other		122
Long-term debt	332,848	232,007
Total debt	$ 459,500	$ 549,193

Credit Agreement

The Partnership s revolving credit agreement (the Credit Agreement) was entered into on October 30, 2013 and has a maturity date of October 30, 2018. The Credit Agreement is secured by substantially all of the Partnership s assets and includes a $750.0 million working capital facility used to fund working capital and letters of credit and a $250.0 million acquisition facility. Borrowings under the Credit Agreement bear interest based on LIBOR, plus a specified margin, which is a function of the utilization of the Credit Agreement for the working capital facility and leverage ratio for the acquisition facility.

Prior to the IPO, the Predecessor s revolving credit agreement (the Predecessor Credit Agreement) was refinanced in May 2010 and has a maturity date of May 28, 2014. The Predecessor Credit Agreement was secured by substantially all of the Predecessor s assets and included a $625.0 million working capital facility used to fund working capital and letters of credit and a $175.0 million acquisition facility. Borrowings under the Predecessor Credit Agreement bore interest based on LIBOR, plus a specified margin, which is a function of the utilization of the Predecessor Credit Agreement.

As of December 31, 2013 and 2012, working capital facility borrowings were $351.6 million and $347.3 million, respectively, and outstanding letters of credit were $73.4 million and $92.0 million, respectively. The working capital facility is subject to borrowing base reporting and as of December 31, 2013 and 2012, had a borrowing base of $573.8 million and $529.3 million, respectively. As of December 31, 2013, excess availability under the working capital facility was $148.8 million.

As of December 31, 2013 and 2012, acquisition line borrowings were $107.9 million and $117.4 million, respectively. As of December 31, 2013, excess availability under the acquisition facility was $142.1 million.

The weighted average interest rate at December 31, 2013 and 2012 was 2.9% and 3.4%, respectively. The current portion of the credit agreement at December 31, 2013 and 2012 represents the amounts intended to be repaid during the following twelve month period.

The Credit Agreement contains certain restrictions and covenants among which are a minimum level of net working capital, fixed charge coverage and debt leverage ratios and limitations on the incurrence of

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indebtedness. The Credit Agreement limits the Partnership s ability to make distributions in the event of defaults as defined in the Credit Agreement. As of December 31, 2013, the Partnership is in compliance with these financial covenants.

Credit Agreement Canadian Subsidiary

The Predecessor s Canadian subsidiary utilizes a revolving credit agreement (the Canadian Credit Agreement) that has a maturity date of April 30, 2014, and is secured by substantially all of the Canadian subsidiary s assets. The Canadian Credit Agreement is used to fund working capital, letters of credit and letters of guarantee for an amount up to $107.0 million. Amounts can be borrowed in either U.S. or Canadian dollars. The loan bears interest at the prime rate plus 1.5% or the bank s cost of funds plus 3.0% and is renewable annually. The weighted average interest rate at December 31, 2012 was 4.5%.

As of December 31, 2012, borrowings under the Canadian Credit Agreement were $35.2 million. The Canadian Credit Agreement was subject to borrowing base reporting and as of December 31, 2012, had a borrowing base of $89.1 million. As of December 31, 2012, excess availability under the Canadian Credit Agreement was $53.9 million.

The terms of the Canadian Credit Agreement required the Canadian subsidiary to maintain specific levels of working capital, total liabilities to equity ratio, maintenance of a fixed charge coverage ratio, a limit on capital expenditures and a maximum net position for products consisting of heavy fuel oil and asphalt. Furthermore, the Canadian subsidiary was restricted in its ability to pay a dividend if such dividend would place them in default on any of the aforementioned covenants. The Predecessor entered into an undertaking with the Canadian Credit Agreement lenders whereby in the event of noncompliance with certain of these covenants the Predecessor would advance to the Canadian subsidiary up to $20.0 million in the form of subordinated notes to satisfy any such deficiency. As of December 31, 2012, the Predecessor advanced $10.4 million under this undertaking and, as a result, the Canadian subsidiary was in compliance with these financial covenants. This debt was contributed to an affiliate of Sprague Holdings in connection with the IPO.

Unsecured Debt

During September 2012, the Predecessor borrowed $25.0 million of unsecured debt bearing interest at LIBOR (0.2% at December 31, 2012) plus 4.0%. The unsecured debt is owed to a third-party financial institution and was originally scheduled to mature on September 24, 2013. On September 5, 2013, this note was extended to February 28, 2014. This debt was contributed to an affiliate of Sprague Holdings in connection with the IPO.

Term Debt Canadian Subsidiary

The Predecessor s Canadian subsidiary has a term loan outstanding that is payable in monthly installments of approximately $0.2 million, with a final maturity due in June 2014. Interest is payable at the Canadian prime rate (3.0% at December 31, 2012) plus 2.2%. This debt was contributed to an affiliate of Sprague Holdings in connection with the IPO.

12. Related Party Transactions

The Parent charged the Predecessor $1.1 million for the period January 1, 2013 to October 29, 2013 and $1.3 million for each of the years ended December 31, 2012 and 2011, respectively, for oversight and monitoring of the Predecessor. Such amounts are included in selling, general and administrative expenses in the Consolidated Statement of Operations. Intercompany activities are settled monthly and do not bear interest. There are no material intercompany accounts receivable or intercompany accounts payable balances outstanding with the Parent as of December 31, 2013 and 2012.

For the period from January 1, 2013 to October 30, 2013 and for the years ended December 31, 2012 and 2011, the Predecessor made cash distributions to the Parent of $40.0 million, $26.9 million and $26.0 million, respectively, as permitted by the Credit Agreement.

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In connection with the IPO, the Predecessor distributed to Sprague Holdings, or its affiliates, certain assets and liabilities, including among others, the equity investment in Kildair as well as accounts receivable of $130.2 million and cash of $10.0 million in an aggregate amount equal to the net proceeds of the IPO.

Through the General Partner, the Partnership participates in certain of the Parent s pension and other benefit plans (see Note 15) and the Predecessor also has a tax sharing agreement with the Parent (see Note 14).

During July 2013 the Predecessor received a capital contribution of $10.0 million from the Parent in connection with a business acquisition. (see Note 3 Acquisitions).

The General Partner charges the Partnership for the reimbursements of costs of employees and related employee benefits and other costs supporting our operations which amounted to $12.9 million for the period from October 30, 2013 through December 31, 2013. Prior to the IPO, these expenses were incurred directly by the Predecessor. Amounts due to the General Partner were $4.8 million as of December 31, 2013.

13. Other Liabilities

	As of December 31,	
	2013	2012 Predecessor
Port Authority terminal obligations	$ 9,012	$ 9,381
Postretirement benefit obligations	4,742	4,667
Environmental abatement obligation		2,643
Other	1,261	2,517
Other liabilities	$ 15,015	$ 19,208

The Port Authority terminal obligations represent long-term obligations of the Partnership to a third party that constructed dock facilities at the Partnership s Searsport, Maine terminal. These amounts will be repaid by future wharfage fees incurred by the Partnership for the use of these facilities. The short-term portion of these obligations of $0.6 million and $0.7 million at December 31, 2013 and 2012, respectively, is included in accrued liabilities and represents an estimate of the expected future wharfage fees for the ensuing year. The Partnership has exclusive rights to the use of the dock facilities through a license and operating agreement (License Agreement), which expires in 2033. The License Agreement provides the Partnership the option to purchase the dock facilities at any time at an amount equal to the remaining license fees due. The related dock facilities assets are treated as a capital lease and are included in property, plant and equipment.

Postretirement benefit obligations are comprised of actuarially determined postretirement healthcare, life insurance and other postretirement benefits. See Note 15.

The environmental abatement obligation is undiscounted and relates to an agreement that was assumed as part of the acquisition of an oil terminal in New Bedford, Massachusetts in 2005. Based on the agreement, the Predecessor is obligated to perform certain environmental abatement activities on or before December 28, 2017. This liability was distributed to Sprague Holdings in connection with the IPO.

14. Income Taxes

Prior to the completion of the IPO, the Predecessor prepared its income tax provision as if it operated as a stand-alone taxpayer for all periods presented in accordance with a pre-existing tax sharing agreement between the Predecessor and the Parent. With the completion of the IPO on October 30, 2013, the Partnership is now treated as a pass-through entity for federal income tax purposes. As a result, all income, expenses, gains, losses and tax credits generated flow through to its owners and, accordingly, do not result in a provision for federal income taxes and certain state income taxes.

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The Partnership is generally not subject to U.S. state and federal income tax, with the exception in certain domestic jurisdictions based on the Partnership s sourced taxable gross margin. The Partnership s taxable income or loss, which may vary substantially from the net income or net loss reported in the Consolidated Statements of Operations, is includable in the federal and state income tax returns of each unitholder.

The income tax (benefit) provision attributable to operations is summarized as follows:

	For the Years Ended December 31, 2013	2012 Predecessor	2011 Predecessor
Current			
U.S. federal income tax	$ 8,572	$ 2,272	$ 7,906
State and local income taxes	3,063	1,273	3,022
Foreign income taxes	895	(952)	1
Total current income tax provision	12,530	2,593	10,929
Deferred			
U.S. federal income tax	(3,420)	(3,576)	4,445
State and local income taxes	(2,358)	(890)	1,262
Foreign income taxes	(1,655)	(923)	
Total deferred income tax (benefit) provision	(7,433)	(5,389)	5,707
Total income tax provision (benefit)	$ 5,097	$ (2,796)	$ 16,636

U.S. and international components of (loss) income before income taxes and equity in net (loss) income of foreign affiliate were as follows:

	For the Years Ended December 31, 2013	2012 Predecessor	2011 Predecessor
U.S.	$ (15,772)	$ (8,389)	$ 42,586
Foreign	(6,631)	(6,229)	
Total (loss) income before income taxes and equity in net (loss) income of foreign affiliate	$ (22,403)	$ (14,618)	$ 42,586

Reconciliations of the statutory U.S. federal income tax to the effective income tax for operations are as follows:

	For the Years Ended December 31, 2013	2012	2011

		Predecessor	Predecessor
Statutory U.S. federal income tax at 35%	$ (7,841)	$ (5,116)	$ 14,905
Partnership losses not subject to tax	10,853		
State and local income taxes, net of federal tax	174	250	2,785
Foreign loss (earnings)	1,684	(1,305)	
Transaction costs	(55)	2,663	
Other, including non-recurring items	282	712	(1,054)
Total income tax provision (benefit)	$ 5,097	$ (2,796)	$ 16,636

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The components of the deferred tax assets (liabilities) are as follows:

	As of December 31, 2013	2012 Predecessor
Deferred tax assets (liabilities)		
Current		
Bad debts	$ 37	$ 966
Inventories	2,012	10,355
Compensation	138	1,832
Other	20	1,105
Current	2,207	14,258
Non-current		
Depreciation and amortization	(1,864)	(49,093)
Interest rate swaps	62	2,867
Other temporary differences, net	262	4,059
Valuation allowance		(369)
Non-current	(1,540)	(42,536)
Net deferred tax assets (liabilities)	$ 667	$ (28,278)

The Predecessor is not a separate taxable entity for U.S. federal and certain state income tax purposes and its results are included in the consolidated U.S. federal and certain state income tax returns of Lexa International Corporation, which is the sole stockholder of the Parent. Income tax provisions and benefits, related tax payments, and current and deferred tax balances have been prepared as if the Predecessor operated as a stand-alone taxpayer for all periods presented in accordance with the tax sharing agreement between the Predecessor and the Parent. Under the tax sharing agreement, the Predecessor is obligated to pay federal and certain state taxes to the Parent. In the event that the Parent does not have a consolidated liability for federal or certain state taxes, the Predecessor is not obligated to pay the Parent for such taxes and all such amounts are reflected as capital contributions. For the period from January 1, 2013 through October 29, 2013 and the years ended December 31, 2012 and 2011, the Predecessor received $8.8 million, $2.2 million and $7.9 million, respectively, of non-cash capital contributions from its Parent under the tax sharing agreement.

The Predecessor s and Partnership s policy is to accrue interest and penalties on uncertain tax positions as a component of income tax expense. During the years ended December 31, 2013, 2012 and 2011, the interest and penalties recognized by the Predecessor and Partnership were immaterial. The Partnership and its subsidiaries are subject to examination by the Internal Revenue Service and certain states for the period ended December 31, 2013.

15. Retirement Plans
Pension Plans

Through the General Partner, the Partnership participates in a noncontributory defined benefit pension plan, the Axel Johnson Inc. Retirement Plan (the Plan), sponsored by the Parent. Benefits under the Plan were frozen as of December 31, 2003, and are based on a participant s years of service and compensation through December 31, 2003. The Plan s assets are invested principally in equity and fixed income securities. The Parent s policy is to satisfy the minimum funding requirements of the Employee Retirement Income Security Act of 1974 (ERISA).

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Through the General Partner, the Partnership also participates in an unfunded pension plan, the Axel Johnson Inc. Retirement Restoration Plan, for employees whose benefits under the defined benefit pension plan were reduced due to limitations under federal tax laws. Benefits under this plan were frozen as of December 31, 2003.

Both the Plan and the Retirement Restoration Plan are administered by the Parent. The costs of these benefits are based on the Partnership s portion of the projected benefit obligations under these plans. Charges related to these employee benefit plans were $1.7 million, $1.2 million and $0.7 million during the years ended December 31, 2013, 2012 and 2011, respectively.

Eligible employees also receive a defined contribution retirement benefit generally equal to a defined percentage of their eligible compensation. This contribution by the Partnership to employee accounts in Axel Johnson Inc. s Thrift and Defined Contribution Plan is in addition to any Partnership match on 401(k) contributions that employees currently choose to make. The Partnership made total contributions to these plans of $3.1 million, $3.1 million and $3.0 million during the years ended December 31, 2013, 2012 and 2011, respectively.

Other Postretirement Benefits

The Parent and some of its subsidiaries, which include the Partnership, have a number of health care and life insurance benefit plans covering eligible employees who reach retirement age while working for the Parent. The plans are not funded. In general, employees hired after December 31, 1990, are not eligible for postretirement health care benefits. The Partnership has recorded postretirement expense of $0.4 million, $0.5 million, and $0.5 million during the years ended December 31, 2013, 2012 and 2011, respectively, related to these plans.

16. Segment Reporting

The Partnership is a wholesale and commercial distributor engaged in the purchase, storage, distribution and sale of refined products and natural gas, and also provides storage and handling services for a broad range of materials. The Partnership has four reporting operating segments that comprise the structure used by the chief operating decision makers (CEO and COO) to make key operating decisions and assess performance. These segments are refined products, natural gas, materials handling and other activities. Segment information includes Kildair since the acquisition date of October 1, 2012 and through October 30, 2013, the date Kildair was contributed to an affiliate of Sprague Holdings in connection with the IPO.

The Partnership s refined products segment purchases a variety of refined products, such as heating oil, diesel fuel, residual fuel oil, asphalt, kerosene, jet fuel and gasoline (primarily from refining companies, trading organizations and producers), and sells them to its customers. The Partnership has wholesale customers who resell the refined products they purchase from the Partnership and commercial customers who consume the refined products they purchase from the Partnership. The Partnership s wholesale customers consist of home heating oil retailers and diesel fuel and gasoline resellers. The Partnership s commercial customers include federal and state agencies, municipalities, regional transit authorities, large industrial companies, hospitals and educational institutions.

The Partnership s natural gas segment purchases, sells and distributes natural gas to commercial and industrial customers in the Northeast and Mid-Atlantic states. The Partnership purchases natural gas from natural gas producers and trading companies.

The Partnership s materials handling segment offloads, stores, and/or prepares for delivery a variety of customer-owned products, including asphalt, clay slurry, salt, gypsum, coal, petroleum coke, caustic soda, tallow, pulp and heavy equipment. These services are fee-based activities which are generally conducted under multi-year agreements.

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The Partnership s other activities include the purchase, sale and distribution of coal and commercial trucking activities unrelated to its refined products segment. Other activities are not reported separately as they represent less than 10% of consolidated net sales and adjusted gross margin.

The Partnership evaluates segment performance based on adjusted gross margin, which is gross margin decreased by total commodity derivative gains and losses included in net income (loss) and increased by realized commodity derivative gains and losses included in net income (loss), before allocations of corporate, terminal and trucking operating costs, depreciation, amortization, and interest. Based on the way the business is managed, it is not reasonably possible for the Partnership to allocate the components of operating costs and expenses among the operating segments. There were no significant intersegment sales for any of the years presented below.

Summarized financial information for the Partnership s reportable segments for the years ended December 31 is presented in the table below:

	For the Years Ended December 31,		
	2013	**2012 Predecessor**	**2011 Predecessor**
Net Sales:			
Refined products	$ 4,250,520	$ 3,757,859	$ 3,456,284
Natural gas	304,843	242,006	300,223
Materials handling	28,446	32,536	28,459
Other	16,925	11,506	12,461
Net sales	$ 4,600,734	$ 4,043,907	$ 3,797,427
Adjusted gross margin(1):			
Refined products	$ 110,172	$ 77,480	$ 97,031
Natural gas	40,373	26,844	22,710
Materials handling	28,430	32,320	28,371
Other	3,915	2,788	1,370
Adjusted gross margin	$ 182,890	$ 139,432	$ 149,482
Reconciliation to gross margin (2):			
Deduct: total commodity derivative gains (losses) included in net income (loss)(3)	(76,203)	(26,818)	(34,848)
Add: realized commodity derivative (gains) losses included in net income (loss)(3)	19,305	8,941	44,076
Gross margin	$ 125,992	$ 121,555	$ 158,710
Operating costs and expenses not allocated to operating segments:			
Operating expenses	51,839	47,054	42,414
Selling, general and administrative	53,580	46,449	46,292
Write-off of deferred offering costs		8,931	
Depreciation and amortization	15,452	11,665	10,140
Total operating costs and expenses	120,871	114,099	98,846

Operating income	5,121	7,456	59,864
Gain on acquisition of business		1,512	6,016
Other income (expense)	568	(160)	
Interest income	603	534	755
Interest expense	(28,695)	(23,960)	(24,049)
Income tax (provision) benefit	(5,097)	2,796	(16,636)
Equity in net (loss) income of foreign affiliate		(1,009)	3,622
Net (loss) income	$ (27,500)	$ (12,831)	$ 29,572

(1) Adjusted gross margin is a non-GAAP financial measure used by management and external users of the Partnership s consolidated financial statements to assess the Partnership s economic results of operations and its market value reporting to lenders.
(2) Reconciliation of adjusted gross margin to gross margin, a comparable GAAP measure.
(3) Both total commodity derivative gains and losses and realized commodity derivative gains and losses include amounts paid to enter into the settled contracts.

The Partnership had no single customer whose revenue was greater than 10% of total net sales for the years ended December 31, 2013, 2012 and 2011, respectively. The Partnership s foreign sales, primarily sales of refined products, asphalt and natural gas to its customers in Canada, were $230.9 million and $96.6 million for the years ended December 31, 2013 and 2012, respectively. The Partnership s foreign sales were not significant for the year ended December 31, 2011.

Segment Assets

Due to the comingled nature and uses of the Partnership s fixed assets, the Partnership does not track its fixed assets between its refined products and materials handling operating segments or its other activities. There are no significant fixed assets attributable to the natural gas reportable segment.

Changes in the carrying amount of goodwill by segment were as follows:

	As of December 31, 2011	Kildair Acquisition	Other (1)	As of December 31, 2012	Other (1)	Distribution(2)	As of December 31, 2013
Refined products	$ 29,242	$ 8,991	$ (88)	$ 38,145	(466)	(9,461)	$ 28,218
Natural gas	4,383			4,383			4,383
Materials handling	4,782	2,392	(24)	7,150	(124)	(2,244)	4,782
Other		1,228	(12)	1,216	(64)	(1,152)	
Total	$ 38,407	$ 12,611	$ (124)	$ 50,894	$ (654)	$ (12,857)	$ 37,383

(1) Reflects changes in the goodwill amounts resulting from foreign currency translation
(2) Reflects goodwill associated with assets that were contributed to an affiliate of Sprague Holdings in connection with the IPO.

Long-lived Assets

Long-lived assets (exclusive of intangible and other assets, net, and goodwill) classified by geographic location are as follows:

	As of December 31, 2013	2012

		Predecessor
United States	$ 116,807	$ 106,922
Canada		70,158
Total	$ 116,807	$ 177,080

17. Financial Instruments and Off-Balance Sheet Risk
Cash, Cash Equivalents, Accounts Receivable and Debt

As of December 31, 2013 and December 31, 2012, the carrying amounts of cash, cash equivalents and accounts receivable approximated fair value because of the short maturity of these instruments. As of December 31, 2013 and December 31, 2012, the carrying value of the Partnership s debt approximated fair value due to the variable interest nature of these instruments.

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Derivative Instruments

The following table presents all financial assets and financial liabilities of the Partnership measured at fair value on a recurring basis as of December 31, 2013 and December 31, 2012:

	As of December 31, 2013			
	Fair Value Measurement	Quoted Prices in Active Markets Level 1	Significant Other Observable Inputs Level 2	Significant Unobservable Inputs Level 3
Financial assets:				
Commodity exchange contracts	$ 165	$ 165	$	$
Commodity fixed forwards	64,729		64,729	
Commodity swaps and options	204		204	
Commodity derivatives	65,098	165	64,933	
Interest rate swaps				
Total	$ 65,098	$ 165	$ 64,933	$
Financial liabilities:				
Commodity fixed forwards	$ 128,368	$	$ 128,368	$
Commodity swaps and options	198		198	
Commodity derivatives	128,566		128,566	
Interest rate swaps	2,388		2,388	
Total	$ 130,954	$	$ 130,954	$

	Predecessor As of December 31, 2012			
	Fair Value Measurement	Quoted Prices in Active Markets Level 1	Significant Other Observable Inputs Level 2	Significant Unobservable Inputs Level 3
Financial assets:				
Commodity fixed forwards	$ 30,235	$	$ 30,235	$
Commodity swaps and options	597		597	
Commodity derivatives	30,832		30,832	
Currency swaps	20		20	
Total	$ 30,852	$	$ 30,852	$

Financial liabilities:				
Commodity exchange contracts	$ 9	$ 9	$	$
Commodity fixed forwards	42,247		42,247	
Commodity swaps and options	319		319	
Commodity derivatives	42,575	9	42,566	
Interest rate swaps	7,133		7,133	
Currency swaps	245		245	
Total	$ 49,953	$ 9	$ 49,944	$

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The Partnership enters into derivative contracts with counterparties, some of which are subject to master netting arrangements, which allow net settlements under certain conditions. The Partnership presents derivatives at gross fair values in the Consolidated Balance Sheets. Information related to these offsetting arrangements as of December 31, 2013 and December 31, 2012 is as follows:

	As of December 31, 2013					
				Gross Amount Not Offset in the Balance Sheet		
	Gross Amounts of Recognized Assets/Liabilities	Gross Amount Offset in the Balance Sheet	Amounts of Asset/Liabilities in Balance Sheet	Financial Instruments	Cash Collateral Posted	Net Amount
Commodity derivative assets	$ 65,098	$	$ 65,098	$ (5,506)	$ (4)	$ 59,588
Commodity derivative liabilities	(128,566)		(128,566)	5,506		(123,060)
Interest rate swap derivative liabilities	(2,388)		(2,388)			(2,388)

	Predecessor As of December 31, 2012					
				Gross Amount Not Offset in the Balance Sheet		
	Gross Amounts of Recognized Assets/Liabilities	Gross Amount Offset in the Balance Sheet	Amounts of Asset/Liabilities in Balance Sheet	Financial Instruments	Cash Collateral Posted	Net Amount
Commodity derivative assets	$ 30,832	$	$ 30,832	$ (3,163)	$ (94)	$ 27,575
Currency swap derivative assets	20		20			20
Commodity derivative liabilities	(42,575)		(42,575)	3,163		(39,412)
Interest rate swap derivative liabilities	(7,133)		(7,133)			(7,133)
Currency swap derivative liabilities	(245)		(245)			(245)

Commodity Derivatives

The following table presents total realized and unrealized (losses) and gains on derivative instruments utilized for commodity risk management purposes for the years ended December 31, 2013, 2012 and 2011. Such amounts are included in cost of products sold in the Consolidated Statements of Operations:

	2013	2012 Predecessor	2011 Predecessor
Refined products contracts	$ 504	$ (7,238)	$ (34,471)
Natural gas contracts	(76,707)	(19,580)	(377)
Total	$ (76,203)	$ (26,818)	$ (34,848)

Included in realized and unrealized (losses) gains on derivatives instruments above are realized and unrealized (losses) gains on discretionary trading activities as follows:

	2013	2012 Predecessor	2011 Predecessor
Refined products contracts	$ (1,232)	$ 2,317	$ 332
Natural gas contracts		8	(652)
Total	$ (1,232)	$ 2,325	$ (320)

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The following table presents the gross volume of commodity derivative instruments outstanding as of December 31, 2013 and 2012:

	As of December 31, 2013		Predecessor As of December 31, 2012	
	Refined Products (Barrels)	Natural Gas (MMBTUs)	Refined Products (Barrels)	Natural Gas (MMBTUs)
Long contracts	9,250	100,119	7,844	94,443
Short contracts	(11,538)	(74,265)	(11,829)	(70,432)

Interest Rate Derivatives

The Partnership has entered into interest rate swaps to manage its exposure to changes in interest rates on its Credit Agreements. The Partnership swaps the variable LIBOR interest rate payable under the Credit Agreements for fixed LIBOR interest rates. The Partnership s interest rates swaps hedge actual and forecasted LIBOR borrowings and have been designated as cash flow hedges. Counterparties to the Partnership s interest rate swaps are large multinational banks and the Partnership does not believe there is a material risk of counterparty non-performance. At December 31, 2013 the Partnership held six interest rate swap agreements with an aggregate notional value of $210.0 million. The cash flow hedges at December 31, 2013, expire at various dates through January 2015.

There was no material ineffectiveness determined for the cash flow hedges for the years ended December 31, 2013, 2012 and 2011. Any ineffectiveness is recorded as interest expense in the Consolidated Statements of Operations.

The Partnership records unrealized gains and losses on its interest rate swaps as a component of accumulated other comprehensive loss, net of tax, which is reclassified to earnings as interest expense when the payments are made. As of December 31, 2013, the amount of unrealized losses, net of tax, expected to be reclassified to earnings in 2014 was $2.4 million.

The following table presents the location of the gains and losses on derivative contracts designated as cash flow hedging instruments reported in the Consolidated Statements of Comprehensive (Loss) Income as other comprehensive loss (OCL) for the years ended December 31, 2013, 2012 and 2011:

	For the Year Ended December 31, 2013	
	Amount of Derivative Loss Recognized in OCL	Amount of Derivative Loss Reclassified From Accumulated OCL Into Income
Interest rate swaps	$ 376	$ 5,121

	Predecessor For the Year Ended December 31, 2012	
	Amount of Derivative Loss Recognized	Amount of Derivative Loss Reclassified From

	in OCL	Accumulated OCL Into Income
Interest rate swaps	$ 1,815	$ 4,144

	Predecessor For the Year Ended December 31, 2011	
	Amount of Derivative Loss Recognized in OCL	Amount of Derivative Loss Reclassified From Accumulated OCL Into Income
Interest rate swaps	$ 6,888	$ 4,142

Currency Derivatives

The Predecessor s Canadian subsidiary enters into forward currency contracts to manage the risk of currency rate fluctuations between its U.S. dollar denominated activity and the Canadian dollar, which is its functional currency. At December 31, 2012, the Predecessor s Canadian subsidiary has entered into a series of forward currency swaps that mature through February 2013. The contracts obligate the Canadian subsidiary to purchase approximately $52.0 million in U.S. dollars at exchange rates between 0.9797 and 0.9953. The U.S. to Canadian dollar exchange rate was 0.9921 at December 31, 2012.

18. Commitments and Contingencies

Capital Leases

The Partnership holds leases for office and warehouse space, dock facilities, transportation equipment and other equipment, several of which are recorded as capital leases. At December 31, 2013 and 2012, the Partnership had short-term capital lease obligations of $0.2 million and $0.7 million, respectively, and long-term capital lease obligations of $3.1 million and $5.7 million, respectively. These balances exclude the obligations related to its Searsport, Maine terminal. See Note 13. Capital lease repayments are due as follows:

	Amount
2014	$ 426
2015	426
2016	426
2017	426
2018	426
Thereafter	2,655
Total	4,785
Less amounts representing interest at rates between 6.3% and 7.4%	(1,525)
Present value of net minimum capital lease payments	$ 3,260

Operating Leases

The Partnership has leases for a refined products terminal, refined products storage, maritime charters, office and plant facilities, computer and other equipment for periods extending to 2029. Renewal options exist for a substantial portion of these leases. For operating leases, rental expense was $11.7 million, $10.8 million and $12.3 million for the years ended December 31, 2013, 2012 and 2011, respectively.

The following table summarizes the future annual payments for operating leases as of December 31, 2013:

	Amount
2014	$ 6,227

2015	5,604
2016	5,525
2017	2,654
2018	459
Thereafter	6,899
Total	$ 27,368

Legal, Environmental and Other Proceedings

The Partnership is involved in various lawsuits, other proceedings and environmental matters, all of which arose in the normal course of business. The Partnership believes, based upon its examination of currently available information, its experience to date, and advice from legal counsel, that the individual and aggregate liabilities resulting from the resolution of these contingent matters will not have a material adverse impact on the Partnership s consolidated results of operations, financial position or cash flows.

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19. Offering Costs Initial Public Offering

During 2012 and 2011, the Predecessor had accumulated certain costs related to efforts to complete an initial public offering of limited partnership units. During the year ended December 31, 2012, the Predecessor delayed the plan for this public offering and as a result, deferred offering costs of $8.9 million were charged against earnings. The total charge of $8.9 million included $6.5 million of offering costs previously deferred as of December 31, 2011, and $2.4 million of deferred offering costs incurred during the year ended December 31, 2012. The Predecessor retained no deferred offering costs on the accompanying Consolidated Balance Sheet as of December 31, 2012.

During 2013, the Partnership incurred offering costs of $12.7 million for the period January 1, 2013 through October 30, 2013 that were charged directly to equity upon completion of the IPO on October 30, 2013.

20. Equity-Based Compensation

During the quarter ended December 31, 2013, the General Partner issued a total of 6,666 restricted unit awards to certain directors under the 2013 LTIP. Recipients of restricted units have both distribution and voting rights on any unvested units. The fair value of each restricted unit on the grant date is equal to the market price of the Partnership s common unit on that date. The estimated fair value of the restricted units is amortized over the vesting period using the straight-line method. Total unrecognized compensation cost related to the nonvested restricted units totaled $0.1 million as of December 31, 2013, which is expected to be recognized over a period of approximately three years. The fair value of nonvested service restricted units outstanding was approximately $0.1 million as of December 31, 2013.

A summary of the Partnership s restricted unit award activity for the period from October 30, 2013 through December 31, 2013, is set forth below:

	Number of Restricted Common Units	Weighted-Average Grant Date Fair Value (in thousands)	
Nonvested at October 30, 2013		$	
Granted	6,666		116
Vested			
Nonvested at December 31, 2013	6,666	$	116

Unit-based compensation expense related to the Partnership is included in selling, general and administrative expenses in the Partnership s Consolidated Statement of Operations and was not significant for the period from October 30, 2013 (the completion of the IPO) through December 31, 2013.

21. Earnings Per Unit Calculation

Earnings per unit applicable to limited partners (including subordinated unitholders) is computed by dividing limited partners interest in net income (loss), after deducting any incentive distributions, by the weighted-average number of outstanding common and subordinated units. The Partnership s net income is allocated to the limited partners in accordance with their respective partnership percentages, after giving effect to priority income allocations for incentive distributions, if any, to Sprague Holdings, the holder of the IDRs, pursuant to the partnership agreement, which are declared and paid following the close of each quarter. Earnings (losses) per unit is only calculated for the Partnership after the IPO as no units were outstanding prior to October 30, 2013. Earnings in excess of distributions are allocated to the limited partners based on their respective ownership interests. Payments made to the Partnership s unitholders are determined in relation to actual distributions declared and are not based on the net income allocations used in the calculation of earnings per unit.

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In addition to the common and subordinated units, the Partnership has also identified the IDRs and unvested restricted units as participating securities and uses the two-class method when calculating the net income (loss) per unit applicable to limited partners, which is based on the weighted-average number of common units outstanding during the period. Diluted earnings per unit includes the effects of potentially dilutive units on the Partnership s common units, consisting of unvested restricted units. For the period from October 30, 2013 through December 31, 2013 basic and diluted earnings per unit applicable to common limited partners are the same because including the effect of unvested restricted units would have been anti-dilutive. Basic and diluted earnings (losses) per unit applicable to subordinated limited partners are the same because there are no potentially dilutive subordinated units outstanding.

The table below shows the weighted average common units outstanding used to compute net loss per common unit for the period from October 30, 2013 through December 31, 2013.

	Common
Weighted average limited partner common units outstanding:	
Units issued and outstanding	10,078,636
Less: units subject to vesting	(6,666)
Units used to determine net loss per common unit-basic	10,071,970

The following table presents the Partnership s basic earnings (loss) per common and subordinated unit for the year ended December 31, 2013:

	Common Units	Subordinated Units	Total
	(in $ thousands, except for per unit amounts)		
Net loss			$ (30,234)
Distributions declared	$ 2,846	$ 2,846	5,692
Assumed net loss from operations after distributions	(17,963)	(17,963)	(35,926)
Assumed net loss to be allocated	$ (15,117)	$ (15,117)	(30,234)
Basic and diluted loss per unit	$ 1.50	$ 1.50	$ 1.50

22. Quarterly Financial Data (Unaudited)

Unaudited quarterly financial data is as follows:

	For the Year Ended December 31, 2013				
	First	Second	Third	Fourth(1)	Total

Net sales	$ 1,544,953	$ 921,820	$ 940,275	$ 1,193,686	$ 4,600,734
Gross margin	66,792	32,117	25,701	1,382	125,992
Net income (loss)	14,334	(2,719)	(6,411)	(32,704)	(27,500)
Limited partners interest in net loss from October 30, 2013 to December 31, 2013				(30,234)	(30,234)
Net loss per limited partner unit(2):					
Common (basic and diluted)				$ (1.50)	$ (1.50)
Subordinated (basic and diluted)				$ (1.50)	$ (1.50)

	Predecessor For the Year Ended December 31, 2012				
	First	**Second**	**Third**	**Fourth(3)**	**Total**
Net sales	$ 1,268,200	$ 769,405	$ 703,694	$ 1,302,608	$ 4,043,907
Gross margin	38,421	31,408	13,204	38,522	121,555
Net income (loss)	950	6,316	(10,758)	(9,339)	(12,831)

(1) Includes the results of operations of the Predecessor through October 29, 2013 and the Partnership for the period October 30, 2013 through December 31, 2013.
(2) Net loss per unit is only calculated for the Partnership after the IPO as no units were outstanding prior to October 30, 2013.
(3) Net loss for the unaudited fourth quarter 2012 includes a gain of $1,512 related to an acquisition of a business (see Note 3 -Kildair) and a write-off of deferred costs of $8,931 (see Note 19).

23. Subsequent Event

Cash distributions

The partnership agreement sets forth the calculation to be used to determine the amount and priority of cash distributions that the common and subordinated unitholders will receive. On January 29, 2014, the Partnership declared a quarterly cash distribution totaling $5.7 million, or $0.2825 per unit. The quarterly cash distribution for the three months ended December 31, 2013 was calculated as the minimum quarterly cash distribution of $0.4125 prorated for the period beginning October 30, 2013, the date the Partnership commenced operations. This distribution was paid on February 14, 2014, to unitholders of record on February 10, 2014.

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EXHIBIT INDEX

Exhibits are incorporated by reference or are filed with this report as indicated below.

Exhibit No.	Description
3.1	First Amended and Restated Agreement of Limited Partnership of Sprague Resources LP (incorporated by reference to Exhibit 3.1 of Sprague Resources Partners LP s Current Report on Form 8-K filed November 5, 2013 (File No. 001-36137)).
3.2	First Amended and Restated Limited Liability Company Agreement of Sprague Resources GP LLC (incorporated by reference to Exhibit 3.2 of Sprague Resources Partners LP s Current Report on Form 8-K filed November 5, 2013 (File No. 001-36137)).
10.1	Credit Agreement among Sprague Operating Resources LLC, as borrower, the several lenders parties thereto, JPMorgan Chase Bank, N.A., as administrative agent, and the co-collateral agents, the co-syndication agents and the co-documentation agents party thereto (incorporated by reference to Exhibit 10.1 of Sprague Resources Partners LP s Current Report on Form 8-K filed November 5, 2013 (File No. 001-36137)).
10.2	Contribution, Conveyance and Assumption Agreement by and among Sprague Resources LP, Sprague Resources GP LLC, Axel Johnson Inc., Sprague International Properties LLC, Sprague Canadian Properties LLC, Sprague Resources Holdings LLC, Sprague Massachusetts Properties LLC and Sprague Operating Resources LLC (incorporated by reference to Exhibit 10.2 of Sprague Resources Partners LP s Current Report on Form 8-K filed November 5, 2013 (File No. 001-36137)).
10.3	Omnibus Agreement by and among Axel Johnson Inc., Sprague Resources Holdings LLC, Sprague Resources LP and Sprague Resources GP LLC (incorporated by reference to Exhibit 10.3 of Sprague Resources Partners LP s Current Report on Form 8-K filed November 5, 2013 (File No. 001-36137)).
10.4	Services Agreement by and among Sprague Resources GP LLC, Sprague Resources LP, Sprague Resources Holdings LLC and Sprague Energy Solutions Inc. (incorporated by reference to Exhibit 10.4 of Sprague Resources Partners LP s Current Report on Form 8-K filed November 5, 2013 (File No. 001-36137)).
10.5	Terminal Operating Agreement by and between Sprague Massachusetts Properties LLC and Sprague Operating Resources LLC (incorporated by reference to Exhibit 10.5 of Sprague Resources Partners LP s Current Report on Form 8-K filed November 5, 2013 (File No. 001-36137)).
10.6	Sprague Resources LP 2013 Long-Term Incentive Plan, effective as of October 28, 2013 (incorporated by reference to Exhibit 4.4 to Sprague Resources LP s Registration Statement on Form S-8, filed on October 25, 2013 (File No. 333-191923)).
10.7	Form of Phantom Unit Award Agreement (incorporated by reference to Exhibit 10.8 to Sprague Resources LP s Registration Statement on Form S-1, filed on September 24, 2013 (File No. 333-175826)).
10.8	Form of Restricted Unit Award Agreement (incorporated by reference to Exhibit 10.9 to Sprague Resources LP s Registration Statement on Form S-1, filed on September 24, 2013 (File No. 333-175826)).

10.9	Form of Unit Award Letter (incorporated by reference to Exhibit 10.10 to Sprague Resources LP s Registration Statement on Form S-1, filed on September 24, 2013 (File No. 333-175826)).
21.1*	Subsidiaries of the Registrant
23.1*	Consent of Ernst & Young LLP
31.1*	Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, Rule 13a-14(a) /15d-14(a), by Chief Executive Officer.
31.2*	Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, Rule 13a-14(a) /15d-14(a), by Chief Financial Officer.

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Exhibit No.	Description
32.1**	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Chief Executive Officer.
32.2**	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Chief Financial Officer.
101.INS***	XBRL Instance Document
101.SCH***	XBRL Taxonomy Extension Schema Document
101.CAL***	XBRL Taxonomy Extension Calculation
101.DEF***	XBRL Taxonomy Extension Definition
101.LAB***	XBRL Taxonomy Extension Label Linkbase
101.PRE***	XBRL Taxonomy Extension Presentation

Compensatory plan or arrangement.

* Filed herewith.

** Filed herewith. Pursuant to SEC Release No. 33-8212, this certification will be treated as accompanying this Annual Report on Form 10-K and not filed as part of such report for purposes of Section 18 of the Securities Exchange Act, as amended, or otherwise subject to the liability of Section 18 of the Securities Exchange Act, as amended, and this certification will not be deemed to be incorporated by reference into any filing under the Securities Exchange Act of 1933, as amended, except to the extent that the registrant specifically incorporates it by reference.

*** The documents formatted in XBRL (Extensible Business Reporting Language) and attached as Exhibit 101 to this report are deemed not filed as part of a registration statement or Annual Report on Form 10-K for purposes of Sections 11 or 12 of the Securities Act, are deemed not filed for purposes of Section 18 of the Exchange Act, and otherwise are not subject to liability under these sections.