Sprague Resources LP
Form 10-K
March 14, 2018
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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, 2017
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. ¨

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

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

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

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

The aggregate market value of common units held by non-affiliates of the registrant was approximately $283.3 million as of June 30, 2017 (the last business day of its most recently completed second fiscal quarter), based on the last sale price of such units as quoted on the New York Stock Exchange. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

The registrant had 22,727,284 common units outstanding as of March 6, 2018.

Documents Incorporated by Reference: None

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ANNUAL REPORT ON FORM 10-K
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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K (“Annual Report”) and any information incorporated by reference, contains statements that we believe are “forward-looking statements”. Forward looking statements are statements that express our belief, expectations, estimates, or intentions, as well as those statements we make that are not statements of historical fact. Forward-looking statements provide our current expectations and contain projections of results of operations, or financial condition, and/ or forecasts of future events. Words such as “may”, “assume”, “forecast”, “position”, “seek”, “predict “strategy”, “expect”, “intend”, “plan”, “estimate”, “anticipate”, “believe”, “project”, “budget”, “outlook”, “potential”, “will”, “ “continue”, and similar expressions are used to identify forward-looking statements. They can be affected by assumptions used or by known or unknown risks or uncertainties which could cause our actual results to differ materially from those contained in any forward-looking statement. Consequently, no forward-looking statements can be guaranteed. You are cautioned not to place undue reliance on any forward-looking statements.
Factors that could cause actual results to differ from those in the forward-looking statements include, but are not limited to: (i) changes in federal, state, local, and foreign laws or regulations including those that permit us to be treated as a partnership for federal income tax purposes, those that govern environmental protection and those that regulate the sale of our products to our customers; (ii) changes in the marketplace for our products or services resulting from events such as dramatic changes in commodity prices, increased competition, increased energy conservation, increased use of alternative fuels and new technologies, changes in local, domestic or international inventory levels, seasonality, changes in supply, weather and logistics disruptions, or general reductions in demand; (iii) security risks including terrorism and cyber-risk, (iv) adverse weather conditions, particularly warmer winter seasons and cooler summer seasons, climate change, environmental releases and natural disasters; (v) adverse local, regional, national, or international economic conditions, unfavorable capital market conditions and detrimental political developments such as the inability to move products between foreign locales and the United States; (vi) nonpayment or nonperformance by our customers or suppliers; (vii) shutdowns or interruptions at our terminals and storage assets or at the source points for the products we store or sell, disruptions in our labor force, as well as disruptions in our information technology systems; (viii) unanticipated capital expenditures in connection with the construction, repair, or replacement of our assets; (ix) our ability to integrate acquired assets with our existing assets and to realize anticipated cost savings and other efficiencies and benefits; and, (x) our ability to successfully complete our organic growth and/or acquisition projects and to realize the anticipated financial and operational benefits. These are not all of the important factors that could cause actual results to differ materially from those expressed in our forward-looking statements. Other known or unpredictable factors could also have material adverse effects on future results. Consequently, all of the forward-looking statements made in this Annual Report are qualified by these cautionary statements, and we cannot assure you that actual results or developments that we anticipate will be realized or, even if realized, will have the expected consequences to or effect on us or our business or operations. In light of these risks, uncertainties and assumptions, the forward-looking events discussed in this Annual Report may not occur. When considering these forward-looking statements, please note that we provide additional cautionary discussion of risks and uncertainties in Part I, Item 1A “Risk Factors”, in Part II, Item 7 “Management’s Discussion and Analysis of Financial Condition and Results of Operations”, and in Part II Item 7A “Quantitative and Qualitative Disclosures About Market Risk” of this Annual Report. In light of these risks, uncertainties and assumptions, the forward-looking events discussed in this Annual Report may not occur.

Forward-looking statements contained in this Annual Report 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 U.S. Securities and Exchange Commission (“SEC”). We undertake no obligation, and disclaim any obligation, to publicly update, review or revise any forward-looking statements to reflect events or circumstances after the date of such statements. All forward looking statements attributable to us or any person acting on our behalf are expressly qualified in their entirety by the cautionary statements contained or referred to in this Annual Report and our other existing and future periodic reports filed with the SEC.

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PART I

Item 1. Business

As used in this 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. References to our “General Partner” refer to Sprague Resources GP LLC. Our General Partner is a wholly-owned subsidiary of Axel Johnson Inc. Unless the context otherwise requires, references to “Axel Johnson” or the “Sponsor” refer to Axel Johnson Inc. and its controlled affiliates, collectively, other than Sprague Resources, its subsidiaries and its General Partner. In prior filings, our Sponsor was referred to as our "Parent". References to “Sprague Holdings” refer to Sprague Resources Holdings LLC, a wholly owned subsidiary of Axel Johnson and the owner of our General Partner.

Our Partnership

We are a Delaware limited partnership formed in June 2011 by Sprague Holdings and our General Partner. We engage in the purchase, storage, distribution and sale of refined products and natural gas, and provide storage and handling services for a broad range of materials. In October 2013, we became a publicly traded master limited partnership ("MLP") and our common units representing limited partner interests are listed on the New York Stock Exchange ("NYSE") under the ticker symbol “SRLP".

Our Predecessor was founded in 1870 as the Charles H. Sprague Company in Boston, Massachusetts; and, in 1905, the company opened the Penobscot Coal and Wharf Company, a tidewater terminal located in Searsport, Maine. By World War II, the company was operating eleven terminals and a fleet of two dozen vessels transporting coal and other products throughout the world. As fuel needs diversified in the United States, the company expanded its product offerings and invested in terminals, tankers, and product handing activities. In 1959, the company expanded its oil marketing activities via entry into the distillate oil market. In 1970, the company was sold to Royal Dutch Shell’s Asiatic Petroleum subsidiary; and, in 1972, Royal Dutch Shell sold the company to Axel Johnson Inc. a member of the Axel Johnson Group of Stockholm, Sweden.

We are one of the largest independent wholesale distributors of refined products in the Northeast United States based on aggregate terminal capacity. We own, operate and/or control a network of refined products and materials handling terminals strategically located throughout the Northeast United States and in Quebec, Canada that have a combined storage capacity of 14.7 million barrels for refined products and other liquid materials, as well as 2.0 million square feet of materials handling capacity. We have access to more than 50 third-party terminals in the Northeast United States 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. See “Segment Reporting” included under Note 16 to our Consolidated and Combined 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.

In our refined products segment we purchase 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 sell 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 directly. Our wholesale customers consist of more than 1,200 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, real estate management companies, hospitals, educational institutions and asphalt paving companies. In addition, as a result of the recent acquisition of Coen Energy, our customers include businesses engaged in the development of natural gas resources in Pennsylvania and surrounding states.

In our natural gas segment we purchase, sell and distribute natural gas to approximately 16,000 commercial and industrial customer locations across 13 states in the Northeast and Mid-Atlantic United States. We purchase the natural gas from natural gas producers and trading companies.

Our materials handling segment 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, crude oil, residual fuel, coal, petroleum coke, caustic soda, tallow, pulp and heavy equipment.

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Our other operations segment includes the marketing and distribution of coal conducted in our Portland, Maine terminal, commercial trucking activity conducted by our Canadian subsidiary and our heating equipment service business.

We take title to the products we sell in our refined products and natural gas segments. 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. We do not take title to any of the products in our materials handling segment.

As of December 31, 2017, our Sponsor, through its ownership of Sprague Holdings, owned 12,106,348 common units, representing a 54% limited partner interest in the Partnership. Sprague Holdings also owns our General Partner, which in turn owns a non-economic interest in the Partnership. Sprague Holdings currently holds all of our incentive distribution rights ("IDRs"), which entitle the holder to receive increasing percentages, up to a maximum of 50.0%, of the cash the Partnership distributes from distributable cash flow in excess of $0.474375 per unit per quarter. The maximum IDR distribution of 50.0% does not include any distributions that Sprague Holdings may receive on any limited partner units that it owns.

We furnish or file with the SEC 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. We make these documents available free of charge on our website as soon as reasonably practicable after we electronically file such material with, or furnish such material to, the SEC. Our internet address is www.spragueenergy.com. Information on our website is not incorporated into this Annual Report on Form 10-K or our other filings with the SEC and is not a part of them. The SEC maintains an Internet site (http://www.sec.gov) that contains reports, proxy and other information statements, and other information regarding issuers that file electronically with the SEC.

2017 Developments

Coen Energy Acquisition

On October 1, 2017, we purchased the membership interests of Coen Energy, LLC and Coen Transport, LLC as well as assets consisting of four bulk plants and underlying real estate (collectively, "Coen Energy"). Coen Energy, located in Washington, PA, provides energy products to commercial and residential customers located in Pennsylvania, Ohio and West Virginia. The Coen Energy business also provides fuel and delivery services to customers that are engaged in Marcellus and Utica shale drilling operations. The Coen Energy business is supported by four in-land bulk plants, two throughput locations, approximately 100 delivery vehicles and approximately 250 employees as of December 31, 2017.

Initial consideration paid was $35.3 million in cash, not including the purchase of inventory and other adjustments, which was financed with borrowings under our credit facility. Contingent consideration of up to $12 million is payable based on achieving certain economic performance measures during the three year period ending September 30, 2020.

Carbo Terminals Acquisition

On April 18, 2017, we acquired substantially all of the assets of Carbo Industries, Inc. and certain of its affiliates (together "Carbo") by purchasing Carbo's Inwood and Lawrence, New York refined product terminal assets and its associated wholesale distribution business. The fair value of the consideration totaled $72.0 million and consisted of $13.3 million in cash that was financed through borrowings under our credit facility, an obligation to pay $38.2 million over a ten year period (estimated net present value of $27.3 million) and 1,131,551 common units with a fair value at $31.4 million as of April 18, 2017. The Carbo terminals are primarily supplied by pipeline and have a combined gasoline, ethanol and distillate storage capacity of 174,000 barrels.

Capital Terminal Acquisition

On February 10, 2017, we acquired the East Providence, Rhode Island refined product terminal of Capital Terminal Company (the "Capital Terminal") for $22.0 million and was financed with borrowings under our credit facility. The terminal's combined distillate storage capacity of just over 1.0 million barrels had been leased by us since April 2014 and was previously included in our total storage capacity.

In conjunction with this acquisition, we undertook an expansion capital project to convert half of the terminal's storage capacity to gasoline and ethanol service to support a new ten year fee-for-service gasoline storage and handling agreement with a major East Coast gasoline marketer and another project to optimize distillate storage between this newly acquired terminal and our existing terminal facility in Providence to allow for expanded materials handling capability. Both projects were completed prior to December 31, 2017 at a total cost of approximately $16 million.

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Global Natural Gas & Power Acquisition

On February 1, 2017, we purchased the natural gas marketing and electricity brokering business of Global Partners LP ("Global Natural Gas & Power") for $17.3 million, not including the purchase of natural gas inventory, assumption of derivative liabilities and other adjustments. Consideration paid was $16.3 million and was financed with borrowings under our credit facility. The business serves approximately 4,000 commercial, industrial, municipal and institutional customer locations in the Northeast United States with approximately 8 billion cubic feet of natural gas and 1 billion kWh of electricity annually.

L.E. Belcher Terminal Acquisition

On February 1, 2017, we purchased the Springfield, Massachusetts refined product terminal assets of Leonard E. Belcher, Incorporated (“L.E. Belcher”) for $20.0 million in cash, not including the purchase of inventory and other adjustments. Consideration paid was $20.7 million and was financed with borrowings under our credit facility. The purchase consists of two pipeline-supplied distillate terminals and one distillate storage facility with a combined capacity of 283,000 barrels, as well as L.E. Belcher’s associated wholesale and commercial fuels businesses.

Amendment to Credit Agreement

On April 27, 2017, we entered into an agreement to amend the credit agreement to extend the maturity through April 27, 2021, reduce the U.S. dollar working capital facility from $1.0 billion to $950.0 million, reduce the multicurrency working capital facility from $120 million to $100 million, reduce interest rates under certain leverage ratio scenarios and make other modifications. See Part II, "Credit Agreement" located in the "Liquidity and Capital Resources" section of Item 7 "Management’s Discussion and Analysis of Financial Condition."

Conversion of Subordinated Units

Pursuant to the terms of our partnership agreement, upon payment of the cash distribution on February 14, 2017, and meeting certain distribution and performance tests, the subordination period for our subordinated units expired on February 16, 2017. At the expiration of the subordination period, all 10,071,970 subordinated units converted into common units on a one-for-one basis.

Business Strategies

Our primary business objective is to increase distributable cash flow per unit over time by executing the following strategies:

- Increase our business with our existing assets and customers. We will make investments in our existing asset base to handle additional products and provide new services to customers. We also intend to increase sales to existing customers by developing additional ways to address their need for certainty of supply, reduced commodity price risk and high quality customer service.
- Acquire additional terminals and marketing and distribution businesses that are accretive. 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 can leverage our existing investment in our logistics capabilities and customer service systems to further increase our cash flow.
- Limit our exposure to commodity price risk and volatility. We take title to the products we sell in our refined products and natural gas segments, while our materials handling business does not take title to products and is operated predominantly under fixed-fee, multi-year contracts. We will continue to manage our exposure to commodity prices and seek to protect our sales margins by maintaining a balanced position in our purchases and sales through the use of derivatives and forward contracts. Our hedging activities are bounded by specific limits established by the board of directors of our General Partner, which are monitored and reported to senior management on a daily basis by our risk group.
- Maintain our operational excellence. We intend to maintain our long history of safe, cost-effective operations and environmental stewardship by investing in the maintenance of our assets and providing training programs for our personnel. We will work diligently to meet or exceed applicable safety and environmental regulations and we will continue to enhance our safety programs as our business grows and operating conditions change.

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Refined Products

Overview

The products we sell in our refined products segment can be grouped into the following categories: distillates, gasoline and residual fuel oil and asphalt. In 2017, our refined products segment accounted for 86% of our total net sales. Of our total volume sold in our refined products segment in 2017, distillates accounted for 75%, gasoline accounted for 11% and residual fuel oil and asphalt accounted for 14%.

Distillates. We sell four kinds of distillates: heating oil (both unbranded and our proprietary premium HeatForce® heating oil brand), diesel fuel (both unbranded and our proprietary premium RoadForce ® diesel fuel brand), kerosene and jet fuel. In 2017, heating oil accounted for 58%, diesel fuel accounted for 38%, and other distillates accounted for 3% of the total volume of distillates we sold. We have the capability at several of our facilities to blend biodiesel with distillates in order to sell heating oil and diesel fuel with wide varieties of biodiesel content. In 2017, biofuel blends accounted for 11% of the distillate fuel volumes sold. Distillate volumes accounted for 75%, 73%, and 72% of our total refined products sales for the years ended December 31, 2017, 2016 and 2015, respectively.

Gasoline. We also sell unbranded gasoline. Gasoline volumes accounted for 11%, 13% and 13% of our total refined products sales for the years ended December 31, 2017, 2016 and 2015, respectively.

Residual Fuel Oil and Asphalt. We sell various sulfur grades of residual fuel oil, blended to meet customer requirements in our market areas with Kildair Service ULC ("Kildair"), our Canadian subsidiary, selling asphalt to Canadian customers. Residual fuel oil and asphalt volumes accounted for 14%, 14% and 15% of our total refined products sales for the years ended December 31, 2017, 2016 and 2015, respectively.

Customers, Contracts and Pricing

We sell heating oil, diesel fuel, kerosene, unbranded gasoline, jet fuel, residual fuel oil and asphalt 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 at facilities with which we have storage and throughput arrangements. In a FOB sale, the price of products sold includes the cost of delivering such product to the FOB location and any further shipping expenses are borne by the purchaser.

Heating oil sales are made to approximately 1,000 wholesale distributors and retailers through the Sprague RealTime® pricing platform, under rack agreements based upon our posted price, contracts with index-based pricing provisions, and fixed price forward contracts. Diesel fuel sales are made to approximately 660 wholesalers and transportation fuel distributors. We also sell unbranded gasoline at third-party locations, primarily to resellers. Residual fuel oil is sold to approximately 160 commercial and industrial accounts under rack agreements and contracts with index-based pricing provisions.

Our commercial customers include federal and state agencies, municipalities, regional transit authorities, large industrial companies, real estate management companies, natural gas resource development 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.

Public sector entities also purchase our heating oil, diesel fuel, unbranded gasoline and residual fuel oil through competitive bidding processes as well as distillate and residual fuel oil by truck to marine customers. We currently have contracts with the U.S. government as well as with numerous states, municipalities, agencies and educational institutions.

For the year ended December 31, 2017, no customer represented more than 10% of net sales for our refined products segment.

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Natural Gas

Overview

We sell natural gas and related delivery services to customers primarily located in the Northeast and Mid-Atlantic United States. For the year ended December 31, 2017, our natural gas segment accounted for 12% of our total net sales. 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 purchase instruments as well as financial and derivative instruments both over the counter and through exchanges such as the Intercontinental Exchange Inc. (“ICE”) and the New York Mercantile Exchange ("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 logistic opportunities, we enter into supply contracts, commitments 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.

Customers

Our natural gas customers operate in the industrial and commercial sectors in the Northeast United States, with the highest concentration in New England and New York. We acquired the natural gas marketing businesses of Metromedia Energy in 2014, Santa Buckley Energy, Inc. ("SBE") in 2016 and Global Natural Gas & Power in 2017, as part of our strategy to target smaller to mid-size commercial and industrial customers. This strategy has led to a significant increase in the number of customers served. 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 establishments). 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, 2017, 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 delivery location and then fix the price at a later date based on the prevailing market pricing. There are various other alternatives such as “capped” pricing (essentially setting a maximum) 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 limit the number of transactions that require a single price for all volumes delivered, with the pricing of the non-contractual volumes primarily based on prevailing market economics. For any transactions where the competitive dynamics do require a single price for all volumes delivered, we seek to manage the risk by, for instance, including appropriate increases in the cost build-up to reflect the higher hedging cost.

Materials Handling

Overview

Materials handling consists of 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 provide heavy lift services and other handling services to some of the same customers that we supply with refined products and natural gas. For the year ended December 31, 2017, our materials handling segment accounted for 2% of our total net sales.

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. 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.

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Major Types of Materials Handling and Services

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

Liquid. In a manner similar to our refined products operation our terminal network of marine docks, product pipelines and storage tanks are utilized to store and trans-load various other third party liquid products to and from ocean vessels, railcars and tanker trucks. Examples of liquid materials handled include crude oil, 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 in some cases transporting the product. Some products need to remain heated in storage to be able to flow at ambient temperatures. The operations of Kildair includes a materials handling contract involving trans-loading and storage of crude oil.

Bulk. Bulk materials are typically aggregate materials that are moved in large vessels configured with multiple holds that store products on ships with no packaging. Examples of bulk material include salt, petroleum coke, gypsum, and coal. These vessels are normally offloaded via cranes that can reside either 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: ocean shippers, multiple logistics firms, trucking firms and the materials supplier or consumer. Materials we handle normally fall into three 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 wood pulp for paper manufacture in Asia or Europe and tallow for biodiesel production in Europe. The third category of materials we handle are both crude oil and refined products sourced either in Canada, U.S. or internationally for a range of use in local refineries and or for further export to the U.S. or elsewhere.

For the year ended December 31, 2017, we had two customers who represented 26% of net sales for our materials handling segment, although no customer 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 (clay slurry) 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 typically 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, 2017, the weighted-average life of our materials handling contracts was nine years, with a weighted-average remaining term of four years, each based on adjusted gross margin as defined in 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”, attributable to these contracts. Historically, our customers have paid for terminal improvements for specialty handling systems such as a clay slurry screening plant, while we will pay for more generic infrastructure improvements such as storage pads.

For container and break bulk services, it is 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, subject to change depending on market conditions.

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Other Operations

Our other operations segment includes the marketing and distribution of coal that is conducted in our Portland, Maine terminal, commercial trucking activity in Kildair’s operations and the heating equipment service business. For the year ended December 31, 2017, our other operations segment accounted for less than 1% of our total net sales.

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 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 seek to use these transactions 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 commodity risk 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 and natural gas. 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 trade credit to limit counterparty risk and margin requirements.

Our risk management policies, and the specific limits therein, are intended to prevent unauthorized trading and to maintain substantial balance between purchases and sales or future delivery obligations. However, these steps may not detect and/or prevent all violations of such risk management policies, processes and procedures, particularly if deception or other intentional misconduct is involved.

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Storage and Distribution

Marine terminals and inland storage facilities play a key role in the distribution of product to our customers. 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 number 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.

The marine terminals and inland storage facilities from which we distribute product are supplied by ship, barge, truck, pipeline or rail. 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.

Our Terminals and Storage Facilities

We own, operate, and/or control a network of refined products and material handling terminals and storage facilities located in the Northeast United States from New York to Maine and in Quebec, Canada that have a combined storage capacity of 14.7 million barrels for refined products and other liquid materials, as well as 2.0 million square feet of materials handling capacity. Furthermore, we have access to approximately 50 third-party terminals in the Northeast United States through which we sell or distribute refined products pursuant to rack, exchange and throughput agreements.

We operate or control thirteen terminals that are capable of handling both liquid petroleum products and providing third-party materials handling services of which three terminals are dedicated to materials handling services. Inside warehouse capacity at our owned and/or operated terminals totaled 305,000 square feet with 1.7 million square feet of outside laydown space available.

For a more detailed description of our terminals and storage facilities, please read Item 2 - "Properties."

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Competition

We encounter varying degrees of competition in the marketing of our refined products based on product type and geographic location. In our Northeast United States 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, service 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 United States (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 sizable 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 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 stronger than for the second and third calendar quarters. For example, over the 36-month period ended December 31, 2017, we generated an average of 63% of our total heating oil and residual fuel oil net sales during the months of November through March.

Employees

As of December 31, 2017, our General Partner employed approximately 880 full-time employees who supported our operations, 60 of whom were covered by five collective bargaining agreements. Three of such collective bargaining agreements covering an aggregate of 47 employees are up for renewal in 2018. Our Canadian subsidiary had 101 employees as of December 31, 2017, 37 of whom were covered by one collective bargaining agreement that expires on March 18, 2021.

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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 $9.4 million per quarter, or $37.5 million per year, based on the number of common 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 dep ends 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 United States and eastern Canada;
- 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, and volatility of prices, of refined products and natural gas in both the spot and futures markets;
- Seasonal variation in temperature, which affects demand for natural gas and refined products such as 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 operating and general and administrative expenses, including reimbursements to our General Partner and certain of its affiliates for services provided to us;
- Fluctuations or changes in federal, state, local and foreign tax rates, including Canadian income and withholding tax rates;
- 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 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, 2017, we generated an average of 63% of our total heating oil and residual fuel oil net sales during the months of November through March in the Northeast United States and Canada. 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 unitholders. Any restrictions on our ability to borrow could restrict our ability to make quarterly distributions to 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 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 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;
- Unseasonably warm temperatures which would negatively impact demand for natural gas and refined products;
- High prices caused by an increase in the market price of refined products or natural gas, 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. For example, energy efficiency measures, including the installation of improved insulation and the development of more efficient furnaces and other heating devices and increased use of fuel efficient motor vehicles, have adversely affected demand for some of our products, particularly home heating oil and residual fuel oil; and,
- Conversion from consumption of heating oil or residual fuel oil to natural gas as such switching and conversions could reduce our sales of heating oil and residual fuel oil.

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 volumes stored, distributed and sold. As a result, we may experience declines in operating margin if our volumes decrease.

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Our business, financial condition, results of operations and ability to make quarterly distributions to 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 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 the primary source of financing for 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 increases as they and/or their customers may attempt to not perform under 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 unitholders as well as the value of our common units.

We are dependent upon the earnings and cash flow generated by operations in order to meet our debt service obligations and to allow us to make cash distributions to 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 business, which may, in turn, adversely affect our business, financial condition, results of operations and ability to make quarterly distributions to 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 the credit agreement may affect our ability to obtain future financing for and pursue attractive business opportunities and maintain flexibility in planning for, and reacting to, changes in business conditions. In addition, a failure to comply with the provisions of the 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."

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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 required debt service payments;
- 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 debt will depend upon, among other things, 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 operating results are not sufficient to maintain our indebtedness, we will be forced to take actions such as reducing distributions, reducing or delaying 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.

Changes in currency exchange rates could adversely affect our operating results.

Because we are a U.S. dollar reporting company and also conduct a portion of our Canadian operations in Canadian dollars, we are exposed to currency fluctuations and exchange rate risks that may adversely affect the U.S. dollar value of our earnings, cash flow and partners' capital under applicable accounting rules.

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

Weather conditions during winter have an impact on the demand for heating oil, residual fuel oil and natural gas. Because we supply distributors whose customers depend on heating oil, residual fuel oil and natural gas 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 adjusted gross margin realized on those sales and, consequently, our business, financial condition, results of operations and ability to make quarterly distributions to unitholders.

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 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 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 diesel fuel contracts to hedge heating oil. 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 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.

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

We are subject to risk of nonperformance by our customers, suppliers and counterparties. We purchase products from a variety of natural gas and refined product suppliers under term contracts and on the spot market. In times of extreme market demand or during market disruptions due to political events, natural disaster, logistical/delivery issues or otherwise, these suppliers may be unable 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 unitholders.

Additionally, 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 unitholders.

Furthermore, 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.

Some of our refined products and natural gas competitors have capital resources many times greater than ours and control greater supplies. Competitors able to supply customers with products and services at a lower price could adversely affect our business, financial condition, results of operations and ability to make quarterly distributions to 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 unitholders could be adversely affected. We may not be able to compete successfully with such companies.

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

In the ordinary course of business, we collect and store sensitive data, including intellectual property, our proprietary business information and that of our customers, suppliers and business partners, and personally identifiable information of our customers and employees, in data centers and on our networks. The secure maintenance of this information is critical to our operations. Despite our security measures, information technology and infrastructure may be vulnerable to attacks by hackers or breached due to employee error, malfeasance or other disruptions. Any such breach could compromise our networks and the information stored there could be accessed, publicly disclosed, lost or stolen. Any such access, disclosure or other loss of information could result in legal claims or proceedings, liability under laws that protect the privacy of personal information, regulatory penalties, disrupt operations and the services we provide to customers, damage our reputation, and cause a loss of confidence in our products and services, which could adversely affect business/operating margins, revenues and competitive position.

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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 accretive acquisitions that result in an increase in cash from operations generated per unit. If we are unable to make accretive acquisitions, either because we are (1) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts, (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 unitholders could be adversely affected.

Most of our contracts with refined products customers are for a single season or on a spot basis, while most of our contracts with 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 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 results of operations and distributable cash flow.

We rely primarily on sales generated from products distributed from the terminals we own, control or operate to which we have access. Furthermore, our operations are largely located in the Northeast United States and eastern Canada. 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, weather or decreases in demand for refined products or materials handling services, could have a significantly greater impact on our results of operations and distributable cash flow than if we operated in more diverse locations.

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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 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 could increase or 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 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. Failure to comply with environmental laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations.
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. If such third parties fail to comply with environmental laws, they could be shut down, requiring us to incur costs to use alternative facilities. Moreover, the failure to comply with these requirements can expose our operations to fines, penalties, permit revocation and injunctive relief, including limits or prohibitions on some or all of our operations.
The trend in environmental regulation has been to place more restrictions and limitations on activities that may affect the environment over time. As a result, there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts we

currently anticipate. We try to anticipate future regulatory requirements that might be imposed and plan accordingly to remain in compliance with changing environmental laws and regulations and minimize the costs of such compliance.

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We do not believe that compliance with federal, state or local environmental laws and regulations will have a material adverse effect on our financial position. We can provide no assurance, however, that future events, such as changes in existing laws (including changes in the interpretation of existing laws), the promulgation of new laws, or the development or discovery of new facts or conditions will not cause us to incur significant costs or have a material adverse effect on our financial position, results of operations or cash available for distribution to our unitholders.

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 as well as our transportation and logistics activities are 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 unitholders.

Increased regulation related to climate change and greenhouse gas (GHG) effects 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 unitholders.

Climate change, including the impact of global warming, creates physical and financial risk. Some scientists have concluded that increasing concentrations of GHG in the earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If any of those effects were to occur, they could have an adverse effect on our assets and operations. Additionally, we may become subject to legislation and regulation regarding climate change and compliance with any new rules could be difficult and costly. Concerned parties, such as legislators and regulators, shareholders and non-governmental organizations, as well as companies in many business sectors, are considering ways to reduce greenhouse gas (GHG) emissions. Foreign, federal, state and local regulatory and legislative bodies have proposed various legislative and regulatory measures relating to climate change, regulating GHG emissions and energy policies. If such legislation is enacted, we could incur increased energy, environmental and other costs and capital expenditures to comply with regulations and limitations. Due to the uncertainty in the regulatory and legislative processes, as well as the scope of such requirements and initiatives, we cannot currently determine the effect such legislation and regulation may have on our business, financial condition, results of operations and ability to make quarterly distributions to unitholders. Additionally, we could face increased costs related to defending and resolving legal claims and other litigation related to climate change and the alleged impact of our operations on climate change.

With regard to GHG emissions, on December 15, 2009, the Environmental Protection Agency, or the EPA, published its findings on emissions of carbon dioxide and other greenhouse gases and has begun to regulate greenhouse gas emissions pursuant to the Clean Air Act. Many states and regions have adopted GHG initiatives and it is possible that U.S. federal legislation could be adopted in the future to restrict GHG emissions. As a result, domestic efforts to curb GHG emissions continue to be led by the EPA GHG regulations and the efforts of states. For example, in May 2016 the EPA finalized rules that established emissions standards for methane and volatile organic compounds ("VOCs") from new and modified oil and natural gas production and natural gas processing and transmission facilities as part of the Obama Administration's efforts to reduce methane emissions from the oil and natural gas sector. However, in June 2017, the EPA published a proposed rule to stay certain portions of the 2016 standards for two years and reconsider the entirety of the 2016 standards. The EPA has not yet published a final rule issuing the stay, and, as a result,

substantial uncertainty exists with respect to implementation of the
methane rule. The EPA also took the first steps toward regulating existing oil and gas operations by issuing an Information Collection Request seeking a broad range of information, including the types of technologies that could be used to reduce emissions from existing sources and their associated costs; however; the EPA rescinded this request in March 2017. The EPA's new rules are not directly applicable to us, however, to the extent that our operations become subject to or affected by the EPA's GHG regulations, we may face increased capital and operating costs associated with new or expanded facilities.

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Kildair is subject to both Canadian federal and Quebec provincial environmental regulations that require the purchase of emission allowances, credits and/or compliance units needed to cover emissions attributable to the combustion of the fossil fuels they sell for consumption. To comply with these laws and regulations, Kildair must incur costs to purchase allowances, credits and compliance units that allow Kildair to continue operations at their current or increased levels. Increased costs may result in increased prices for Kildair's products or decreased profitability. Increased product price could result in a reduction of demand for Kildair's product and therefore reduce our revenues. Additional risks include the inability to acquire the required amount of emission allowances, credits or compliance units to offset emissions which would subject Kildair to various fines.

In August 2015, the EPA issued its final Clean Power Plan ("CPP") rules that establish carbon pollution standards for power plants. Though the CPP does not apply to our operations, it sets a national carbon pollution standard that is projected to cut emissions produced by United States power plants. Judicial challenges led the U.S. Supreme Court to grant a stay of the implementation of the CPP in 2016. By its terms, this stay will remain in effect throughout the pendency of the appeals process. The Supreme Court's stay applies only to the EPA's regulations for CO_2 emissions from existing power plants and will not affect the EPA's standards for new power plants. It is not yet clear how either the Circuit Court or the Supreme Court will rule on the legality of the CPP. Additionally, in October 2017 the EPA proposed to repeal the CPP, although the final outcome of this action and the pending litigation regarding the CPP is uncertain at this time. In connection with the proposed repeal, the EPA issued an Advance Notice of Proposed Rulemaking ("ANPRM") in December 2017 regarding emission guidelines to limit GHG emissions from existing electricity utility generating units. The ANPRM seeks comment regarding what the EPA should include in a potential new, existing-source regulation under the Clean Air Act of GHG emissions from electric utility generating units that it may propose. Were similar requirements to be imposed on the petroleum sector, it could add to our costs of operations and restrict the volumes we transport, which could have adverse effects on our business. 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.

Overall, there has been a trend towards increased regulation of GHGs and carbon pollution, both domestically and internationally, to limit emissions. Future efforts to limit emissions associated with transportation fuels and heating fuels could reduce the market for, or pricing of, our products, and thus adversely impact our business.

Additionally, activists concerned about the potential effects of climate change have recently directed their attention at sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult to secure funding for energy infrastructure projects, such as our terminal facilities.

Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to rise and will not peak until after 2040 and that oil and gas will continue to represent a substantial percentage of global energy use over that time.

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 Bronx, Lawrence, Mt. Vernon, and Albany, New York; Providence, Rhode Island; and Sorel-Tracy Quebec, Canada. 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.

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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 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 unitholders.

Risks Inherent in an Investment in Us

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

We expect that we will distribute in increasing amounts 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 a significant portion 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 the partnership agreement or 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 adversely impact the cash that we have available to distribute to 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.

As of March 6, 2018, Axel Johnson, through its ownership of Sprague Holdings, indirectly owns a 54% 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.
- Neither our partnership agreement nor any other agreement requires Axel Johnson or Sprague Holdings to pursue a business strategy that favors us. Axel Johnson’s directors and officers have a fiduciary duty to make decisions in the best interests of the stockholder’s of Axel Johnson.
- Some officers of our General Partner who provide services to us devote time to affiliates of our General Partner.

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- 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 and to the holders of the incentive distribution rights.
- 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 available to the holders of our common units and to the holders of the incentive distribution rights. 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, 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, including incentive distributions.
- 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 the incentive distributions.
- 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 unitholders. This election may result in lower distributions to common unitholders in certain situations.

Under the terms of our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, does not apply to our General Partner or any of its affiliates, including 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.

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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 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 under 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 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

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- 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, 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. 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 is required to remove our General Partner. As of March 6, 2018, Sprague Holdings and its affiliates owned 54% of our common units.

Furthermore, unitholders' voting rights are further restricted by the partnership agreement provision providing that any units held by a person that owns 20% 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.

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

Our General Partner may transfer its General Partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of the unitholders. Furthermore, 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 the partnership agreement nor the 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;
- 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 6, 2018, Sprague Holdings and its affiliates held 12,106,348 common units. We have agreed to provide Sprague Holdings with certain registration rights (which may facilitate the sale by Sprague Holdings of its common 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 on 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 our 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.

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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 our 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 incentive distributions.

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 6, 2018, Sprague Holdings and its affiliates owned 54% 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.

All of our outstanding subordinated units converted into common units on a one-for-one basis on February 16, 2017, 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.

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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 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 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 New York Stock Exchange (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 U.S. federal income tax purposes, or we become subject to entity level taxation for state tax purposes, our cash available for distribution would be substantially reduced. 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 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 U.S. federal income tax purposes unless it satisfies a "qualifying income" requirement. Based upon our current operations, we believe we satisfy the qualifying income requirement. However, no ruling has been or will be requested regarding our treatment as a partnership for U.S. federal income tax purposes. Failing to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for U.S. federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for U.S. federal income tax purposes, we would pay U.S. federal income tax on our taxable income at the corporate tax rate, and would likely pay additional state income tax at varying rates. Distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses or deductions would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, our cash available for distributions to our unitholders 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.

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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. From
time to time, members of Congress have proposed and considered substantive changes to the existing U.S. federal income tax laws that would affect publicly traded partnerships. Although there is no current legislative proposal, a prior legislative proposal would have eliminated the qualifying income exception to the treatment of all publicly traded partnerships as corporations upon which we rely for our treatment as a partnership for U.S. federal income tax purposes.
With regard to qualifying income, on January 24, 2017, final regulations concerning which activities give rise to qualifying income within the meaning of Section 7704 of the Code (the "Final Regulations") were published in the Federal Register. The Final Regulations are effective as of January 19, 2017, and apply to taxable years beginning on or after January 19, 2017. We do not believe the Final Regulations affect our ability to be treated as a partnership for U.S. federal income tax purposes.
Any modification to the U.S. federal income tax laws or other applicable tax laws may be applied retroactively and could make it more difficult or impossible for us to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. We are unable to predict whether any of these changes or other proposals will ultimately be enacted. Any similar or future legislative changes could negatively impact the value of an investment in our common units. You are urged to consult with your own tax advisor with respect to the status of regulatory or administrative
developments and proposals and their potential effect on your investment in our common units.
In addition to U.S. federal income tax, we are currently subject to entity level taxes and fees in a number of states and such taxes and fees reduce our distributable cash flow. Changes in current state and local laws may subject us to additional entity-level taxation by individual states and local governments. Additionally, unitholders may be subject to other state and local taxes that are imposed by various jurisdictions in which the unitholder resides or in which we conduct business or own property.
Our partnership agreement provides that if a law is enacted, or existing law is modified or interpreted in a manner, that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for U.S. federal, state, local or non-U.S. income tax purposes, the minimum quarterly distribution amount and the target distribution amounts may be adjusted to reflect the impact of that law on us.
Notwithstanding our treatment for U.S. federal income tax purposes, we are subject to certain non-U.S. taxes. If a taxing authority were to successfully assert that we have more tax liability than we anticipate or legislation were enacted that increased the taxes to which we are subject, our distributable cash flow would be further reduced.
A material amount of our business operations and subsidiaries are subject to income, withholding and other taxes in the non-U.S. jurisdictions in which they are organized or from which they receive income, reducing the amount of our distributable cash flow. In computing our tax obligation in these non-U.S. jurisdictions, we are required to take various tax accounting and reporting positions on matters that are not entirely free from doubt and for which we have not received rulings from the governing tax authorities, such as whether withholding taxes will be reduced by the application of certain tax treaties. Upon review of these positions, the applicable authorities may not agree with our positions. A successful challenge by a tax authority could result in additional tax being imposed on us. In addition, changes in our operations or ownership could result in higher than anticipated tax being imposed in jurisdictions in which we are organized or from which we receive income. Any such increases in tax imposed on us would further reduce our distributable cash flow. Although these taxes may be properly characterized as foreign income taxes, unitholders may not be able to credit them against their liability for U.S. federal income taxes on their share of our earnings.
Our unitholders are required to pay taxes on their share of our income even if they do not receive any cash distributions from us.
Our unitholders are required to pay any U.S. 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. For example, if we sell assets and use the proceeds to repay existing debt or fund capital expenditures, unitholders may be allocated taxable income

and gain resulting from the sale and our cash available for distribution would not increase. Similarly, taking advantage of opportunities to reduce our existing debt, such as debt exchanges, debt repurchases, or modifications of our existing debt could result in “cancellation of indebtedness income” being allocated to our unitholders as taxable income without any increase in our cash available for distribution. 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.

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Tax gain or loss on the disposition of our common units could be more or less than our unitholders expect.
If a unitholder sells common units, such unitholder will recognize gain or loss equal to the difference between the amount realized and the unitholder's tax basis in those units. Because distributions in excess of the unitholder's allocable share of our net taxable income decrease its tax basis in its common units, the amount, if any, of such prior excess distributions with respect to the units being sold will, in effect, become taxable income to the unitholder if it sells such units at a price greater than its tax basis in those units, even if the price received is less than the unitholder's original cost. In addition, because the amount realized includes a unitholder's share of our nonrecourse liabilities, if a unitholder sells units, such unitholder may incur a tax liability in excess of the amount of cash received from the sale. A substantial portion of the amount realized from the sale of your units, whether or not representing gain, may be taxed as ordinary income to you due to potential recapture items, including depreciation recapture. Thus, you may recognize both ordinary income and capital loss from the sale of your units if the amount realized on a sale of your units is less than your adjusted basis in the units. Net capital loss may only offset capital gains and, in the case of individuals, up to $3,000 of ordinary income per year. In the taxable period in which you sell your units, you may recognize ordinary income from our allocations of income and gain to you prior to the sale and from recapture items that generally cannot be offset by any capital loss recognized upon the sale of units.
Unitholders may be subject to limitation on their ability to deduct interest expense incurred by us.

In general, we are entitled to a deduction for interest paid or accrued on indebtedness properly allocable to our trade or business during our taxable year. However, under the Tax Cuts and Jobs Act, for taxable years beginning after December 31, 2017, our deduction for "business interest" is limited to the sum of our business interest income and 30% of our "adjusted taxable income." For the purposes of this limitation, our adjusted taxable income is computed without regard to any business interest expense or business interest income, and in the case of taxable years beginning before January 1, 2022, any deduction allowable for depreciation, amortization, or depletion.
Tax-exempt entities face unique tax issues from owning common units that may result in adverse tax consequences to them.
Investment in our common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts ("IRAs"), raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from U.S. federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Further, with respect to taxable years beginning after December 31, 2017, a tax-exempt entity with more than one unrelated trade or business (including by attribution from investment in a partnership such as ours that is engaged in one or more unrelated trades or businesses) is required to compute the unrelated business taxable income of such tax-exempt entity separately with respect to each such trade or business (including for purposes of determining any net operating loss deduction). As a result, for years beginning after December 31, 2017, it may not be possible for tax-exempt entities to utilize losses from an investment in our partnership to offset unrelated business taxable income from another unrelated trade or business and vice versa. If you are a tax exempt entity, you should consult your tax advisor before investing in our common units.

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

Non-U.S. unitholders are generally taxed and subject to income tax filing requirements by the United States on income effectively connected with a U.S. trade or business ("effectively connected income"). Income allocated to our unitholders and any gain from the sale of our units will generally be considered to be "effectively connected" with a U.S. trade or business. As a result, distributions to a non-U.S. unitholder will be subject to withholding at the highest applicable effective tax rate and a non-U.S. unitholder who sells or otherwise disposes of a unit will also be subject to U.S. federal income tax on the gain realized from the sale or disposition of that unit.

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

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If a tax authority contests the tax positions we take, the market for our common units may be adversely affected and the cost of any such contest would reduce our distributable cash flow.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for U.S. federal income tax purposes. Tax authorities 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 a tax authority may materially and adversely affect the market for our common units and the price at which they trade. Our costs of any contest with a tax authority will be borne indirectly by our unitholders and our General Partner because the costs will reduce our distributable cash flow.

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

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

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 have adopted certain methods for allocating depreciation and amortization that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to the use of these methods could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from any 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 generally 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 (the

"Allocation Date"), instead of on the basis of the date a particular common unit is transferred. Similarly, we generally allocate certain deductions for depreciation of capital additions, gain or loss realized on a sale or other disposition of our assets and, in the discretion of our General Partner, any other extraordinary item of income, gain, loss or deduction based upon ownership on the Allocation Date. Treasury Regulations allow a similar monthly simplifying convention, but such regulations do not specifically authorize all aspects of our proration method. If the IRS were to challenge our proration method, we may be required to change the allocation of items of income, gain, loss, and deduction among our unitholders.

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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 recognize gain or loss from the disposition.

Because there are no specific rules governing the U.S. federal income tax consequences of loaning a partnership interest, a unitholder whose common units are the subject of a securities loan to the short seller 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 are urged to consult a tax advisor to determine whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their common units.

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

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

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

Our unitholders will likely be subject to state and local taxes and income tax return filing requirements in jurisdictions where they do not live as a result of investing in our common units.

In addition to U.S. federal income taxes, unitholders will likely be subject to other taxes, including foreign, state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if they do not live in any of those jurisdictions. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, unitholders may be subject to penalties for failure to comply with those requirements. We conduct business and own property in numerous states, in the United 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 U.S. states or non-U.S. countries that impose a personal income tax in the future. 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 owned, operated and/or controlled terminals as of December 31, 2017.

	Liquids Storage Terminals	Number of Storage Tanks	Storage Tank Capacity (Bbls)	Principal Products and Materials
**	Sorel-Tracy Quebec, Canada	27	3,282,600	refined products; asphalt, crude oil
**	Searsport, ME	17	1,140,700	refined products; caustic soda; asphalt
**	South Portland, ME	25	1,021,000	refined products; asphalt; clay slurry
*	Bridgeport, CT	11	1,120,600	refined products
*	Albany, NY	9	1,103,600	refined products
*	East Providence, RI (1)	9	970,400	refined products
**	Newington, NH: River Road	29	1,157,300	refined products; asphalt; tallow
**	Bronx, NY	18	907,500	refined products; asphalt
**	Newington, NH: Avery Lane	12	722,000	refined products, asphalt
*	New Haven, CT (2)	15	683,300	refined products
*	Quincy, MA	9	657,000	refined products
**	Providence, RI	4	484,000	refined products; asphalt
***	Everett, MA	4	317,600	asphalt
*	Quincy, MA: TRT (3)	4	304,200	refined products
*	Springfield, MA	10	268,200	refined products
***	Oswego, NY	3	209,800	asphalt
*	Lawrence, NY and Inwood NY	10	174,000	refined products
*	New Bedford, MA (4)	2	85,900	refined products
*	Mount Vernon, NY	7	72,100	refined products
*	Stamford, CT	3	46,600	refined products
*	Washington, PA area - four locations	20	9,100	refined products
	Total	248	14,737,500	

	Dry Storage Terminals	Number of Storage Pads and Warehouses	Storage Capacity (Square Feet)	Principal Products and Materials
**	Newington, NH: River Road	3 pads	390,000	salt; gypsum
**	Searsport, ME	2 warehouses;	90,000	break bulk; salt; petroleum coke;
		15 pads	872,000	heavy lift
***	Portland, ME (5)	7 warehouses;	215,000	break bulk; dry bulk; coal;
		3 pads	95,000	salt
**	South Portland, ME	3 pads	230,000	salt; coal
**	Providence, RI	1 pad	75,000	salt
		9 warehouses;		
	Total	25 pads	1,967,000	

*Refined Product activities; **Refined Products and Materials Handling activities; *** Materials Handling activities

(1) These tanks were previously controlled by us via a petroleum storage services agreement and acquired by us during 2017.
(2) These tanks are controlled via a storage and thruput agreement with an initial term through July 2, 2019.
(3) Operating assets and real estate are leased from an unaffiliated third party through April 30, 2025.
(4) Operating assets and real estate are leased from a subsidiary of Sprague Holdings through October 30, 2018.
(5) One storage warehouse is leased from an unaffiliated third party and the balance of the property is owned by us.

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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 Registrant's 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. As of March 6, 2018, Sprague Holdings owned 12,106,348 common units, which represents 54% of the limited partner interest in us. As of March 6, 2018, the closing market price for our common units was $23.15 per unit. We have gathered tax information for our known unitholders and from brokers/nominees and, based on the information collected, we have estimated that the number of our beneficial common unitholders at December 31, 2017 was 7,231.

The following table sets forth the range of the high and low prices of our common units and cash distributions to common unitholders on a quarterly basis for the two years ending December 31, 2017:

	Sales Price per Common Unit				
Quarter Ended	High	Low	Distribution per Unit	Record Date	Distribution Date
2016:					
March 31, 2016	$ 20.54	$ 15.85	$ 0.5325	May 9, 2016	May 13, 2016
June 30, 2016	$ 24.91	$ 18.34	$ 0.5475	August 8, 2016	August 12, 2016
September 30, 2016	$ 25.61	$ 23.42	$ 0.5625	November 8, 2016	November 14, 2016
December 31, 2016	$ 28.10	$ 22.55	$ 0.5775	February 8, 2017	February 14, 2017
2017:					
March 31, 2017	$ 28.90	$ 25.25	$ 0.5925	May 8, 2017	May 15, 2017
June 30, 2017	$ 30.10	$ 25.15	$ 0.6075	August 7, 2017	August 11, 2017
September 30, 2017	$ 28.10	$ 24.25	$ 0.6225	November 6, 2017	November 13, 2017
December 31, 2017	$ 26.65	$ 23.20	$ 0.6375	February 6, 2018	February 12, 2018

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 notwithstanding our stated cash distribution policy.

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- Our General Partner has 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

Conversion of Subordinated Units

Pursuant to the terms of our partnership agreement, upon payment of the cash distribution on February 14, 2017, and meeting certain distribution and performance tests, the subordination period for our subordinated units expired on February 16, 2017. At the expiration of the subordination period, all 10,071,970 subordinated units converted into common units on a one-for-one basis.

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 distributable cash flow in excess of $0.61875 per unit per quarter. The maximum IDR distribution of 50.0% does not include any distributions that our sponsor may receive on any limited partner units that it owns.

Recent Sales of Unregistered Securities

On April 18, 2017, in connection with the closing of the acquisition of Carbo, pursuant to the terms of a unit purchase agreement, dated March 13, 2017, between Sprague Resources LP and Carbo Industries, Inc. (the “Unit Purchase Agreement”), we issued 1,131,551 common units to Carbo Industries, Inc. The common units were issued pursuant to the exemption set forth in Section 4(a)(2) of the Securities Act of 1933, as amended, and/or Rule 506 of Regulation D promulgated thereunder, based upon the investment representations made by Carbo Industries in the Unit Purchase Agreement, including its representation that it is an “accredited investor” within the meaning of Rule 501(a) of Regulation D and will be acquiring the common units for its own account and not with a view toward any distribution in violation of any securities laws.

Please read Item 1, "Business-Recent Developments-Conversion of Subordinated Units" for information on the conversion of our subordinated units into common units.

Issuer Purchases of Equity Securities

None.

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Item 6. Selected Financial Data

The following table presents selected historical financial and operating data of the Partnership and our Predecessor, Sprague Operating Resources LLC, as of the dates and for the periods indicated. The selected historical financial data as of and for the years ended December 31, 2017, 2016, 2015 and 2014 are derived from the Partnership's 2017, 2016, 2015 and 2014 audited Consolidated Financial Statements. The selected historical financial data as of 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, and is derived from the Partnership's 2013 audited Consolidated and Combined Financial Statements.

The following table presents the non-GAAP financial measure of adjusted EBITDA, which we use in our business as an important supplemental measure of our performance. We define and explain this measure in 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" and reconcile EBITDA and Adjusted EBITDA to net income (loss), their most directly comparable financial measure calculated and presented in accordance with GAAP.

	Years Ended December 31,				
	2017	2016	2015	2014	2013
	(in thousands, except unit data and operating data)				
Statements of Operations Data:					
Net sales	$2,854,996	$2,389,998	$3,481,914	$5,069,762	$4,683,349
Cost of products sold (exclusive of depreciation and amortization)	2,602,788	2,179,089	3,188,924	4,755,031	4,554,188
Operating expenses	72,284	65,882	71,468	62,993	53,273
Selling, general and administrative	87,582	84,257	94,403	76,420	55,210
Depreciation and amortization	28,125	21,237	20,342	17,625	16,515
Total operating costs and expenses	2,790,779	2,350,465	3,375,137	4,912,069	4,679,186
Operating income	64,217	39,533	106,777	157,693	4,163
Other income (expense)	108	(114)	298	(288)	568
Interest income	339	388	456	569	604
Interest expense	(31,345)	(27,533)	(27,367)	(29,651)	(30,914)
Income (loss) before income taxes	33,319	12,274	80,164	128,323	(25,579)
Income tax provision (1)	(3,822)	(2,108)	(1,816)	(5,509)	(4,259)
Net income (loss)	$29,497	$10,166	$78,348	$122,814	$(29,838)
Add/(deduct):					
Predecessor income through October 29, 2013	—	—	—	—	(2,734)
(Income) loss attributable to Kildair from October 29, 2013 through December 8, 2014	—	—	—	(4,080)	2,338
Incentive distributions declared	(3,993)	(1,742)	(321)	—	—
Limited partners' interest in net income (loss) (2)	$25,504	$8,424	$78,027	$118,734	$(30,234)
Net income per limited partner unit:					
Common—basic	$1.15	$0.40	$3.71	$5.88	$(1.50)
Common—diluted	$1.13	$0.38	$3.65	$5.84	$(1.50)
Weighted-average units used to compute net income per limited partner unit:					
Common—basic	22,208,964	11,202,427	10,975,941	10,131,928	10,071,970
Common—diluted	22,474,872	11,560,617	11,141,333	10,195,566	10,071,970
Subordinated—basic and diluted	N/A	10,071,970	10,071,970	10,071,970	10,071,970
Distributions declared per unit	$2.46	$2.22	$1.98	$1.74	$0.28
Adjusted EBITDA (3)	$109,230	$110,197	$113,348	$108,283	$76,405

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	Years Ended December 31,				
	2017	2016	2015	2014	2013
	(in thousands, except operating data)				
Cash Flow Data:					
Net cash provided by (used in):					
Operating activities	$57,042	$131,744	$287,613	$15,564	$(80,663)
Investing activities	(153,269)	(44,897)	(14,565)	(132,492)	(46,751)
Financing activities	100,286	(115,129)	(245,965)	118,390	125,959
Other Financial and Operating Data (unaudited):					
Capital expenditures	$46,955	$15,986	$14,899	$18,580	$28,090
Normal heating degree days (4)	6,750	6,785	6,749	6,749	6,752
Actual heating degree days (4)	6,255	5,993	6,707	6,855	6,624
Variance from normal heating degree days	(7)%	(12)%	(1)%	2%	(2)%
Variance from prior period actual heating degree days	4%	(11)%	(2)%	3%	14%
Total refined products volumes sold (barrels)	33,720	33,240	40,099	39,720	35,030
Variance from refined products volume from prior period	1%	(17)%	1%	13%	18%
Total natural gas volumes sold (MMBtus)	61,883	61,732	56,894	54,430	51,979
Variance from natural gas volume from prior period	—%	9%	5%	5%	5%
Balance Sheet Data (at period end):					
Cash and cash equivalents	$6,815	$2,682	$30,974	$4,080	$2,046
Property, plant and equipment, net	350,059	251,101	250,909	250,126	198,476
Total assets	1,362,985	1,012,474	1,000,332	1,339,840	1,090,241
Total debt (including capital lease obligations)	728,666	561,259	621,100	822,307	576,385
Total liabilities	1,231,151	887,037	842,847	1,223,946	1,018,948
Total unitholders'/member's equity	131,834	125,437	157,485	115,894	71,293

(1) Prior to the completion of our initial public offering (the "IPO"), Sprague Energy Corp., which was converted into a limited liability company and renamed Sprague Operating Resources LLC on November 7, 2011, prepared its income tax provision as if it had filed a consolidated U.S. federal income tax return and state tax returns as required. Commencing with the closing of the IPO, the Partnership is treated as a pass through entity for U.S. 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. The Partnership's Canadian entities are subject to Canadian income tax.

(2) Calculated based on operations since October 30, 2013, the date of the closing of the IPO.

(3) We define EBITDA as net income (loss) before interest, income taxes, depreciation and amortization. We define adjusted EBITDA as EBITDA increased by unrealized hedging losses and decreased by unrealized hedging gains, in each case with respect to refined products and natural gas inventory, prepaid forward contracts and natural gas transportation contracts, changes in the fair value of contingent consideration, the net impact of biofuel excise tax credits in 2017 and 2013; and, commencing in 2017 the impact of acquisition related expenses. Adjusted EBITDA for periods prior to 2017 have been revised to exclude acquisition related expenses to conform to the 2017 presentation.

For a discussion of the non-GAAP financial measure EBITDA and adjusted EBITDA, please read "Non-GAAP Financial Measures" in Item 7 - "Management's Discussion and Analysis of Financial Condition and Results of Operations".

(4) 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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Reconciliation of Net Income (Loss) to EBITDA and Adjusted EBITDA

The following table presents a reconciliation of net income (loss) to EBITDA and adjusted EBITDA, on a historical basis, as applicable, for each of the years indicated:

	Years Ended December 31,				
	2017	2016	2015	2014	2013
	(in thousands)				
Net income (loss)	$29,497	$10,166	$78,348	$122,814	$(29,838)
Add/(deduct):					
Interest expense, net	31,006	27,145	26,911	29,082	30,310
Tax expense (benefit)	3,822	2,108	1,816	5,509	4,259
Depreciation and amortization	28,125	21,237	20,342	17,625	16,515
EBITDA	$92,450	$60,656	$127,417	$175,030	$21,246
Add: unrealized loss (gain) on inventory derivatives (1)	124	31,304	2,079	(11,070)	4,188
Add: unrealized (gain) loss on prepaid forward contract derivatives (2)	(1,076)	(1,552)	2,628	—	—
Add: unrealized loss (gain) on natural gas transportation contracts (3)	10,441	18,612	(21,695)	(58,694)	55,745
Other adjustments (4)	231	—	—	—	—
Biofuel excise tax credits (5)	4,022	—	—	—	(5,021)
Adjusted EBITDA -as previously reported	$106,192	$109,020	$110,429	$105,266	$76,158
Acquisition related expenses (6)	3,038	1,177	2,919	3,017	247
Adjusted EBITDA -as revised	$109,230	$110,197	$113,348	$108,283	$76,405

(1) Inventory is valued at the lower of cost or net realizable value. The fair value of the derivatives we use to economically hedge our inventory declines or appreciates in value as the value of the underlying inventory appreciates or declines, which creates unrealized hedging losses (gains) with respect to the derivatives that are included in net income (loss).

(2) The unrealized hedging (gain) loss on prepaid forward contract derivatives represents our estimate of the change in fair value of the prepaid forward contracts which are not recorded in net income (loss) until the forward contract is settled in the future (i.e., when the commodity is delivered to the customer). As these contracts are prepaid, they do not qualify as derivatives and changes in the fair value are therefore not included in net income (loss). The fair value of the derivatives we use to economically hedge our prepaid forward contracts declines or appreciates in value as the value of the underlying prepaid forward contract appreciates or declines, which creates unrealized hedging (gains) losses that are included in net income (loss).

(3) The unrealized hedging (gain) loss on natural gas transportation contracts represents our estimate of the change in fair value of the natural gas transportation contracts which are not recorded in net income (loss) until the transportation is utilized in the future (i.e., when natural gas is delivered to the customer), as these contracts are executory contracts that do not qualify as derivatives. As the fair value of the natural gas transportation contracts decline or appreciate, the offsetting physical or financial derivative will also appreciate or decline creating unmatched unrealized hedging (gains) losses in net income (loss).

(4) Represents the change in the fair value of the contingent consideration related to the 2017 Coen Energy acquisition and accretion expense.

(5) On February 9, 2018 and January 2, 2013, the U.S. federal government enacted legislation that reinstated an excise tax credit program available for certain of our biofuel blending activities and in both cases the program was reinstated retroactively to January 1st of the previously expired year. During the year ended December 31, 2013, we recorded excise tax credits of $5.0 million related to blending activities that occurred during the year ended December 31, 2012, and during the three months ended March 31, 2018, we expect to record excise tax credits of approximately $4.0 million that relates to blending activities that occurred during the year ended December 31,

2017. We record theses credits in the period the legislation was enacted as a reduction of cost of products sold (exclusive of depreciation and amortization) resulting in an increase in adjusted gross margin. These adjustments reflect the effect on our adjusted EBITDA had these credits been recorded in the period in which the blending activity took place.

(6) Beginning in the fourth quarter of 2017, we have excluded the impact of acquisition related expenses from our calculation of adjusted EBITDA. We incur expenses in connection with acquisitions and given the nature, variability of amounts, and the fact that these expenses would not have otherwise been incurred as part of our continuing operations, adjusted EBITDA now excludes the impact of acquisition related expenses. Adjusted EBITDA for periods prior to 2017 have been revised to conform to the 2017 presentation.

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

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

A reference to a “Note” herein refers to the accompanying Notes to Consolidated and Combined 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 in June 2011 by Sprague Holdings and our General Partner. We 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, operate and/or control a network of refined products and materials handling terminals strategically located throughout the Northeast United States and in Quebec, Canada that have a combined storage capacity of 14.7 million barrels for refined products and other liquid materials, as well as 2.0 million square feet of materials handling capacity. Furthermore, we have access to more than 50 third-party terminals in the Northeast United States 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.

In our refined products segment we purchase a variety of refined products, such as heating oil, diesel fuel, residual fuel oil, kerosene, jet fuel, gasoline and asphalt (primarily from refining companies, trading organizations and producers), and sell 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 directly. Our wholesale customers consist of more than 1,200 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, real estate management companies, hospitals, educational institutions, asphalt paving companies and customers engaged in the development of natural gas resources in Pennsylvania and surrounding states.

In our natural gas segment we purchase, sell and distribute natural gas to approximately 16,000 commercial and industrial customer locations across 13 states in the Northeast and Mid-Atlantic United States. We purchase the natural gas from natural gas producers and trading companies.

Our materials handling segment 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, crude oil, clay slurry, salt, gypsum, coal, petroleum coke, caustic soda, tallow, pulp and heavy equipment.

Our other operations segment includes the marketing and distribution of coal conducted in our Portland, Maine terminal, commercial trucking activity conducted by our Canadian subsidiary and our heating equipment service business.

We take title to the products we sell in our refined products and natural gas segments. 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. We do not take title to any of the products in our materials handling segment.

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Non-GAAP Financial Measures

We present the non-GAAP financial measures EBITDA, adjusted EBITDA and adjusted gross margin in this Annual Report as described below. We present the non-GAAP financial measures maintenance capital expenditures and expansion capital expenditures in this Annual Report as described below in "Liquidity and Capital Resources - Capital Expenditures".

EBITDA and Adjusted EBITDA

Management believes that adjusted EBITDA is an aid in assessing repeatable operating performance that is not distorted by non-recurring items or market volatility, the viability of acquisitions and capital expenditure projects and ability of our assets to generate sufficient revenue, that when rendered to cash, will be available to pay interest on our indebtedness and make distributions to our unitholders.

We define EBITDA as net income (loss) before interest, income taxes, depreciation and amortization. We define adjusted EBITDA as EBITDA adjusted for unrealized hedging losses and decreased by unrealized hedging gains (in each case with respect to refined products and natural gas inventory, prepaid forward contracts and natural gas transportation contracts), changes in fair value of contingent consideration, the net impact of biofuel excise tax credits in 2017 and 2013, and commencing in 2017 adjusted for the impact of acquisition related expenses. Adjusted EBITDA for periods prior to 2017 have been revised for the impact of acquisition related expenses to conform to the 2017 presentation.

EBITDA and adjusted EBITDA are used as supplemental financial measures by external users of our financial statements, such as investors, trade suppliers, research analysts and commercial banks 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 sufficient revenue, that when rendered to cash, will be available 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.

EBITDA and adjusted EBITDA are not prepared in accordance with GAAP and should not be considered alternatives to net income (loss) or operating income, or any other measure of financial performance presented in accordance with GAAP. EBITDA and adjusted EBITDA exclude some, but not all, items that affect net income (loss) and operating income (loss).

The GAAP measure most directly comparable to EBITDA and adjusted EBITDA is net income (loss). EBITDA and adjusted EBITDA should not be considered as an alternative to net income (loss) or cash provided by (used in) operating activities, 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 and should not be considered 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 (loss) 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 capital assets, depreciation and amortization expense is a necessary element of our costs and ability to generate profits, 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;

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- 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.

Adjusted Gross Margin

Management trades, purchases, stores and sells energy commodities that experience market value fluctuations. To manage the Partnership's underlying performance, including its physical and derivative positions, management utilizes adjusted gross margin. In determining adjusted gross margin, management adjusts its segment results for the impact of unrealized hedging gains and losses with regard to refined products and natural gas inventory, prepaid forward contracts and natural gas transportation contracts, which are not marked to market for the purpose of recording unrealized gains or losses in net income (loss). These adjustments align the unrealized hedging gains and losses to the period in which the revenue from the sale of inventory, prepaid fixed forwards and the utilization of transportation contracts relating to those hedges is realized in net income (loss). Adjusted gross margin is also used by external users of our consolidated financial statements to assess our economic results of operations and its commodity market value reporting to lenders.

We define adjusted gross margin as net sales less cost of products sold (exclusive of depreciation and amortization) and 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, prepaid forward contracts and natural gas transportation contracts. Adjusted gross margin has no impact on reported volumes or net sales.

Adjusted gross margin is used as supplemental financial measures by management to describe our operations and economic performance to investors, trade suppliers, research analysts and commercial banks 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 is not prepared in accordance with GAAP and should not be considered as alternatives to net income (loss) or operating income (loss) or any other measure of financial performance presented in accordance with GAAP.

We define adjusted unit gross margin as adjusted gross margin divided by units sold, as expressed in gallons for refined products, and in MMBtus for natural gas.

For a reconciliation of adjusted gross margin and adjusted EBITDA to the GAAP measures most directly comparable, see the reconciliation tables included in "Results of Operations." See "Segment Reporting" included under Note 16 to our Consolidated Financial Statements for a presentation of our financial results by reportable segment.

Management evaluates our segment performance based on adjusted gross margin. Based on the way we manage our business, it is not reasonably possible for us to allocate the components of operating expenses, selling, general and administrative expenses and depreciation and amortization among the operating segments.

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) adjusted EBITDA and adjusted gross margin (described above), (2) operating expenses, (3) selling, general and administrative (or SG&A) expenses and (4) heating degree days.

Adjusted EBITDA

Management believes that adjusted EBITDA is an aid in assessing repeatable operating performance that is not distorted by non-recurring items or market volatility, the viability of acquisitions and capital expenditure projects and ability of our assets to generate sufficient revenue, that when rendered to cash, will be available to pay interest on our indebtedness and make distributions to our unit holders. We define adjusted EBITDA as earnings before interest, taxes, and depreciation and amortization expenses that are adjusted for unrealized hedging gains and losses (in each case with respect to refined products and natural gas inventory, prepaid forward contracts and natural gas transportation contracts), changes in the fair value of

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contingent consideration, adjusted for the net impact of biofuel excise tax credits in 2017 and 2013, and beginning in 2017 adjusted for the impact of acquisition related expenses. Adjusted EBITDA for periods prior to 2017 have been revised for the impact of acquisition related expenses to conform to the 2017 presentation.

Adjusted Gross Margin

Management trades, purchases, stores and sells energy commodities that experience market value fluctuations. To manage the Partnership's underlying performance, including its physical and derivative positions, management utilizes adjusted gross margin. In determining adjusted gross margin, management adjusts its segment results for the impact of unrealized hedging gains and losses with regard to refined products and natural gas inventory, prepaid forward contracts and natural gas transportation contracts, which are not marked to market for the purpose of recording unrealized gains or losses in net income (loss). These adjustments align the unrealized hedging gains and losses to the period in which the revenue from the sale of inventory, prepaid fixed forwards and the utilization of transportation contracts relating to those hedges is realized in net income (loss).

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. 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

Selling, general and administrative expenses ("SG&A") include employee salaries and benefits, discretionary bonus, marketing costs, corporate overhead, professional fees, information technology and office space expenses. Employee wages, related employee expenses and certain rental costs included in our SG&A expenses are incurred on our behalf by our General Partner and reimbursed by us.

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 over the course of a year and can be compared to a monthly or a long-term average ("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 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.

Hedging Activities

We hedge our inventory within the guidelines set in our risk management policies. 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 net realizable value. 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 using daily independent bulk market price assessments from major pricing services (either Platts or Argus). These third-party price assessments are primarily based in large, liquid trading hubs including but not limited to, New York Harbor (NYH) or US Gulf Coast (USGC), with our inventory values determined after adjusting these prices to the various inventory locations by adding expected cost differentials (primarily freight) compared to one of these supply sources. 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.

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Similarly, we can 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 typically increase. If the market value of the transportation asset exceeds costs, we may seek to 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). If 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.

Trends and Factors that Impact our Business

This section identifies certain factors and industry-wide trends that may affect our financial performance and results of operations.

- 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, local and foreign laws and regulations regulating product quality specifications, emissions in the air, discharges to land and water, and the generation, handling, treatment, and disposal of hazardous waste and other materials. The trend in regulation has been towards additional restrictions and limitations on activities that may affect the environment. Compliance with laws and regulations may increase our overall cost of business including our capital cost to maintain and upgrade equipment and facilities.
- Growth in exploration and production of shale gas has led to expanded use of natural gas in our marketing area and provided further downstream refined products sales opportunities to support the resource development activity. Supplies of natural gas from shale formations have grown both in the Northeastern region (e.g., Marcellus and Utica Shale) and the other parts of the United States. Further expansion of domestic natural gas supplies is expected. In conjunction with the production gains, natural gas usage in the Northeast United States has increased substantially with the growth trajectory expected to continue over the next few years. A possible outgrowth of this trend could be to reduce consumption of other fuels. However, significant refined products supply and supporting service requirements are expected to continue in support of the equipment used to develop this expanded production.
- Absolute price increase or decreases can impact demand and credit risk. Commodity prices in both our refined products and natural gas segments can vary sharply due to market conditions. As commodity product prices rise, we can experience reduced demand as customers engage in conservation efforts, are exposed to a higher level of credit risk to meet customer requirements, and incur increased working capital costs for holding inventory and accounts receivable. In a lower commodity price environment our customers are generally less prone to engage in conservation efforts, we experience lower credit risk, and working capital costs to hold inventory and finance accounts receivable.

- 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 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, 2017, we generated an average of 63% of our total heating oil and residual

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fuel oil net sales during the months of November through March in the Northeast United States. 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 heating oil, residual fuel oil and natural gas we sell and the adjusted gross margins realized on those sales, whereas colder-than-normal temperatures increase demand for those products and the associated adjusted 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 "over the counter" or "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.
- Energy efficiency, new technology and alternative fuels could reduce demand for our products. Increased conservation and technological advances have adversely affected the demand for 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.
- 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. Increasing interest rates could affect our ability to access the debt capital markets on favorable terms. In addition, interest rates could be higher than current levels, causing our financing costs to increase accordingly. During the 24 months ended December 31, 2017, we hedged approximately 47% 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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Results of Operations

Overview

Our current and future results of operations may not be comparable to our historical results of operations. Our results of operations may be impacted by, among other things, swings in commodity prices, primarily in refined products and natural gas, and acquisitions or dispositions. 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 disregarded for GAAP financial reporting purposes and recorded at the lower of cost or net realizable value. Please read "-How Management Evaluates Our Results of Operations." For a description of acquisition activity during the periods presented, please read Part I. Item 1. Business -Other Acquisitions."

The following tables set forth information regarding our results of operations for the periods presented:

	Years Ended December 31,		Increase/(Decrease)	
	2017	2016	$	%
	($ in thousands)			
Net sales	$2,854,996	$2,389,998	$464,998	19 %
Cost of products sold (exclusive of depreciation and amortization)	2,602,788	2,179,089	423,699	19 %
Operating expenses	72,284	65,882	6,402	10 %
Selling, general and administrative	87,582	84,257	3,325	4 %
Depreciation and amortization	28,125	21,237	6,888	32 %
Total operating costs and expenses	2,790,779	2,350,465	440,314	19 %
Operating income	64,217	39,533	24,684	62 %
Other (expense) income	108	(114)	222	(195)%
Interest income	339	388	(49)	(13)%
Interest expense	(31,345)	(27,533)	(3,812)	14 %
Income before income taxes	$33,319	$12,274	$21,045	171 %
Income tax provision	(3,822)	(2,108)	(1,714)	81 %
Net income	$29,497	$10,166	$19,331	190 %

	Years Ended December 31,		Increase/(Decrease)	
	2016	2015	$	%
	($ in thousands)			
Net sales	$2,389,998	$3,481,914	$(1,091,916)	(31)%
Cost of products sold (exclusive of depreciation and amortization)	2,179,089	3,188,924	(1,009,835)	(32)%
Operating expenses	65,882	71,468	(5,586)	(8)%
Selling, general and administrative	84,257	94,403	(10,146)	(11)%
Depreciation and amortization	21,237	20,342	895	4 %
Total operating costs and expenses	2,350,465	3,375,137	(1,024,672)	(30)%
Operating income	39,533	106,777	(67,244)	(63)%
Other income (expense)	(114)	298	(412)	(138)%
Interest income	388	456	(68)	(15)%
Interest expense	(27,533)	(27,367)	(166)	1 %
Income before income taxes	$12,274	$80,164	$(67,890)	(85)%
Income tax provision	(2,108)	(1,816)	(292)	16 %
Net income	$10,166	$78,348	$(68,182)	(87)%

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Reconciliation to Adjusted Gross Margin, EBITDA and Adjusted EBITDA

The following table sets forth a reconciliation of our operating income to our total adjusted gross margin, a non-GAAP measure, and a reconciliation of our net income to EBITDA and Adjusted EBITDA, non-GAAP measures, for the periods presented. See above "Management's Discussion and Analysis of Financial Condition and Results of Operations-Non-GAAP Financial Measures" and "How Management Evaluates Our Results of Operations" of this report. The table below also presents information on weather conditions for the periods presented.

	Years Ended December 31,		
	2017	2016	2015
	($ in thousands)		
Reconciliation of Operating Income to Adjusted Gross Margin:			
Operating income	$64,217	$39,533	$106,777
Operating costs and expenses not allocated to operating segments:			
Operating expenses	72,284	65,882	71,468
Selling, general and administrative	87,582	84,257	94,403
Depreciation and amortization	28,125	21,237	20,342
Add: unrealized loss on inventory derivatives (1)	124	31,304	2,079
Add: unrealized (gain) loss on prepaid forward contract derivatives (2)	(1,076)	(1,552)	2,628
Add: unrealized loss (gain) on natural gas transportation contracts (3)	10,441	18,612	(21,695)
Total adjusted gross margin (5):	$261,697	$259,273	$276,002
Adjusted Gross Margin by Segment:			
Refined products	$142,467	$142,581	$170,448
Natural gas	65,060	62,435	51,004
Materials handling	46,512	45,712	45,564
Other operations	7,658	8,545	8,986
Total adjusted gross margin	$261,697	$259,273	$276,002
Reconciliation of Net Income to Adjusted EBITDA			
Net income	$29,497	$10,166	$78,348
Add:			
Interest expense, net	31,006	27,145	26,911
Tax provision	3,822	2,108	1,816
Depreciation and amortization	28,125	21,237	20,342
EBITDA (5):	$92,450	$60,656	$127,417
Add: unrealized loss on inventory derivatives (1)	124	31,304	2,079
Add: unrealized (gain) loss on prepaid forward contract derivatives (2)	(1,076)	(1,552)	2,628
Add: unrealized loss (gain) on natural gas transportation contracts (3)	10,441	18,612	(21,695)
Biofuel tax credit (4)	4,022	—	—
Other adjustments (7)	231	—	—
Adjusted EBITDA (5) - as previously recorded	$106,192	$109,020	$110,429
Acquisition related expenses (6)	3,038	1,177	2,919
Adjusted EBITDA - as revised (6)	$109,230	$110,197	$113,348
Other Data:			
Normal heating degree days (8)	6,750	6,785	6,749
Actual heating degree days (8)	6,255	5,993	6,707
Variance from normal heating degree days	(7)%	(12)%	(1)%
Variance from prior period actual heating degree days	4%	(11)%	(2)%

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(1) Inventory is valued at the lower of cost or net realizable value. The fair value of the derivatives we use to economically hedge our inventory declines or appreciates in value as the value of the underlying inventory appreciates or declines, which creates unrealized hedging losses (gains) with respect to the derivatives that are included in net income (loss).

(2) The unrealized hedging (gain) loss on prepaid forward contract derivatives represents our estimate of the change in fair value of the prepaid forward contracts which are not recorded in net income (loss) until the forward contract is settled in the future (i.e., when the commodity is delivered to the customer). As these contracts are prepaid, they do not qualify as derivatives and changes in the fair value are therefore not included in net income (loss). The fair value of the derivatives we use to economically hedge our prepaid forward contracts declines or appreciates in value as the value of the underlying prepaid forward contract appreciates or declines, which creates unrealized hedging (gains) losses that are included in net income (loss).

(3) The unrealized loss (gain) on natural gas transportation contracts represents our estimate of the change in fair value of the natural gas transportation contracts which are not recorded in net (loss) income until the transportation is utilized in the future (i.e., when natural gas is delivered to the customer), as these contracts are executory contracts that do not qualify as derivatives. As the fair value of the natural gas transportation contracts decline or appreciate, the offsetting physical or financial derivative will also appreciate or decline creating unmatched unrealized hedging losses (gains) in net (loss) income.

(4) On February 9, 2018, the U.S. federal government enacted legislation that reinstated an excise tax credit program available for certain of our biofuel blending activities. The program had expired on December 31, 2016 and was reinstated retroactively to January 1, 2017. During the three months ended March 31, 2018, we expect to record excise tax credits of approximately $4.0 million that relates to blending activities that occurred during the year ended December 31, 2017. We record the credit in the period the legislation was enacted as a reduction of cost of products sold (exclusive of depreciation and amortization) resulting in an increase in adjusted gross margin. These adjustments reflect the effect on our adjusted EBITDA had these credits been recorded in the period in which the blending activity took place.

(5) For a discussion of the non-GAAP financial measures EBITDA, adjusted EBITDA and adjusted gross margin, see “How Management Evaluates Our Results of Operations.”

(6) Beginning in the fourth quarter of 2017, we have excluded the impact of acquisition related expenses from our calculation of adjusted EBITDA. We incur expenses in connection with acquisitions and given the nature, variability of amounts, and the fact that these expenses would not have otherwise been incurred as part of our continuing operations, adjusted EBITDA excludes the impact of acquisition related expenses. Adjusted EBITDA for periods prior to 2017 have been revised to conform to the 2017 presentation.

(7) Represents the change in the fair value of contingent consideration related to the 2017 Coen Energy acquisition and other expense.

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

Analysis of Consolidated Operating Results

For the years ended December 31, 2017 and 2016, our net income was $29.5 million and $10.2 million, respectively and operating income was $64.2 million and $39.5 million, respectively. Operating results for the years ended December 31, 2017 and 2016, include unrealized commodity derivative gains and (losses) with respect to refined products and natural gas inventory, prepaid forward contracts and natural gas transportation contracts of $(9.5) million and $(48.4) million, respectively. Excluding these non-cash items, operating income decreased $14.2 million compared to the year ended December 31, 2016. This decrease was primarily attributable to the decreased weather driven demand during the mild winter weather in the first quarter of the year.

For the years ended December 31, 2016 and 2015, our net income was $10.2 million and $78.3 million, respectively and operating income was $39.5 million and $106.8 million, respectively. Operating results for the years ended December 31, 2016 and 2015 include unrealized commodity derivative gains and (losses) with respect to refined products and natural gas inventory, prepaid forward contracts and natural gas transportation contracts of $(48.4) million and $17.0 million, respectively. Excluding these non-cash items, operating income decreased $1.9 million compared to the years ended December 31, 2015. This decrease was primarily attributable to the significantly warmer weather conditions that occurred during the first quarter of 2016. These negative impacts were partially offset by lower incentive related employee costs and lower operating costs at our terminals.

See "Analysis of Operating Segments" and "Liquidity and Capital Resources" below for additional details on operating results.

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Analysis of Operating Segments

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

	Years Ended December 31,		Increase/(Decrease)	
	2017	2016	$	%
	($ and volumes in thousands, except adjusted unit gross margin)			
Volumes:				
Refined products (gallons)	1,416,240	1,396,080	20,160	1 %
Natural gas (MMBtus)	61,883	61,732	151	— %
Materials handling (short tons)	2,366	2,523	(157)	(6)%
Materials handling (gallons)	385,896	276,402	109,494	40 %
Net Sales:				
Refined products	$2,455,577	$1,988,597	$466,980	23 %
Natural gas	331,669	334,003	(2,334)	(1)%
Materials handling	46,513	45,734	779	2 %
Other operations	21,237	21,664	(427)	(2)%
Total net sales	$2,854,996	$2,389,998	$464,998	19 %
Adjusted Gross Margin:				
Refined products	$142,467	$142,581	$(114)	— %
Natural gas	65,060	62,435	2,625	4 %
Materials handling	46,512	45,712	800	2 %
Other operations	7,658	8,545	(887)	(10)%
Total adjusted gross margin	$261,697	$259,273	$2,424	1 %
Adjusted Unit Gross Margin:				
Refined products	$0.101	$0.102	$(0.001)	(1)%
Natural gas	$1.051	$1.011	$0.040	4 %

Refined Products

Refined products net sales increased $0.5 billion, or 23%, principally due to a 22% increase in the average sales price in the higher oil price environment. The 1% gain in product volume was a minor contributor to the higher sales. Refined products adjusted gross margin increased $0.1 million due to the higher volumes. This volume increase was a result of acquisitions during the year, in particular L.E. Belcher and Coen Energy. The acquisition-led volume gains more than offset other reductions resulting from lower activity in the early part of the year with the milder winter weather.

The volume gains were due to growth in distillates, with lower gasoline and to a lesser extent heavy oil volumes offsetting part of this increase. The lower gasoline volume was primarily a result of the highly competitive market for discretionary volumes along with the loss of a municipal bid contract. The reduction in heavy oil volume was primarily the result of decreased weather-driven demand during the mild winter weather in the first quarter of the year. Overall unit margins were consistent with 2016 results despite the high competitive pressure in the early part of the year with the milder weather conditions.

Natural Gas

Natural gas net sales decreased $2.3 million, due to a 1% decrease in average unit sales price. The lower sales price was partially offset by a modest gain in volume, with the impact of the Global Natural Gas & Power acquisition completed at the beginning of February more than compensating for the volume decline in the rest of the business. This volume reduction was primarily due to the loss of certain higher volume, lower adjusted unit gross margin accounts.

Natural gas adjusted gross margin increased $2.6 million, or 4%, due to a 4% gain in adjusted unit gross margin. The higher unit margins resulted primarily from improved margin opportunities on customer sales partially offset by fewer pipeline capacity optimization opportunities.

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Materials Handling

Materials handling net sales and adjusted gross margin both increased $0.8 million, or 2%, compared to last year. The gain was principally the result of a $3.0 million increase in asphalt revenue primarily due to new agreements at two terminals. Other increases included higher bulk handling (principally salt) and, to a lesser degree, increased activity at Kildair. These gains more than offset the $2.7 million decline in wind energy component handling driven by uncertainty regarding the level of government support of the renewable fuels production tax credit.

Other Operations

Net sales from other operations declined by $0.4 million, or 2%, with adjusted gross margin $0.9 million lower, a 10% decline. The decline in adjusted gross margin was a combination of volume reductions in coal due to decreased customer requirements and to a lesser extent trucking activity at Kildair and fuel burner service.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

	Years Ended December 31,		Increase/(Decrease)	
	2016	2015	$	%
	($ and volumes in thousands, except adjusted unit gross margin)			
Volumes:				
Refined products (gallons)	1,396,080	1,684,158	(288,078)	(17)%
Natural gas (MMBtus)	61,732	56,894	4,838	9 %
Materials handling (short tons)	2,523	2,666	(143)	(5)%
Materials handling (gallons)	276,402	266,280	10,122	4 %
Net Sales:				
Refined products	$ 1,988,597	$ 3,063,858	$ (1,075,261)	(35)%
Natural gas	334,003	347,453	(13,450)	(4)%
Materials handling	45,734	45,570	164	— %
Other operations	21,664	25,033	(3,369)	(13)%
Total net sales	$ 2,389,998	$ 3,481,914	$ (1,091,916)	(31)%
Adjusted Gross Margin:				
Refined products	$ 142,581	$ 170,448	$ (27,867)	(16)%
Natural gas	62,435	51,004	11,431	22 %
Materials handling	45,712	45,564	148	— %
Other operations	8,545	8,986	(441)	(5)%
Total adjusted gross margin	$ 259,273	$ 276,002	$ (16,729)	(6)%
Adjusted Unit Gross Margin:				
Refined products	$ 0.102	$ 0.101	$ 0.001	1 %
Natural gas	$ 1.011	$ 0.896	$ 0.115	13 %

Refined Products

Refined products net sales decreased $1.1 billion, or 35%, due to combination of a 22% decrease in the average sales price as a result of a lower commodity price environment and a 17% reduction in product volumes.

Refined products adjusted gross margin decreased $27.9 million or 16%, primarily as a result of lower volumes during the early part of the year driven by the milder winter weather (25% reduction in heating degree days during the first quarter). Other factors leading to the reduced volumes included a highly competitive market for discretionary volumes and the loss of some higher-volume commercial bid contracts and an improved market structure for carrying distillate inventory. Sales volume was lower in all three product groups, with distillates comprising nearly two-thirds of the reduction, principally due to lower heating oil requirements. Gasoline and heavy oil volumes were down comparable amounts, driven by high competitive intensity for gasoline and the continuing decline in heavy oil demand. Overall adjusted unit gross margins were consistent with 2015 despite the competitive pressure in the early part of the year with the milder weather conditions.

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Natural Gas
Natural gas net sales decreased $13.5 million, or 4%, as a result of an 11% reduction in average unit sales price from the lower commodity price environment partially offset by increased sales volume as discussed below.
Natural gas adjusted gross margin increased $11.4 million, or 22%, due to the combination of both higher volume and adjusted unit margin. The 9% increase in volume was a result of the SBE natural gas transaction, which more than offset the reduced underlying demand during the mild winter. The higher unit margins resulted from a variety of factors including gains in the valuation of forward contracts, narrowing credit spreads, and enhanced optimization of pipeline capacity.
Materials Handling
Materials handling net sales and adjusted gross margin remained relatively steady, with increases of $0.2 million and $0.1 million, respectively. Net sales and adjusted gross margin were stronger at Kildair by $1.7 million due to higher heavy oil storage and handling revenues. Excluding Kildair, net sales and adjusted gross margin were $1.6 million lower due to decreased salt and petroleum coke handling requirements following high volumes in 2015, as well as reductions in various break bulk product requirements. Partially offsetting these declines were increases in a number of dry and liquid bulk product volumes.
Other Operations
Net sales from other operations decreased $3.4 million, or 13%, primarily as a result of reduced coal prices.
Adjusted gross margin from other operations decreased $0.4 million, or 5%, primarily from decreased coal results.

Operating Costs and Expenses
Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

	Years Ended December 31,		Increase/(Decrease)	
	2017	2016	$	%
	($ in thousands)			
Operating expenses	$72,284	$65,882	$ 6,402	10 %
Selling, general and administrative expenses	$87,582	$84,257	$ 3,325	4 %
Depreciation and amortization	$28,125	$21,237	$ 6,888	32 %
Interest expense, net	$31,006	$27,145	$ 3,861	14 %

Operating Expenses. Operating expenses increased $6.4 million, or 10%, reflecting $6.9 million of operating expenses at the four refined products businesses acquired during 2017, offset by a $1.0 million decrease in stockpile expenses.
Selling, General and Administrative Expenses. Selling, general and administrative expenses increased $3.3 million, or 4%, led by a $3.0 million increase attributable to the Global Natural Gas & Power and Coen Energy acquisitions, a $1.9 million increase in merger and acquisition expenses and a $0.6 million increase in systems costs in support of continued growth. These increases were partially offset by a $2.5 million decrease in employee related costs driven by decreased incentive compensation.
Depreciation and Amortization. Depreciation and amortization increased $6.9 million, or 32%, primarily as a result of the five acquisitions completed in 2017.
Interest Expense, net. Interest expense, net increased $3.9 million, or 14%, primarily due to increased borrowings for the five acquisitions completed in 2017 and a one-time charge attributable to the refinancing and extension of our credit agreement.

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Year Ended December 31, 2016 Compared to Year Ended December 31, 2015

	Years Ended December 31,		Increase/(Decrease)	
	2016	2015	$	%
	($ in thousands)			
Operating expenses	$65,882	$71,468	$(5,586)	(8)%
Selling, general and administrative expenses	$84,257	$94,403	$(10,146)	(11)%
Depreciation and amortization	$21,237	$20,342	$895	4%
Interest expense, net	$27,145	$26,911	$234	1%

Operating Expenses. Operating expenses decreased $5.6 million, or 8%, driven by a $1.8 million decrease in employee related costs, a $1.7 million decrease in maintenance and utility expenses at our terminals and a $1.7 million decrease in boiler and vehicle fuel costs at our terminals as a result of lower commodity prices

Selling, General and Administrative Expenses. Selling, general and administrative expenses decreased $10.1 million, or 11%, reflecting lower employee related expenses of $6.5 million primarily attributable to decreased incentive compensation driven by lower distributable cash flow, $2.4 million of decreased professional fees and $1.7 million of decreased merger related expenses.

Depreciation and Amortization. Depreciation and amortization increased $0.9 million, or 4%, reflecting a $1.2 million increase in the amortization of intangible assets as a result of the SBE acquisition which was partially offset by reduced amortization of our other intangible assets.

Interest Expense, net. Interest expense, net increased $0.2 million, or 1%, primarily due to higher expense related to the commitment fees related to increased capacity of our acquisition facility, partially offset by lower working capital requirements as a result of lower commodity prices and lower acquisition borrowings.

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 our credit agreement and potential future issuances of additional partnership interests or debt securities are our primary sources of liquidity. At December 31, 2017, our working capital was $102.3 million.

As of December 31, 2017, the undrawn borrowing capacity under the working capital facility was $209.0 million and the undrawn borrowing capacity under the acquisition facility was $166.5 million. 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, typically inventory is reduced, accounts receivable are collected and converted into cash and debt is paid down. During the twelve months ended December 31, 2017, the amount drawn under the working capital facility of our credit agreements fluctuated from a low of $115.0 million to a high of $344.0 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.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements.

Capital Expenditures

Our terminals require investments to maintain, 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. We define maintenance capital expenditures as 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

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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. We define expansion capital expenditures as 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.

The following table summarizes expansion and maintenance capital expenditures for the periods indicated. This information excludes property, plant and equipment acquired in business combinations.

	Capital Expenditures		
	Expansion	Maintenance	Total
	($ in thousands)		
Years Ended December 31,			
2017 (1)	$26,870	$ 11,521	$38,391
2016	$7,518	$ 8,468	$15,986
2015	$7,134	$ 7,765	$14,899

(1) Excludes approximately $8.6 million of assets acquired in 2017 that were previously leased by the Partnership.

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, 2017 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)	$32,179	$12,177	$14,416	$3,309	$ 2,277
Capital lease obligations (including interest)	3,122	948	1,466	701	7
Credit facilities (including interest) (2)	813,064	107,122	705,942	—	—
Product purchases (3)	411,580	403,234	8,346	—	—
Transportation and storage (4)	29,331	15,219	11,942	2,170	—
Contingent consideration (including discount) (5)	11,400	2,000	9,400	—	—
Deferred consideration (6)	35,638	$3,818	$7,637	7,637	16,546
Total	$1,336,314	$544,518	$759,149	$13,817	$ 18,830

(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.

(2) Amounts include principal and interest on our working capital revolving credit facility and our acquisition line revolving credit facility at December 31, 2017. The credit agreement has a contractual maturity of December 9, 2019 and no scheduled 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, 2017, 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

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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.

(5) Contingent consideration payments are related to the Coen Energy acquisition. The amount is remeasured at fair value every reporting period with the change in fair value recorded in general and administrative expenses (see Notes 2 and 13, of Part II, Item 8 of this Annual Report on Form 10-K). The actual amount ultimately paid out may be different depending on the level of achievement of certain operating milestones.

(6) Deferred consideration payments are related to the Carbo acquisition (see Notes 2 and 13, of Part II, Item 8 of this Annual Report on Form 10-K).

Cash Flows

	Years Ended December 31,		
	2017	2016	2015
	(in thousands)		
Net cash provided by operating activities	$57,042	$131,744	$287,613
Net cash used in investing activities	$(153,269)	$(44,897)	$(14,565)
Net cash provided by (used in) financing activities	$100,286	$(115,129)	$(245,965)

Operating Activities

Net cash provided by operating activities for the year ended December 31, 2017 was $57.0 million and was favorably impacted by an increase of $71.5 million in accounts payable and accrued liabilities due to timing of payments and higher commodity prices and a decrease of $24.8 million in derivative instruments as a result of the increase in commodity prices in refined products and natural gas during the last two months of the year and net income of $29.5 million. Cash flows from operations were negatively impacted by an increase of $94.5 million in accounts receivable, primarily related to higher commodity prices as well as an increase of $12.2 million in inventory.

Net cash provided by operating activities for the year ended December 31, 2016 was $131.7 million and was favorably impacted by a decrease of $165.1 million in derivative instruments as a result of the increase in commodity prices in refined products and natural gas during the last two months of the year and an increase of $47.7 million in accounts payable and accrued liabilities due to timing of payments and higher commodity prices. Cash flows from operations were negatively impacted by an increase of $77.2 million in inventory, as well as an increase of $61.5 million in accounts receivable, primarily related to higher commodity prices.

Net cash provided by operating activities for the year ended December 31, 2015 was $287.6 million and was favorably impacted by a decrease of $149.2 million in inventory, and a decrease of $127.2 million in accounts receivable primarily related to lower commodity prices and net income of $78.3 million. Cash flows from operations were negatively impacted by a decrease of $127.4 million in accounts payable and accrued liabilities due to timing of payments and lower commodity prices.

Investing Activities

Net cash used in investing activities for the year ended December 31, 2017 was $153.3 million and consisted primarily of $107.3 million related to the net cash used to finance our acquisitions, $11.5 million related to maintenance capital expenditures, $26.9 million related to expansion capital expenditures across our terminal system and $8.6 million related to a purchase of real estate previously leased by us at our Portland Merrill terminal.

Net cash used in investing activities for the year ended December 31, 2016 was $44.9 million and consisted primarily of $29.1 million related to the net cash used to finance our acquisition, $8.5 million related to maintenance capital expenditures and $7.5 million related to expansion capital expenditures across our terminal system.

Net cash used in investing activities for the year ended December 31, 2015 was $14.6 million and consisted primarily of $7.1 million related to expansion capital expenditures and $7.8 million related to maintenance capital expenditure projects across our terminal system.

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Financing Activities

Net cash provided by financing activities for the year ended December 31, 2017 was $100.3 million, and primarily resulted from $169.2 million of net borrowings under our credit agreement due to financing activity related to the acquisitions, increased financing requirements from higher commodity prices, year-end timing of accounts receivable levels and average higher inventory levels, which was partially offset by an increase of accounts payable. In addition, distributions to unitholders were $57.5 million.

Net cash used in financing activities for the year ended December 31, 2016 was $115.1 million, and primarily resulted from $59.9 million of net payments under our credit agreement due to decreased financing requirements from lower values on the derivative instruments and timing of accounts payable which was partially offset by average higher inventory levels, higher commodity prices and year end timing of accounts receivable levels. In addition, distributions to unitholders were $47.5 million.

Net cash used in financing activities for the year ended December 31, 2015 was $246.0 million, and primarily resulted from $198.9 million of net payments under our credit agreement due to reduced financing requirements from lower inventory levels, lower commodity prices and accounts receivable levels, and distributions to unitholders of $40.6 million.

Credit Agreement

On April 27, 2017, Sprague Operating Resources LLC and Kildair entered into an agreement that amended and restated the revolving credit agreement (our "Credit Agreement") to extend the maturity date through April 27, 2021, reduce the U.S. dollar working capital facility from $1.0 billion to $950.0 million, reduce the multicurrency working capital facility from $120.0 million to $100.0 million, reduce interest rates margins for the acquisition facilities under certain leverage ratio scenarios, as well as make other modifications. Obligations under the Credit Agreement are secured by substantially all of the assets of the Partnership and its subsidiaries.

As of December 31, 2017, the revolving credit facilities under the Credit Agreement contained, among other items, the following:

- A U.S. dollar revolving working capital facility of up to $950.0 million, subject to the Partnership's borrowing base limits, to be used for working capital loans and letters of credit;
- A multicurrency revolving working capital facility of up to $100.0 million, subject to the Partnership's borrowing base limits, to be used for working capital loans and letters of credit; and
- A revolving acquisition facility of up to $550.0 million, subject to the Partnership's acquisition facility borrowing base limits, to be used for loans and letters of credit to fund capital expenditures and acquisitions and other general corporate purposes related to the Partnership’s current businesses, and
- Subject to certain conditions including the receipt of additional commitments from lenders, the ability to increase the U.S. dollar revolving working capital facilities by $250.0 million and the multicurrency revolving working capital facility by $220.0 million, subject to a maximum increase for both facilities of $270.0 million in the aggregate. Additionally, subject to certain conditions, the revolving acquisition facility may be increased by $200.0 million.

Indebtedness under the Credit Agreement bears interest, at the borrowers' option, at a rate per annum equal to either (i) the Eurocurrency Rate (which is the LIBOR Rate for loans denominated in U.S. dollars and CDOR for loans denominated in Canadian dollars, in each case adjusted for certain regulatory costs) for interest periods of one, two, three or six months plus a specified margin or (ii) an alternate rate plus a specified margin.

For loans denominated in U.S. dollars, the alternate rate is the Base Rate which is the highest of (a) the U.S. Prime Rate as in effect from time to time, (b) the greater of the Federal Funds Effective Rate and the Overnight Bank Funding Rate as in effect from time to time plus 0.50% and (c) the one-month Eurocurrency Rate for U.S. dollars as in effect from time to time plus 1.00%.

For loans dominated in Canadian dollars, the alternate rate is the Prime Rate which is the higher of (a) the Canadian Prime Rate as in effect from time to time and (b) the one-month Eurocurrency Rate for U.S. dollars as in effect from time to time plus 1.00%.

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The specified margin for the working capital facilities will range, based upon the percentage utilization of this facility, from 1.00% to 1.50% for loans bearing interest at the alternative Base Rate and from 2.00% to 2.50% for loans bearing interest at the Eurocurrency Rate and for letters of credit issued under the U.S. dollar working capital facility or the multicurrency working capital facility. The specified margin for the acquisition facility will range, based on the Partnership's consolidated total leverage ratio, from 1.25% to 2.25% for loans bearing interest at the alternate Base Rate and from 2.25% to 3.25% for loans bearing interest at the Eurocurrency Rate and for letters of credit issued under the acquisition facility. In addition, the Partnership will incur a commitment fee on the unused portion of the facilities at a rate ranging from 0.375% to 0.50% per annum. Overdue amounts bear interest at the applicable rates described above plus an additional margin of 2%.

The Credit Agreement contains various covenants and restrictive provisions that, among other things, prohibit the Partnership from making distributions to unitholders if any event of default occurs or would result from the distribution or if the Partnership would not be in pro forma compliance with its financial covenants after giving effect to the distribution. In addition, the Credit Agreement contains various covenants that are usual and customary for a financing of this type, size and purpose, including, among others require the Partnership to maintain: a minimum consolidated EBITDA-to-fixed charge ratio, a minimum consolidated Net Working Capital amount, a maximum consolidated total leverage-to-EBITDA ratio and a maximum consolidated senior secured leverage-to-EBITDA ratio. The credit agreement also limits the Partnership's ability to incur debt, grant liens, make certain investments or acquisitions, dispose of assets, and incur additional indebtedness. The Partnership was in compliance with the covenants under the Credit Agreement at December 31, 2017.

The Credit Agreement also contains events of default that are usual and customary for a financing of this type, size and purpose including, among others, non-payment of principal, interest or fees, violation of certain covenants, material inaccuracy of representations and warranties, bankruptcy and insolvency events, cross-payment default and cross-acceleration, material judgments and events constituting a change of control. If an event of default exists under the Credit Agreement, the lenders will be able to terminate the lending commitments, accelerate the maturity of the Credit Agreement and exercise other rights and remedies with respect to the collateral.

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, 2017, 2016 and 2015.

Foreign Currency

Our most significant foreign operations are conducted by Kildair, our Canadian subsidiary. The functional currency of Kildair is the U.S. Dollar.

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 Canadian 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 (loss) as these forward currency contracts have not been designated as hedges. Transaction exchange gains or losses net of the impact of the forward currency exchange contracts, except for certain transaction gains or losses related to intercompany receivable and payables, are recorded in cost of products sold (exclusive of depreciation and amortization). 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 (loss) and are recorded as a translation adjustment to accumulated other comprehensive income (loss) as a component of member's/unitholders' equity. As of December 31, 2016, all intercompany receivables or payables are anticipated to be settled in the foreseeable future and therefore, no amounts are included in accumulated other comprehensive income (loss).

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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 the Partnership to make estimates and assumptions that affect the reported amounts of assets and liabilities in the balance sheet and reported net sales and expenses in the income statement. Actual results could differ from those estimates. Among the estimates made by the Partnership are assets and liabilities valuations as part of an acquisition, the fair value of derivative assets and liabilities, valuation of contingent consideration, valuation of the reporting units within the goodwill impairment assessment, and if necessary long-lived asset impairments and environmental and legal obligations.

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 (exclusive of depreciation and amortization).

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 (loss) and accumulated other comprehensive loss, net of tax, respectively.

Our derivative instruments are recorded at fair value, with changes in fair value recognized in net income (loss) or other comprehensive income (loss) 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 based on 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 ("OTC") 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 net realizable value. Cost is primarily determined using the first-in, first-out method, except for Kildair which uses the weighted-average 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 31 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 2017 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 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 (exclusive of depreciation and amortization).

Recent Accounting Pronouncements

For information on recent accounting pronouncements impacting our business, see "Recent Accounting Pronouncements" included under Note 1 to our Consolidated Financial Statements (Part II, Item 8 of this Annual Report).

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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 swaps to manage exposure to interest rate risk.

Commodity Price Risk

We use various financial instruments as we seek to hedge our commodity price risk. We sell our refined products and natural gas primarily in the Northeast. We hedge our refined products positions primarily with a combination of futures contracts that trade on the NYMEX, and fixed-for-floating price swaps in the form of bilateral contracts that are traded “over-the-counter” or "OTC". 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 hedging residual fuel oils. 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 Oil	New York Harbor 1% Sulfur Residual Fuel Oil Swaps

In addition to the financial instruments listed above, we periodically 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. We also use Rotterdam Barge 0.1% Sulfur Gasoil swaps as the primary means to hedge Kildair's marine gas oil positions.

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 by using forward purchases or sales that require physical delivery of the product.

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 (exclusive of depreciation and amortization) for the years ended December 31, 2017, 2016 and 2015:

	2017	2016	2015
	(in thousands)		
Refined products contracts	$12,856	$(25,316)	$149,741
Natural gas contracts	(1,555)	7,153	19,824
Total	$11,301	$(18,163)	$169,565

Substantially all of our commodity derivative contracts outstanding as of December 31, 2017 will settle prior to June 30, 2019.

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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. 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.

The Partnership's interest rate swap agreements outstanding as of December 31, 2017 were as follows:

Interest Rate Swap Agreements

Beginning	Ending	Notional Amount (in thousands)
January 2017	January 2018	$ 225,000
January 2018	January 2019	$ 275,000
January 2019	January 2020	$ 175,000
January 2020	January 2021	$ 100,000
January 2021	January 2022	$ 100,000
January 2022	January 2023	$ 50,000

During the two year period ended December 31, 2017, we hedged approximately 47% of our floating rate debt with fixed-for-floating interest rate swaps. We expect to continue to utilize interest rate swaps to manage our exposure to LIBOR interest rates. Based on a sensitivity analysis for the year ended December 31, 2017, we estimate that if short-term interest rates increase 100 basis points or decrease to zero, our interest expense would increase by $3.2 million and decrease by $3.1 million, respectively. These amounts were estimated by considering the effect of the hypothetical short-term interest rates on variable-rate debt outstanding, adjusted for interest rate hedges.

Derivative Instruments

The following tables present all of our derivative assets and derivative liabilities measured at fair value on a recurring basis as of December 31, 2017:

	Fair Value Measurement	Active Markets Level 1	Observable Inputs Level 2	Unobservable Inputs Level 3
	(in thousands)			
Derivative assets:				
Commodity fixed forwards	$ 11,502	$ —	$ 11,502	$ —
Commodity swaps and options	100,630	100,613	17	—
Commodity derivatives	112,132	100,613	11,519	—
Interest rate swaps	2,615	—	2,615	—
Total derivative assets	$ 114,747	$ 100,613	$ 14,134	$ —
Derivative liabilities:				
Commodity fixed forwards	$ 61,195	$ —	$ 61,195	$ —
Commodity swaps and options	103,827	103,654	173	—
Commodity derivatives	165,022	103,654	61,368	—
Interest rate swaps	6	—	6	—
Total derivative liabilities	$ 165,028	$ 103,654	$ 61,374	$ —

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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 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. Control measures include volumetric, value at risk, and stop loss limits, as well as contract term limits. Our Chief Risk Officer and Risk Management Committee 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 a value at risk model to monitor 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, credit insurance with a third party provider and accepting personal guarantees and 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		
	2017	2016	2015	2017	2016	2015
	(in thousands)			(in thousands)		
At December 31	$ 67	$ 49	$ 85	$ 341	$ 325	$ 237
Average	85	107	193	223	346	243
High	545	282	1,863	421	1,248	617
Low	21	26	25	120	129	117

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Item 8. Financial Statements and Supplementary Data

See Part IV, Item 15 - “Index to Consolidated and Combined 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

Disclosure controls and procedures are designed to ensure that information required to be disclosed in the Partnership's reports filed or submitted 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 in the Partnership's reports under the Exchange Act is accumulated and communicated to the Partnership's management, including its President and Chief Executive Officer and Senior Vice President, Chief Operating Officer and Chief Financial Officer of Sprague Resources GP LLC (the Partnership's general partner), or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

As of December 31, 2017, the Partnership carried out an evaluation, under the supervision and with the participation of management (including the President and Chief Executive Officer and the Senior Vice President, Chief Operating Officer and Chief Financial Officer of the Partnership's general partner) of the effectiveness of the design and operation of the Partnership's disclosure controls and procedures pursuant to Exchange Act Rule 13a-15. Based on this evaluation, the general partner's President and Chief Executive Officer and Senior Vice President, Chief Operating Officer and Chief Financial Officer concluded that the Partnership's disclosure controls and procedures were effective as of December 31, 2017.

Management’s Report Regarding Internal Control Over Financial Reporting

Management of the general partner, including the President and Chief Executive Officer and the Senior Vice President, Chief Operating Officer and Chief Financial Officer of the Partnership's general partner, is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes in accordance with accounting principles generally accepted in the United States of America. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Further, because of changes in conditions, effectiveness of internal control over financial reporting may vary over time.

In February 2017 and October 2017, Sprague Resources LP acquired Global Natural Gas and Power and Coen Energy for $16.3 million and $44.9 million, respectively. Since the Partnership has not yet fully incorporated the internal controls and procedures of these acquisitions into its internal control over financial reporting, management excluded this business from its assessment of the effectiveness of internal control over financial reporting as of December 31, 2017. These acquisitions accounted for 3% of Sprague Resources LP’s total assets as of December 31, 2017 and 2% of net revenue and net income, respectively, for the year then ended.

Management has assessed the effectiveness of Sprague Resources LP’s internal control over financial reporting as of December 31, 2017, with the exception of the aforementioned acquisitions. In making its assessment, management has utilized the criteria set forth by the Committee of Sponsoring Organizations (COSO) of the Treadway Commission in Internal Control—Integrated Framework (2013 Framework). Management concluded that based on its assessment, Sprague Resource’s internal control over financial reporting was effective as of December 31, 2017. Ernst & Young LLP, Registered Public Accounting Firm, has issued an attestation report on our internal control over financial reporting which is included in this annual report on page F-3.

Changes In Internal Control Over Financial Reporting

There have been no changes in our system of internal control over financial reporting during the three months ended December 31, 2017 that have materially affected, or are reasonably likely to materially affect, the Partnership’s internal control over financial reporting.

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 our 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. The board of directors of our General Partner met four times during the 2017 fiscal year and each of its directors attended 100% of the meetings. The audit committee of the board of directors of our General Partner met seven times during the 2017 fiscal year and each of its members attended 100% of such meetings. The conflicts committee of the board of directors of our General Partner did not meet during the 2017 fiscal year.
The following table provides information as of March 6, 2018 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	54	Chairman of the Board of Directors
Sally A. Sarsfield	58	Director
Ben J. Hennelly	47	Director
C. Gregory Harper	53	Director
Robert B. Evans	69	Director
Beth A. Bowman	61	Director
David C. Glendon*	52	President, Chief Executive Officer and Director
Gary A. Rinaldi*	60	Senior Vice President, Chief Operating Officer, Chief Financial Officer and Director
John W. Moore*	59	Vice President, Chief Accounting Officer
Thomas F. Flaherty*	62	Vice President, Refined Products
Steven D. Scammon*	56	Vice President, Chief Risk Officer
Joseph S. Smith*	61	Vice President, Business Development
Paul A. Scoff*	58	Vice President, General Counsel, Chief Compliance Officer and Secretary
James Therriault*	57	Vice President, Materials Handling
Brian W. Weego*	51	Vice President, Natural Gas
Kevin G. Henry	57	Vice President, Treasurer
Burton S. Russell	62	Vice President, Operations
Gillian H. Tierney	49	Vice President, Human Resources

*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 also serves on the board of ConforMIS Inc., a medical technology company. Mr. Milligan holds a Bachelor of Arts degree from Bowdoin College and a Master's 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.

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Sally A. Sarsfield - Ms. Sarsfield was appointed to the board of directors of our General Partner in February 2015. She currently serves as Chief Financial Officer of Axel Johnson, a position she has held since June 2012. Ms. Sarsfield initially joined Axel Johnson as the VP Finance and Administration in July, 2010. Previously Ms. Sarsfield was the Chief Financial Officer of RA Capital Management, LLC, an investment management firm operating a long/short equity healthcare hedge fund. Prior to that, Ms. Sarsfield was a Partner and Co-Founder of BlueStar Capital Management LP, a firm specializing in healthcare investing via hedge funds where she served as Chief Financial Officer, Partner and Investment Analyst for seven years. Ms. Sarsfield spent the first seven years of her career in a variety of roles with W.R. Grace & Co. including Senior Financial Analyst, Project Manager, Business Development and Director of Financial Planning and Analysis for one of its operating groups. Ms. Sarsfield holds a Bachelor of Arts in Biology from the University of Virginia. She spent a year in the University of Chicago Division of Biological Sciences Ph.D. program in Molecular Genetics before going on to get a Master's in Business Administration from the University of Chicago. We believe the combination of Ms. Sarsfield's years of business and investment management experience, in addition to her expertise in financial oversight, prepare her well to serve on the board of directors of our General Partner.

Ben J. Hennelly - Mr. Hennelly was appointed to the board of directors of our General Partner in July 2011. Mr. Hennelly, currently an independent strategy and finance consultant, served as Chief Financial Officer of Decisyon Inc., an Axel Johnson portfolio company, from September 2012 through December 2014, and as President and Chief Executive Officer from December 2014 through July 2017. Mr. Hennelly previously served as Chief Financial Officer for Axel Johnson during the period of March 2007 through June 2012 and as Executive Vice President for Axel Johnson from June 2012 through December 2014. 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 telecommunication 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 Ph.D from Brown University. We believe that Mr. Hennelly's 20 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, make Mr. Hennelly well-suited to serve on the board of directors of our General Partner.

C. Gregory Harper - Mr. Harper was appointed to the board of directors of our General Partner in October 2013 in connection with our IPO. Mr. Harper retired from Enbridge Inc. in April 2017 where he served as President, Gas Pipelines and Processing and as a principal executive officer of Midcoast Holdings L.L.C. Before joining Enbridge, Mr. Harper served as Senior Vice President of Midstream with 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 is a past director 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, 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 Targa Resources Corp. since March 1, 2016, as a director of Targa Resources GP LLC 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, provide the board of directors of our General Partner with valuable knowledge and skill.

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Beth A. Bowman - Ms. Bowman was appointed to the board of directors of our General Partner in October 2014. Ms. Bowman served at Shell Energy North America for 17 years where she was the Senior Vice President of Sales and Origination North America, until her retirement in September 2015. Prior to joining Shell, Ms. Bowman held management positions at Sempra Energy Trading and Sempra's San Diego Gas & Electric utility. In 2014, Ms. Bowman was named one of the Top 50 Most Powerful Women in Oil and Gas in the U.S. by the National Diversity Council. Ms. Bowman served on the boards of the California Power Exchange and the California Foundation of Energy and Environment. Ms. Bowman received her Bachelor's degree in Science Civil Engineering from the University of Illinois, a Master's degree in Civil Engineering from San Diego State University and a Master's degree in Business Administration Finance from University of San Diego. We believe that Ms. Bowman's extensive energy industry background, particularly her experience in senior leadership roles and board positions of other energy companies, provide the board of directors of our General Partner with valuable knowledge and skill.
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. He also serves as Chairman of the Board for Kildair Service ULC, a Canadian subsidiary of the Partnership. 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.

John W. Moore - Mr. Moore was appointed Vice President, Chief Accounting Officer 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 Energy 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.
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.

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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, with responsibility for leading acquisition sourcing and integration efforts in addition to overseeing our 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 was 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 and his Bachelor’s degree, cum laude, in Political Science and English from Washington and Jefferson College.

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 with a Bachelor of Arts degree in Economics and from the University of Southern New Hampshire with a Master’s degree in Business Administration.

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.

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.

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.

Gillian H. Tierney - Ms. Tierney became the Vice President of Human Resources in May of 2017. Prior to joining Sprague, Ms. Tierney was the Vice President of Human Resources at Newmarket International, a hospitality software company. Ms. Tierney also served as the Director of Human Resources for Bottomline Technologies, a payment and invoice automation software company and as the Director of Human Resources at Tecnomatix Technologies, a manufacturing process management software company. Ms. Tierney spent her early career working in higher education in the career development field, and holds a Bachelor of Arts from the University of New Hampshire, a Master's degree in Education from the University of Massachusetts, a Senior Human Resource Professional certification and is a Senior Certified Professional from the Society of Human Resource Management.

Director Independence

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 Ms. Bowman and Messrs. Evans and Harper meet the independence standards established by the NYSE.

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. Ms. Bowman and Messrs. Evans and Harper are members of the audit committee and the conflicts committee.

Audit Committee

We are required to have an audit committee of at least three members and all its members are required to meet the independence and experience standards established by the NYSE and the Exchange Act. Ms. Bowman and Messrs. Evans and Harper are the current members of our audit committee. 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 met seven times during 2017.

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Conflicts Committee

The board of directors of our General Partner established a conflicts committee to review specific matters that the board of directors 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. The committee consists 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. Ms. Bowman and Messrs. Harper and Evans are the 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. The conflicts committee did not meet during fiscal year 2017.

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 the “Investor Relations—Corporate Governance” section of our website at http://investors.spragueenergy.com/corporate-governance and in print without charge to any unitholder 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 the above referenced Corporate Governance location on our website.

Procedures for Review, Approval and Ratification of Related Person Transactions

Under our Corporate Code of Business Conduct and Ethics, 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. Our Code of Business Conduct and Ethics and Partnership Agreement set forth policies and procedures with respect to transactions with related persons and potential conflicts of interest which, when taken together, provide a structure for the review and approval of transactions with related persons. 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, management will make all reasonable efforts to cancel or annul the transaction.

The conflicts committee is authorized to review, evaluate and approve any potential conflicts of interest between Sprague Resources GP LLC and its affiliates, on one hand, and the Partnership, its subsidiaries, or any General Partner or limited partner of the Partnership, on the other hand; and, the conflicts committee may engage consultants, attorneys, independent accountants and/or other service providers to assist in the evaluation of quantitative and/or qualitative material conflicts matters. Any such approval by the conflicts committee will constitute approval of such matter and no other action of the board of directors is required.

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 may 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 immediate 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 Corporate Code of Business Conduct and Ethics.

Current conflicts committee members include Messrs. Evans and Harper and Ms. Bowman and these three members qualify as independent directors, satisfying the SEC and NYSE standards for independence as of the date herein.

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Available Information

Our Audit Committee charter, Conflicts 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 Whistleblower Policy are available, free of charge within the “Investor Relations—Corporate Governance” section of our website at http://investors.spragueenergy.com/corporate-governance and in print to any unitholder who so requests. 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 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.

Pursuant to our Corporate Governance Guidelines, Mr. Milligan is the lead, non-management director and will preside over regularly scheduled executive sessions of the board of directors without management (“Lead Director”). To view the designated Lead Director and the method for communicating directly with the Lead Director, please see the “Investor Relations—Corporate Governance” section of our website at http://investors.spragueenergy.com/corporate-governance.

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, 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, 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 with respect to our most recent fiscal year, except that Sprague Holdings failed to timely report on Form 4 the conversion of subordinated units held by Sprague Holdings into common units on February 16, 2017.

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Item 11. Executive Compensation

Compensation Committee Report

Neither we nor our General Partner has a compensation committee. The non-management members of our board of directors of our General Partner, listed below, reviewed and discussed with management the section of this report entitled "Compensation Discussion and Analysis" and based on that review and discussion, approved its inclusion herein.

THE NON-MANAGEMENT MEMBERS
OF THE BOARD OF DIRECTORS
Michael D. Milligan, Chairman
Beth A. Bowman
Robert Evans
C. Gregory Harper
Ben J. Hennelly
Sally A. Sarsfield

Compensation Discussion and Analysis

Introduction

Our General Partner has sole responsibility for conducting our business and for managing our operations and its board of directors and officers make decisions on our behalf. 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. The board of directors of our General Partner has 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 2017, referred to in this report as the "Named Executive Officers," and to discuss why and how the 2017 compensation package for these executives was implemented. Disclosure regarding our Named Executive Officers' compensation for the 2017 fiscal year 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, 2017 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
Brian W. Weego	Vice President, Natural Gas

Objectives of Our Executive Compensation Program

Our executive compensation program is 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 achieve or exceed our financial and business goals.
- Incentive compensation should align the interests of the executive team with those of the unitholders.

The board of directors believes these objectives are best met by providing a mix of competitive base salaries in combination with short- and long-term incentive 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.

Setting Executive Compensation

The board of directors has the responsibility and authority to make all decisions with regard to the compensation of our Named Executive Officers. When reviewing the elements of our executive compensation program and making compensation decisions, the board of directors uses the tools and resources described below.

Compensation Consultant

The board of directors engaged Meridian Compensation Partners LLC ("Meridian") as an independent compensation consultant to assist with the redesign of our compensation programs and practices following our initial public offering. We successfully implemented the new compensation programs that Meridian assisted us in designing in 2014. In 2017, the services provided by Meridian to our board of directors were limited to (i) evaluation of total unitholder return and relative total unitholder return for the periods covered by our previously granted performance-based phantom units; and, (ii) with regard to incentive compensation, verifying the average Sprague Resources unit price for the last 20 trading days in December 2017. Throughout their engagement, Meridian has always reported directly and exclusively to the board of directors; however, at the direction of the board of directors they occasionally work directly with management to obtain information and prepare materials for the board of directors' consideration. Meridian does not provide any other services to us or our General Partner. The board of directors determined that Meridian's work did not raise any conflict of interest.

Role of Chief Executive Officer and Other Executive Officers in Determining Executive Compensation

When making determinations about each element of compensation for our Named Executive Officers, other than Mr. Glendon, our board of directors requests and carefully considers recommendations from Mr. Glendon. The board of directors may also ask Mr. Glendon and certain of our other executives to assess the design of, and make recommendations regarding, compensation and benefit programs and the performance measures and targeted levels of performance established thereunder. The board of directors is under no obligation to implement the recommendations received from these executives but may take them into consideration when making compensation decisions.

Components of Compensation

For the fiscal year ending December 31, 2017, the compensation for our Named Executive Officers consisted of the following elements:

- Base salary;
- Annual cash incentive bonus;
- Long-term equity incentive awards; and,
- Other benefits, including retirement, health and welfare, and related benefits and, in certain instances, the use of a car or a car allowance.

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 the Named Executive Officers were historically set at levels deemed appropriate to retain their services. When establishing and evaluating base salary levels the board of directors generally considers the responsibilities associated with each Named Executive Officer's position, experience, skill, education, and potential to contribute to our overall success. For example, when the board of directors evaluates Mr. Glendon's role as President and Chief Executive Officer, the board of directors considers his current and prior performance. In establishing the base salaries for the rest of our Named Executive Officers, the board of directors also considers the extent to which the particular individual has the skills to help us solve the challenges we face and the expertise to help us meet our future business goals. Finally, the board of directors considers the other employment opportunities available to the executive and earning potential associated with those opportunities.

Base salaries for each Named Executive Officer are reviewed annually by the board of directors as well as at the time of any promotion or significant change in job responsibilities. In connection with each review, individual and company performance over the course of the year are also considered. Mr. Glendon makes recommendations with regard to base salary levels for our Named Executive Officers other than himself, and the board of directors takes these recommendations into account when reviewing base salary levels.

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In 2017, following a review of base salary levels for each Named Executive Officer other than himself, Mr. Glendon recommended, and the board of directors approved modest increases in the base salaries of Messrs. Rinaldi, Flaherty, Scammon, and Weego. The board of directors chose to increase the base salaries for each of our Named Executive Officers. 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 increases in the cost of living. The 2017 increases below became effective on April 3, 2017.

Name	2016 Base Salaries	2017 Base Salaries	Percentage Increase
David C. Glendon	$358,750	$365,925	2.0%
Gary A. Rinaldi	$358,750	$365,925	2.0%
Thomas F. Flaherty	$263,398	$268,666	2.0%
Steven D. Scammon	$276,092	$280,233	1.5%
Brian W. Weego	$250,467	$257,981	3.0%

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.

Annual Incentive Bonus

While base salaries offer an important retention tool by providing a fixed level of compensation to our employees, we also 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 a discretionary annual incentive bonus. Further, we feel that our industry has historically relied heavily on performance-based bonuses to compensate executive officers, and we want our compensation program to be consistent with industry trends and practices.

The annual incentive bonus program is administered under the Sprague Resources LP 2013 Long-Term Incentive Plan (which we refer to as our LTIP). Each year our board of directors establishes one or more metrics for the annual incentive bonus. Our performance with respect to the applicable metric for that year determines the level of funding of our annual incentive bonus pool. The annual incentive bonus is paid in cash, and, depending on the level of performance attainment with respect to the applicable performance goals and in the discretion of the board of directors, a portion of the annual incentive bonus may be paid in common units to further align the interests of our Named Executive Officers with those of the unitholders.

The annual incentive bonus received by each Named Executive Officer is initially calculated based on the percentage funding level for the total bonus pool. For example, if the bonus pool for the year was funded based on our performance at a level equal to 120% of the sum of all participants' target bonuses, then the starting place for each Named Executive Officer's annual incentive bonus determination would be 120% of their target bonus. Mr. Glendon may then recommend a higher or lower annual incentive bonus based on each Named Executive Officer's personal performance as well as the performance of their respective business for that year. Mr. Glendon submits his recommendations to the board of directors, who then review and discuss the recommendations. After weighing all of this information, the board of directors establishes the final annual incentive bonus amounts for each Named Executive Officer. Once this determination is made, the board of directors determines what portion of the annual incentive bonus paid to each of the Named Executive Officers will be delivered in cash and what portion, if any, will be delivered in our common units. Generally, any portion of the annual incentive bonus delivered in common units to the Named Executive Officers is fully vested at the time of grant, subject to any holding requirements or restrictions, as determined by the board of directors in its discretion.

Annual incentive bonus targets for our Named Executive Officers generally remain constant from one year to the next and are typically only modified in connection with a significant promotion. When setting annual incentive bonus targets for the Named Executive Officers, the board of directors considers 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 Weego are each set at 50% of their base salary, which is consistent with other employees serving at the Vice President level. The targets for Messrs. Glendon and Rinaldi are set at 100% of their base salary in order to reflect the additional responsibilities associated with their respective positions.

Our board of directors selected distributable cash flow as the performance metric for the 2017 annual incentive bonus program, as such metric demonstrates the Partnership's ability to deliver on its growth plan and generate continued distribution increases. Distributable cash flow is a non-GAAP measure; and, for Named Executive Officer annual incentive compensation purposes, we define distributable cash flow as net income (loss) before interest, income taxes, depreciation and amortization

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adjusted for unrealized hedging losses and gains, in each case with respect to refined products and natural gas inventory, prepaid forward contracts and natural gas transportation contracts, and increased by incentive compensation expense expected to be settled with the issuance of our common units, expenses related to business combinations and other adjustments. Additionally, for annual incentive compensation calculation purposes, there is an allocation of overhead charges and other minor adjustments made to the total distributable cash flow.

The board established a minimum distributable cash flow threshold of $51.4 million for the 2017 annual incentive bonus pool that had to be met before the pool started to fund. Once the distributable cash flow threshold is met, 25% of distributable cash flow is allocated to the bonus pool until the bonus pool is funded at a level equal to 200% of the target bonus pool amount. After the bonus pool is funded at 200% of the target bonus pool amount, 10% of the additional distributable cash flow above that level, if any, is allocated to the annual incentive bonus pool. For 2017, actual distributable cash flow for annual incentive compensation purposes was $72.7 million. As a result, the annual incentive bonus pool was funded in an amount equal to 90% of the target bonus level for all participants. Given this funding level, the board of directors determined that the 2017 annual incentive bonuses would be paid solely in cash, rather than a combination of cash and common units.

The cash amounts reflected in the table below are included in the “Bonus” column of the Summary Compensation Table. For 2017, the board of directors awarded the following annual cash incentive bonuses to the Named Executive Officers:

Name	2017 Annual Incentive Bonus Cash
David C. Glendon	$310,000
Gary A. Rinaldi	$310,000
Thomas F. Flaherty	$115,000
Steven D. Scammon	$110,000
Brian W. Weego	$115,000

Long-Term Equity Incentive Awards

In October 2013, our General Partner adopted the LTIP, which provides us with the flexibility to grant a wide variety of cash and equity or equity-based awards. In March 2016, our board of directors decided to grant unit-settled performance-based phantom units that vest based on earnings before interest, tax, depreciation and amortization at Sprague Holdings reduced by interest expense and capital expenditures at ("Sprague Holdings Operating Cash Flow" or "Sprague Holdings OCF") over a three-year performance period. Sprague Holdings does not generate audited financial statements but is included in the audited financial statements of our Sponsor, Axel Johnson.

In March 2017, our board of directors again determined to award unit-settled performance-based phantom units utilizing the Sprague Holdings OCF performance metric. The board determined that calculating the performance metric at Sprague Holdings will reflect the fact that the General Partner manages assets owned by Axel Johnson that were not contributed to the Partnership. The Board believes that this compensation structure avoids the possibility of misaligned peer groupings and that the incentive compensation reflects the General Partner's total management activity. A majority of the assets at Sprague Holdings were formerly held by our Predecessor and consist of one operating terminal and one terminal that is not in operation, both of which were similar in nature to assets currently held by the Partnership. Accordingly, the board of directors believes that there is a high correlation of performance between Sprague Holdings and the Partnership.

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Under the 2017 long-term equity incentive program, Sprague Holdings OCF is measured over a performance period from January 1, 2017 through December 31, 2019. Sprague Holdings OCF of $180.7 million must be met before any of the phantom units granted in 2017 vest. The table below shows the rate of increase in Sprague Holdings OCF above the $180.7 million threshold amount and the corresponding vesting level of the 2017 phantom units.

Increase of Sprague Holdings Operating Cash Flow Above Threshold	Percentage of Target Phantom Units that Vest
0.0%	0%
5.1%	50%
10.3%	100%
42.2%	200%

If the growth of Sprague Holdings Operating Cash Flow for the performance period falls between the percentiles enumerated above, then the number of phantom units that vest will be calculated using straight line interpolation.

In March 2017, the board of directors granted a target number of the phantom unit awards described above, having a grant date fair value of $26.60 per unit, to each of our Named Executive Officers as follows:

Name	2017 Long-Term Incentive Program Target Number of Phantom Units Granted	Grant Date Fair Value per Common Unit (1)
David C. Glendon	18,900	$26.60
Gary A. Rinaldi	18,900	$26.60
Thomas F. Flaherty	5,000	$26.60
Steven D. Scammon	4,750	$26.60
Brian W. Weego	5,000	$26.60

(1) The value of the phantom performance awards is based on the grant date fair value of those common units, as calculated pursuant to FASB ASC Topic 718.

Phantom units that vest will be settled within 30 days of the end of the performance period. These awards also include a tandem distribution equivalent right that will be paid upon the settlement of the underlying phantom unit. There are no resale restrictions on common units delivered upon settlement of the phantom unit awards.

In March 2018, our board of directors determined that the 2018 long-term equity program would be structured in a manner similar to the 2017 program. In accordance with the SEC's rules and regulations, the 2018 long-term equity incentive program will be discussed in detail in our Annual Report on Form 10-K for the year ended December 31, 2018.

Severance and Change in Control Benefits

The Named Executive Officers did not have agreements with us that contained severance provisions or change of control payment provisions during the 2017 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 enter into 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 continued base salary payments, (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.

Our form of award agreement for performance-based phantom units provides for prorated vesting at the end of the performance period based on the actual performance level achieved if the grantee ceases to provide services to us and our affiliates before the end of the applicable performance period as a result of: (i) a qualifying retirement, (ii) death, or (iii) disability. We believe that these terms allow the grantee or his or her family, as the case may be, to receive an equitable portion of the award earned based on actual performance upon a termination of service due to these limited circumstances.

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We believe that the severance practices described above create an important retention tool for us as post-termination payments allow employees to leave our employment with value in the event of certain terminations of employment that are 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 best 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.

Other Benefits

Health and Welfare Benefits

All of our regular full-time employees, including our Named Executive Officers, receive the same health and welfare benefits. These 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

During 2017, we provided all employees hired prior to January 1, 1991 who were scheduled to work at least 30 hours per week and 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 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 pay 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 is intended to help those employees with a shorter earnings horizon, as they had less time to adjust their financial retirement planning following our decision to freeze the DB Plan. Full-time employees or part-time employees 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.

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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 such employee to properly perform his or her job duties. 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 2017, Mr. Flaherty was the only Named Executive Officer eligible to receive this benefit.

Risk Assessment

The board of directors 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 associated with such policies 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 evaluate the effectiveness of our compensation programs, by analyzing the incentives such programs create and considering how we can minimize or eliminate incentives that may create risk for us.

Our 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.
- Our compensation mix is balanced among fixed components like salary and benefits, as well as annual incentives that reward overall company and individual performance.
- Our long-term equity incentive program ties vesting to performance over a period of multiple years with common units paid out at the end of the applicable performance period if the pre-established goals are met. These programs were designed to encourage executives to focus on unitholder interests over the longer term. In contrast, the annual incentive bonus focuses on performance over the shorter term. The combination of both programs appropriately focuses our employees on both our short- and long-term performance.
- The board of directors of our General Partner has retained an appropriate level of discretion to reduce annual incentive bonus payments if it determines that such adjustments would be appropriate based on our interests and the interests of our unitholders.

Although a significant portion of the compensation provided to our Named Executive Officers is performance-based, we believe our compensation programs do not encourage excessive and unnecessary risk taking by the executive officers (or other employees) as 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 to our Named Executive Officers is comprised of awards that are subject to non-payment if the organization does not achieve a threshold level of distributable cash flow and Sprague Holdings Operating Cash Flow. As such, we believe that executives are less likely to take unreasonable risks. Once threshold levels of performance are achieved, our performance-based incentives provide payouts of compensation at levels below full performance target achievement, in lieu of an “all or nothing” approach.

Additionally, we have a Chief Risk Officer who serves as chair of the Risk Management Committee, comprised of several members of management and representatives of Sprague Holdings. The Risk Management Committee is responsible for reviewing 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 of directors and has the authority to review all aspects of our business and to develop and maintain policies and procedures that discourage employees from taking unnecessary or inappropriate risks.

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Summary Compensation Table

The table below summarizes the total compensation earned by or paid to our Named Executive Officers during the last three fiscal years.

Name and Title	Year	Salary ($)(1)	Bonus ($) (2)	Stock Awards ($)(3)	Change in Pension Value Non-Qualified Deferred Compensation Earnings ($)(4)(5)	All Other Compensation ($)(6)	Total ($)
David C. Glendon	2017	363,993	310,000	502,740	N/A	23,220	1,199,953
President and Chief Executive Officer	2016	356,394	495,650	511,890	N/A	22,790	1,386,724
	2015	350,000	655,000	1,231,555	N/A	21,004	2,257,559
Gary A. Rinaldi	2017	363,993	310,000	502,740	N/A	23,220	1,199,953
Senior Vice President, Chief Operating	2016	356,394	495,650	511,890	N/A	22,790	1,386,724
Officer and Chief Financial Officer	2015	350,000	655,000	1,231,555	N/A	22,890	2,259,445
Thomas F. Flaherty	2017	267,248	115,000	133,000	89,002	48,720	652,970
Vice President, Refined Products	2016	262,008	175,325	163,965	50,462	48,540	700,300
	2015	256,968	233,676	375,611	—	48,040	914,295
Steven D. Scammon	2017	279,118	110,000	126,350	13,621	23,220	552,309
Vice President, Chief Risk Officer	2016	275,356	192,701	117,931	7,037	22,790	615,815
	2015	272,682	240,019	355,374	—	22,594	890,669
Brian W. Weego	2017	255,958	115,000	133,000	13,172	22,179	539,309
Vice President, Natural Gas	2016	247,874	175,325	155,205	6,228	21,834	606,466

(1) Amounts in this column reflect all compensation earned by the Named Executive Officers during the fiscal year as base salary. Prior to April 3, 2017, the base salaries for our Named Executive Officers were $358,750 for Messrs. Glendon and Rinaldi, $263,398 for Mr. Flaherty, $276,092 for Mr. Scammon, and $250,467 for Mr. Weego. Effective April 3, 2017, the base salaries for our Named Executive Officers were as follows: $365,925 for Messrs. Glendon and Rinaldi, $268,666 for Mr. Flaherty, $280,233 for Mr. Scammon, and $257,981 for Mr. Weego.

(2) Amounts in this column for 2017 reflect cash amounts paid under our annual incentive bonus program, as determined by the board of directors.

(3) Amounts in this column for 2017 reflect the grant date fair value for the performance based phantom awards computed in accordance with FASB ASC Topic 718, disregarding estimated forfeitures, which was $26.60 per common unit. The values of the performance-based phantom units at the grant date assuming that the highest level of performance conditions will be achieved for our Named Executive Officers are as follows: $1,005,480 for Messrs. Glendon and Rinaldi, $266,000 for Messrs. Flaherty and Weego, and $252,700 for Mr. Scammon.

(4) Amounts in this column represent the actuarial increase, if any, in the present value of benefits under the DB Plan and the RRP determined by using interest rate and mortality rate assumptions consistent with those used in the Pension Benefits table below. Messrs. Glendon and Rinaldi do not participate in these plans. Negative values are not reported in this column and are instead indicated by use of a dash.

(5) For fiscal year 2015, there were aggregate losses of $9,629 for Mr. Flaherty and $2,953 for Mr. Scammon.

(6) The amounts set forth in this column for 2017 represent: (i) 401(k) plan matching contributions; (ii) our contribution to the DC Plan; (iii) Named Executive Officer car allowance; and, (iv) other incidental payments. 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. For a quantification of these benefits please see the table below. For more information regarding these benefits, please see the "Other Benefits" section of our Compensation Discussion and Analysis above.

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Recipient	401(k) Plan Matching Contribution ($)	Defined Contribution Plan ($)	Car Allowance ($)	Other Incidental ($)	All Other Compensation Total ($)
David C. Glendon	9,720	13,500	—	—	23,220
Gary A. Rinaldi	9,720	13,500	—	—	23,220
Thomas F. Flaherty	9,720	27,000	12,000	—	48,720
Steven D. Scammon	9,720	13,500	—	—	23,220
Brian W. Weego	8,679	13,500	—	—	22,179

Grants of Plan-Based Awards

The Grants of Plan-Based Awards Table sets forth information regarding the performance-based phantom units granted in March 2017. These equity-based awards were granted pursuant to our LTIP and remain subject to its terms. More information regarding the terms of these awards is provided in the “Components of Compensation—Long-Term Equity Incentive Awards” section of our Compensation Discussion and Analysis above.

Name	Grant Date	Estimated Future Payouts Under Equity Incentive Plan Awards (1)			All Other Stock Awards: Number of Shares of Stock or Units (#)	Grant Date Fair Value of Stock and Option Awards ($)(2)
		Threshold (#)	Target (#)	Maximum (#)		
David C. Glendon	3/6/2017	—	18,900	37,800	—	502,740
Gary A. Rinaldi	3/6/2017	—	18,900	37,800	—	502,740
Thomas F. Flaherty	3/6/2017	—	5,000	10,000	—	133,000
Steven D. Scammon	3/6/2017	—	4,750	9,500	—	126,350
Brian W. Weego	3/6/2017	—	5,000	10,000	—	133,000

(1) Amounts shown in the “Estimated Future Payouts Under Equity Incentive Plan Awards” columns represent the target and maximum settlement levels with respect to the performance-based phantom unit awards granted to our Named Executive Officers pursuant to our LTIP during 2017. The performance-based phantom unit awards do not have a threshold value. Vesting of the phantom units will be determined based on Sprague Holdings Operating Cash Flow performance during the performance period from January 1, 2017 through December 31, 2019. The performance-based phantom unit awards include a distribution equivalent right, which will be paid upon the settlement of the underlying phantom unit. For more information regarding the performance-based phantom unit awards, please see the “Components of Compensation—Long-Term Equity Incentive Awards” section of our Compensation Discussion and Analysis above.

(2) The amounts in this column reflect the aggregate grant date fair value of awards granted to our Named Executive Officers in 2017 computed in accordance with FASB ASC Topic 718, disregarding estimated forfeitures. The grant date fair value of the phantom units issued pursuant to our long term equity incentive program was $26.60 per phantom unit. For a discussion of the valuation assumptions used in determining the grant date fair value of these awards see Note 19. “Equity-Based Compensation” of the Notes to Consolidated Financial Statements included in this Annual Report.

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Outstanding Equity Awards at Fiscal Year-End

The following table reflects the total number and estimated value of outstanding performance based phantom units held by our Named Executive Officers as of December 31, 2017.

Name	Stock Awards Number of Shares or Units of Stock That Have Not Vested (#)	Market Value of Shares or Units of Stock That Have Not Vested ($)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or other Rights That Have Not Vested (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or other Rights That Have Not Vested ($)(1)
David C. Glendon	—			
			24,500 (2)	592,900
			18,900 (3)	457,380
Gary A. Rinaldi	—			
			24,500 (2)	592,900
			18,900 (3)	457,380
Thomas F. Flaherty	—			
			7,000 (2)	169,400
			5,000 (3)	121,000
Steven D. Scammon	—			
			6,000 (2)	145,200
			4,750 (3)	114,950
Brian W. Weego	—			
			6,500 (2)	157,300
			5,000 (3)	121,000

(1) Amounts represented assume a market value of $24.20 per common unit, the closing price of our common units on December 29, 2017.

(2) Because these awards do not have a threshold value, these figures represent the target settlement level with respect to the performance-based phantom unit awards granted to our Named Executive Officers pursuant to our LTIP on March 7, 2016 based on our performance through December 31, 2017 as required by the Exchange Act. The number of phantom units that will ultimately vest will depend on our performance through the end of the three-year performance period ending December 31, 2018. These awards contain cash distribution equivalent rights that are paid out to the phantom unit holders at the time of settlement of the underlying phantom unit in the same form (cash or common units) as was delivered to our common unitholders at the time of the distribution. From the date of grant until December 31, 2017, all distributions delivered to common unitholders have been paid in cash.

(3) Because these awards do not have a threshold value, these figures represent the target settlement level with respect to the performance-based phantom unit awards granted to our Named Executive Officers pursuant to our LTIP on March 6, 2017 based on our performance through December 31, 2017 as required by the Exchange Act. The number of phantom units that will ultimately vest will depend on our performance through the end of the three-year performance period ending December 31, 2019. These awards contain cash distribution equivalent rights that are paid out to the phantom unit holders at the time of settlement of the underlying phantom unit in the same form (cash or common units) as was delivered to our common unitholders at the time of the distribution. From the date of grant until December 31, 2017, all distributions delivered to common unitholders have been paid in cash.

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Option Exercises and Stock Vested

The following table reflects the total number of time-based and performance-based phantom units held by our Named Executive Officers that vested during 2017. We have not granted any stock options or stock appreciation rights under our LTIP or otherwise.

Name	Stock Awards Number of Shares Acquired on Vesting (#)	Value Realized on Vesting ($)(1)(2)
David C. Glendon	74,431	1,897,830
Gary A. Rinaldi	74,431	1,897,830
Thomas F. Flaherty	18,730	477,416
Steven D. Scammon	18,730	477,416
Brian W. Weego	18,730	477,416

(1) The amounts reflected in this column represent the aggregate market value realized by each Named Executive Officer on the vesting date of the time-based or performance-based phantom units held by such Named Executive Officer. The value realized upon vesting was determined by multiplying the number of units by the closing market price of the underlying units on the day prior to the applicable vesting date. The closing price of our common units on January 27, 2017 and December 29, 2017 was $27.65 and $24.20, respectively. The value realized upon vesting is comprised of the gross number of common units that vested and has not been reduced to take into account any common units net withheld to pay taxes.

(2) Value realized on vesting was computed as described in footnote (1) above and was based on the following:

Recipient	Date of Award	Vesting Date	Number of Shares Vested (#)	Market Price on Vesting Date ($)	Value Realized on Vesting ($)
David C. Glendon	7/11/2014	1/30/2017	28,000	27.65	774,200
	3/5/2015	12/31/2017	46,431	24.20	1,123,630
Gary A. Rinaldi	7/11/2014	1/30/2017	28,000	27.65	774,200
	3/5/2015	12/31/2017	46,431	24.20	1,123,630
Thomas F. Flaherty	7/11/2014	1/30/2017	7,000	27.65	193,550
	3/5/2015	12/31/2017	11,730	24.20	283,866
Steven D. Scammon	7/11/2014	1/30/2017	7,000	27.65	193,550
	3/5/2015	12/31/2017	11,730	24.20	283,866
Brian W. Weego	7/11/2014	1/30/2017	7,000	27.65	193,550
	3/5/2015	12/31/2017	11,730	24.20	283,866

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 2017.

Name	Plan Name	Number of Years Credited Service (#)(1)(2)	Present Value of Accumulated Benefit ($)(3)	Payments During 2017 Fiscal Year ($)
David C. Glendon	Axel Johnson Inc. Retirement Plan	—	—	—
	Axel Johnson Inc. Retirement Restoration Plan	—	—	—
Gary A. Rinaldi	Axel Johnson Inc. Retirement Plan	—	—	—
	Axel Johnson Inc. Retirement Restoration Plan	—	—	—
Thomas F. Flaherty	Axel Johnson Inc. Retirement Plan	20.4	834,350	—
	Axel Johnson Inc. Retirement Restoration Plan	20.4	214,158	—
Steven D. Scammon	Axel Johnson Inc. Retirement Plan	3.0	97,165	—
	Axel Johnson Inc. Retirement Restoration Plan	3.0	27,102	—
Brian W. Weego	Axel Johnson Inc. Retirement Plan	5.0	96,797	—
	Axel Johnson Inc. Retirement 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 as they were hired after January 1, 2003.

(3) Amounts in this column represent the actuarial present value of each Named Executive Officer's accumulated benefit under the DB Plan and the RRP as of December 31, 2017. 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 3.70% for the Axel Johnson Inc. Retirement Plan and the Axel Johnson Inc. Retirement Restoration Plan; (ii) the RP-2014 annuitant table and the MP-2017 mortality improvement scale applied from the RP-2014 mortality table base year; and, (iii) expected long-term rate of return on plan assets of 6.00%.

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 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 years, rounded to the	40	+	0.4% of final average compensation in excess of social	x	Credited service

nearest month)	security covered compensation	(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

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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, 2017, under the DB Plan, Mr. Flaherty was 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 2017 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 execute 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 payments historically provided to executives, such as the Named Executive Officers, serving at the Vice President level and above, consist of the following: (i) 12 months of continued base salary severance, (ii) 6 months of outplacement support; and, (iii) health and dental insurance for 12 months provided at the same cost as such individual paid during his or her employment with us.

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The table below represents an estimate, based on the assumptions provided herein, of the amounts that each of the Named Executive Officers would have received in the event of a separation from service for the reasons set forth below, in both cases with the stated event occurring on December 31, 2017.

Name	Cash Severance ($)(1)	Outplacement Support ($)(2)	Health and Dental ($)(3)	Accelerated Equity ($)(4)	Total Potential Termination Benefits ($)
David C. Glendon					
Termination Without Cause	365,925	6,000	20,916	—	392,841
Retirement, Death, Disability	—	—	—	190,575	190,575
Gary A. Rinaldi					
Termination Without Cause	365,925	6,000	13,842	—	385,767
Retirement, Death, Disability	—	—	—	190,575	190,575
Thomas F. Flaherty					
Termination Without Cause	268,666	6,000	15,684	—	290,350
Retirement, Death, Disability	—	—	—	50,417	50,417
Steven D. Scammon					
Termination Without Cause	280,233	6,000	18,487	—	304,720
Retirement, Death, Disability	—	—	—	47,896	47,896
Brian W. Weego					
Termination Without Cause	257,981	6,000	18,487	—	282,468
Retirement, Death, Disability	—	—	—	50,417	50,417

(1) Amounts in this column reflect 12 months' worth of continued base salary severance based on each Named Executive Officer's base salary in effect as of December 31, 2017.

(2) Amounts in this column reflect the estimated cost to us of providing outplacement services to the Named Executive Officers over a six-month period. The actual cost of such services could vary based on the individual needs of each Named Executive Officer and the outside provider of such services.

(3) Amounts in this column reflect the value of continued health and dental benefits for a 12-month period based on the value of the benefits received by each individual as of December 31, 2017.

(4) A prorated portion of the performance-based phantom units granted in each 2016 and 2017 will remain outstanding and eligible to vest based on actual performance, as determined following the end of the applicable performance period, in the event of a Named Executive Officer's separation from service due to a qualified retirement, death or Disability (as described below) prior to the completion of the applicable performance period. The performance periods applicable to the 2016 and 2017 awards will end on December 31, 2018 and December 31, 2019, respectively, and the number of phantom units that vest for each award will be based on performance through the last day of the applicable performance period. Based upon the performance metrics applicable to the 2016 phantom unit awards and using our performance through December 31, 2017, it is estimated that no portion of the phantom units granted in 2016 would have vested following the end of the performance period, and accordingly no pro rata portion would become vested in connection with any of our Named Executive Officers' retirement or termination due to death or Disability on December 31, 2017. Actual payment under the 2016 phantom unit awards, assuming maximum performance, could total up to $1,185,800 for each of Messrs. Glendon and Rinaldi, $338,800 for Mr. Flaherty, $290,400 for Mr. Scammon, and $314,600 for Mr. Weego, calculated using the closing price of our common units on December 29, 2017, which was $24.20. Based upon the performance metrics applicable to the 2017 phantom unit awards and using our performance through December 31, 2017, it is estimated that the phantom units granted in 2017 will vest at the 125% performance level following the end of the performance period. As such, the prorated amount our Named Executive Officers would be eligible to receive following the end of the performance period in connection with their retirement or termination due to death or Disability on December 31, 2017 is shown in this column. Actual payment under the 2017 phantom unit awards assuming maximum

performance could total up to $914,760 for Messrs. Glendon and Rinaldi, $242,000 each for Messrs. Flaherty and Weego, and $229,900 for Mr. Scammon, calculated using the closing price of our common units on December 29, 2017, which was $24.20.

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The Named Executive Officers are not entitled to any payments or benefits upon a change in control of us. However, the LTIP provides that on the occurrence of a “Change of Control” (as defined below), the board of directors, acting in its sole discretion without the consent or approval of any grantee, may, among other things, remove any applicable forfeiture restrictions on any award under the LTIP and accelerate the time at which the restricted period shall lapse to a specific date before or after such Change of Control.

The LTIP provides that “Change of Control” means one or more of the following events: (i) any “person” or “group” within the meaning of those terms as used in Sections 13(d) and 14(d)(2) of the Exchange Act, other than members of the General Partner, the Partnership, or an affiliate of either the General Partner or the Partnership, becomes the beneficial owner, by way of merger, consolidation, recapitalization, reorganization or otherwise, of 50% or more of the voting power of the voting securities of the General Partner or us; (ii) the limited partners of the General Partner or of us approve, in one transaction or a series of transactions, a plan of complete liquidation of the General Partner or us; (iii) the sale or other disposition by either the General Partner or us of all or substantially all of its assets in one or more transactions to any person other than an affiliate; (iv) the General Partner or an affiliate of the General Partner or us ceases to be our General Partner; or (v) any other event specified as a “Change of Control” in an applicable award agreement. Notwithstanding the above, with respect to an award that is subject to Section 409A of the Internal Revenue Code of 1986, a “Change of Control” will not occur unless that Change of Control also constitutes a “change in the ownership of a corporation,” a “change in the effective control of a corporation,” or a “change in the ownership of a substantial portion of a corporation’s assets,” in each case, within the meaning of 1.409A-3(i)(5) of the Treasury Regulations, as applied to non-corporate entities.

For the performance-based phantom units granted in 2016 and 2017, the applicable award agreements provide that in the event the Named Executive Officer ceases to provide services to us, our General Partner, or our respective affiliates before the end of the applicable performance period by reason of: (i) the Named Executive Officer’s retirement (A) on or after having attained age 60, provided that such Named Executive Officer has provided at least ten consecutive years of service as of the date of such retirement, or (B) having attained the age of 65, (ii) death, or (iii) Disability (as defined below), then, in each case, the Named Executive Officer is eligible to receive the number of phantom units he or she would otherwise be entitled to receive under the award agreement based on the actual level of performance attainment determined following the end of the applicable performance period, prorated by the number of days that elapsed in the applicable performance period prior to such cessation of services to us, our General Partner, or our respective affiliates. Other than in the event of a separation from service due to a qualified retirement, death or Disability, the Named Executive Officers must remain employed through the applicable date of vesting of the performance-based phantom unit awards, which coincides with the last day of the applicable performance period, in order to receive delivery of the common units thereunder.

For purposes of these agreements, “Disability” means that the applicable Named Executive Officer becomes eligible to receive long-term disability benefits under our long-term disability plan, or, if the Named Executive Officer does not participate in our long-term disability plan, that he or she is unable to perform the essential functions of his or her position, with reasonable accommodation, due to an illness or physical impairment or other incapacity that continues, or can reasonably be expected to continue, for a period in excess of 180 days, whether or not consecutive. The determination of whether a Named Executive Officer has incurred a Disability under the foregoing shall be made in good faith by the board of directors.

The above descriptions of the phantom unit award agreements and our LTIP do not purport to be complete and are qualified in their entirety by reference to the full text of the phantom unit award agreements and the LTIP, which have been previously filed with the SEC.

CEO Pay Ratio - 18.8:1

Pursuant to Section 953(b) of the Dodd-Frank Act and Item 402(u) of Regulation S-K, this section provides information regarding the relationship of the annual total compensation for fiscal year 2017 of Mr. Glendon, our Chief Executive Officer (“CEO”), to that of our Median Employee (as defined below).

For fiscal year 2017, our CEO’s annual total compensation, as reported in the Summary Compensation Table, was $1,199,953, and our Median Employee’s annual total compensation was $63,662. The ratio of our CEO’s total annual compensation to that of our Median Employee for fiscal year 2017 is 18.8 to 1.

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Determining our Median Employee

In determining our Median Employee, we selected October 1, 2017 as the date on which to identify our total employee population, which includes all employees in the U.S. and Canada. Employees on leave of absence were also included. In identifying our Median Employee, we used the estimated compensation of all of our employees for the nine-month period of January 1, 2017 through September 30, 3017, which included the following items:

i. Estimated wages and salaries based on all payroll payments, excluding group term life; and
ii. Estimated target annual incentive bonus amounts for each employee.

For permanent employees who were not employed for the full nine-month period, their wages and salaries were adjusted to reflect an estimate of such base rates of pay for the full nine-month period. Wages and salaries were not adjusted for seasonal employees. In addition, we applied a Canadian to U.S. dollar exchange rate to the compensation elements paid in Canadian currency.

After calculating each employee’s compensation using this consistently applied methodology, we then ranked all of our employees, excluding the CEO, based on compensation from lowest to highest and selected the median employee (“Median Employee”). After identifying our Median Employee, we then calculated the total annual compensation of our Median Employee in the same manner as the “Total Compensation” shown for our CEO in the Summary Compensation Table above. As our Median Employee was not employed for all of the 2017 fiscal year, we annualized our Median Employee's total annual compensation to provide for a more direct comparison to the total annual compensation of our CEO.

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2017 DIRECTOR COMPENSATION

We use a combination of cash and equity compensation to attract and retain qualified candidates to serve as directors of our General Partner. 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.

Prior to September 2016, officers, employees or paid consultants and advisors of our General Partner or its affiliates (including Axel Johnson Inc. and its affiliates) who served as members of the board of directors of the General Partner did not receive additional compensation for their service as members of the board of directors. In September 2016, in recognition of Mr. Hennelly's service, the board of directors, began to compensate Mr. Hennelly in a manner similar to a non-employee director. Accordingly, effective as of September 2016, each non-employee director and Mr. Hennelly receives an annual retainer of $60,000, paid in quarterly installments. Each non-employee director and Mr. Hennelly also receives an annual equity award, granted within five business days of October 15 of each year, equal to the number of fully vested common units having a grant date fair value of approximately $60,000, subject to the terms and vesting schedules set forth in the applicable grant documents. Further, each non-employee director and Mr. Hennelly serving as a chairman or a member of a committee of the board receives an annual supplemental retainer of $10,000 or $5,000, respectively, paid in quarterly installments. All directors receive reimbursement for out-of-pocket expenses associated with attending meetings of the board or committees of the board of directors. Each director is covered by liability insurance and will be fully indemnified by us for actions associated with being a director to the fullest extent permitted under Delaware law.

Ms. Bowman and Messrs. Evans, Harper and Hennelly received a fully vested annual grant of common units valued at approximately $60,000 in October 2017. The table below summarizes the compensation paid to independent directors and Mr. Hennelly for the fiscal year ended December 31, 2017.

Name (1)	Fees Earned or Paid in Cash ($)(3)	Unit Awards ($)(4)(5)	Total ($)
Robert B. Evans	75,000	60,000	135,000
C. Gregory Harper	75,000	60,000	135,000
Beth A. Bowman	70,000	60,000	130,000
Ben J. Hennelly (2)	60,000	60,000	120,000

(1) Mr. Milligan and Ms. Sarsfield, as officers of Axel Johnson, and Messrs. Glendon and Rinaldi are not included in this table because they receive no separate compensation for their services as directors. The compensation received by Messrs. Glendon and Rinaldi as our Named Executive Officers is shown in the Summary Compensation Table.

(2) Mr. Hennelly, an independent strategy and finance consultant, is a former officer of Axel Johnson and former President and Chief Executive Officer of Decisyon Inc., a portfolio company of Axel Johnson. Effective September 2016, Mr. Hennelly receives separate compensation for his services as a director.

(3) The amounts in this column reflect the aggregate dollar amount of fees earned or paid in cash for fiscal year 2017, including annual retainer fees 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. Ms. Bowman is a member of the Audit Committee and the Conflicts Committee.

(4) Represents the aggregate grant date fair value computed in accordance with FASB ASC Topic 718. Messrs. Evans, Harper and Hennelly and Ms. Bowman all received a fully vested grant of 2,340 units valued at approximately $60,000 in October 2017. Please see Note 19. “Equity-Based Compensation” in the Notes to our Consolidated Financial Statements for assumptions used in valuing our common units.

(5) On December 31, 2017, none of our directors held outstanding, unvested equity awards.

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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 of Sprague Resources LP that are issued and outstanding as of March 6, 2018 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	Common Units Beneficially Owned		Percentage of Common Units Beneficially Owned	
Sprague Holdings LLC (1)(2)	12,106,348		53.3	%
Axel Johnson (2)(3)	12,106,348		53.3	%
Lexa International Corporation (2)(4)	12,106,348		53.3	%
Antonia Ax:son Johnson (2)(5)	12,106,348		53.3	%
OppenheimerFunds, Inc. (6)	1,656,956		7.3	%
Goldman Sachs Asset Management (7)	1,211,016		5.3	%
Carbo Industries, Inc. (8)	1,131,551		5.0	%
Gary A. Rinaldi	110,360		*	
David C. Glendon	110,173		*	
Thomas E. Flaherty	36,662		*	
Brian W. Weego	33,312		*	
Steven D. Scammon	30,046		*	
Michael D. Milligan	20,000		*	
Robert B. Evans	14,271		*	
C. Gregory Harper	14,271		*	
Beth A. Bowman	9,945		*	
Sally A. Sarsfield	4,100		*	
Ben J. Hennelly	2,340		*	
All executive officers and directors of our General Partner as a group (15 persons)	511,139	(9)	2.2	%

* Represents less than 1%.

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

(2) Common units shown as beneficially owned by Axel Johnson, Lexa International Corporation and Antonia Ax:son Johnson reflect common 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 and its subsidiaries, 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,

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Antonia Ax:son Johnson may be deemed to share beneficial ownership of the units beneficially owned by Sprague Holdings, but disclaims such beneficial ownership.
(3) The address for this entity is 155 Spring Street, 6th Floor, New York, NY 10012.
(4) The address for this entity is 2410 Old Ivy Road, Suite 300, Charlottesville, VA 22903.
(5) The address for this person is c/o Axel Johnson AB, Villagatan 6, P.O. Box 26008, SE-100 41 Stockholm, Sweden.
(6) The address for this entity is 225 Liberty Street, New York, NY 10281. OppenheimerFunds, Inc. reported shared voting power and shared dispositive power for 1,656,956 common units that are held in the accounts of investment advisory clients advised by OppenheimerFunds, Inc., directly and through its subsidiaries. Beneficial ownership reported is based solely on a Schedule 13G filed on February 6, 2018.
(7) Goldman Sachs Asset Management, L.P., together with GS Investment Strategies, LLC, reported as "Goldman Sachs Asset Management". The address for Goldman Sachs Asset Management is 200 West Street, New York, NY 10282. Goldman Sachs Asset Management reported shared voting and shared dispositive power with respect to all of the 1,211,016 common units. Beneficial ownership reported based solely on a Schedule 13G filed on January 24, 2018.
(8) The address for this entity is 1 Bay Boulevard, Lawrence, NY 11559. Carbo Industries, Inc. reported sole voting and sole dispositive power for 1,131,551 common units. Beneficial ownership reported is based solely on a Schedule 13G filed on February 9, 2018.
(9) The address of each of the executive officers and directors is 185 International Drive, Portsmouth, NH 03801.

Securities Authorized for Issuance Under Equity Compensation Plans

The following information is reported as of December 31, 2017.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)(1)	Weighted-average exercise price of outstanding options, warrants and rights (b)(2)	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	433,900	—	194,967

(1) Awards in this column represent the total number of all performance-based phantom units granted under our LTIP and outstanding as of December 31, 2017. We have not granted any stock option awards.
(2) The outstanding phantom units do not have an exercise price. As such, there is no weighted average exercise price to report for outstanding awards.

Our only equity compensation plan is the Sprague Resources LP 2013 Long-Term Incentive Plan, also referred to herein as the “LTIP”. The LTIP was approved by our shareholders prior to our initial public offering but has not been approved by our public shareholders. A description of the material terms of the 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 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

Consideration given to Sprague Holdings and its affiliates for the contributions of assets and liabilities to us included the following:

- 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 unitholders, including Sprague Holdings as the holder of an aggregate of 12,106,348 common 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. During the year ended December 31, 2017, Sprague Holdings received $3.2 million related to its incentive distribution rights.

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 $20.0 million on its common 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 $97.3 million for the year ended December 31, 2017.

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.

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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 addresses 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 businesses 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.

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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 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.

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

The Partnership, Sprague Energy Solutions, Inc. (“Sprague Solutions”) and Sprague Holdings entered into a services agreement with our General Partner pursuant to which our General Partner agreed 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 agreed 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 $97.3 million for the year ended December 31, 2017.

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.

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 for five years, beginning on October 30, 2013. 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.

Subsequent to the IPO related agreements described above, we entered into certain agreements with our sponsor and certain of its affiliates, as described below.

Medius Agreement

On September 30, 2016, our General Partner entered into a Master Cloud Subscription Agreement, and other ancillary agreements (collectively, "Medius Agreement"), for financial software product and services with Medius Software Inc., a subsidiary of Medius AB ("Medius"). At the date of the agreement, an affiliate of Axel Johnson, our Sponsor, had a greater than 10% ownership interest in Medius; however, on September 5, 2017, the affiliate of Axel Johnson sold all of its ownership interest in Medius. Under the Medius Agreement, our General Partner made an initial payment of $71,300 and committed to annual subscription and other payments of $85,900 per year for a period of three years. After the initial three-year term, unless terminated by the Partnership, the Medius Agreement will automatically renew for a period of 12 months.

Director Independence

The information required by Item 407(a) of Regulation S-K is included in Item 10 - "Directors, Executive Officers and Corporate Governance" above.

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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, 2017. 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 billed for auditing, tax and related services rendered by Ernst & Young LLP to us for each of the last two fiscal years.

	Fiscal 2017	Fiscal 2016
Audit Fees (1)	$2,710,500	$2,184,700
Audit-Related Fees (2)	12,800	—
Tax Fees (3)	272,200	332,300
All Other Fees	5,000	5,000
Total	$3,000,500	$2,522,000

(1) Audit fees 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) Audit-related fees consisted of a renewable fuel energy regulatory audit.

(3) Tax fees consisted of services related to tax compliance, the review of our partnership Form K-1, and research and consultation on other tax related matters.

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.

All fees paid or expected to be paid to Ernst & Young LLP for fiscal 2017 and 2016 were pre-approved by the audit committee in accordance with this policy.

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Part IV
Item 15. Exhibits, 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, 2017.

1. Sprague Resources LP Audited Consolidated Financial Statements:

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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:

Exhibit No.	Description
2.1***	Purchase and Sale Agreement, dated September 18, 2017, by and among Sprague Operating Resources LLC, Coen Oil Company, LLC, Coen Markets, Inc., and The Thomaston Land Company, LLC (incorporated by reference to Exhibit 2.1 of Sprague Resources LP's Current Report on Form 8-K filed September 19, 2017 (File No. 001-36137)).
2.2***	First Amendment dated April 18, 2017 to Asset Purchase Agreement by and among Sprague Operating Resources LLC, Carbo Industries, Inc. and Carbo Realty, LLC (incorporated by reference to Exhibit 2.1 of Sprague Resources LP's Current Report on Form 8-K filed April 19, 2017 (File No. 001-36137)).
2.3***	Asset Purchase Agreement, dated March 13, 2017, by and among Carbo Industries, Inc., Carbo Realty, LLC, and Paul Hochhauser and Sprague Operating Resources, LLC (incorporated by reference to Exhibit 2.1 of Sprague Resources LP's Current Report on Form 8-K filed March 16, 2017 (File No. 001-36137)).
2.4***	Asset Purchase Agreement, dated January 24, 2017, by and among Capital Properties, Inc., Dunellen, LLC, Capital Terminal Company and Sprague Operating Resources LLC (incorporated by reference to Exhibit 2.1 of Sprague Resources LP's Current Report on Form 8-K filed January 25, 2017 (File No. 001-36137)).
2.5***	Terminal and Wholesale Fuels Asset Purchase Agreement, dated January 23, 2017, by and between Leonard E. Belcher Incorporated and Sprague Operating Resources LLC (incorporated by reference to Exhibit 2.1 of Sprague Resources LP's Current Report on Form 8-K filed January 24, 2017 (File No. 001-36137)).

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Exhibit No.	Description
2.6***	Asset Purchase Agreement, dated December 30, 2016, by and among Sprague Operating Resources LLC, Sprague Energy Inc., Sprague Resources LP, Global Montello Group Corp., Global Energy Marketing LLC and Global Partners LP (incorporated by reference to Exhibit 2.1 of Sprague Resources LP's Current Report on Form 8-K filed January 3, 2017 (File No. 001-36137)).
3.1	Amendment No. 1 to the Amended and Restated Agreement of Limited Partnership of Sprague Resources LP dated as of October 30, 2013 effective December 20, 2017 (incorporated by reference to Exhibit 3.1 of Sprague Resources LP's Current Report on Form 8-K filed December 20, 2017 (File No. 001-36137).
3.2	First Amended and Restated Agreement of Limited Partnership of Sprague Resources LP (incorporated by reference to Exhibit 3.1 of Sprague Resources LP's Current Report on Form 8-K filed November 5, 2013 (File No. 001-36137)).
3.3	Amended and Restated Limited Liability Company Agreement of Sprague Resources GP LLC (incorporated by reference to Exhibit 3.2 of Sprague Resources LP's Current Report on Form 8-K filed November 5, 2013 (File No. 001-36137)).
10.1	Amended and Restated Credit Agreement, dated as of December 9, 2014, among Sprague Operating Resources LLC, as U.S. borrower, Sprague Resources ULC and Kildair Service Ltd., as initial Canadian borrowers, the several lenders parties thereto, JPMorgan Chase Bank, N.A., as administrative agent, JPMorgan Chase Bank, N.A., Toronto Branch, as Canadian 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 LP's Current Report on Form 8-K filed December 12, 2014 (File No. 001-36137)).
10.2	Amendment, dated as of March 10, 2016, to Amended and Restated Credit Agreement, dated as of December 9, 2014, among Sprague Operating Resources LLC, as U.S. borrower, Sprague Resources ULC and Kildair Service Ltd., as initial Canadian borrowers, the several lenders parties thereto, JPMorgan Chase Bank, N.A., as administrative agent, JPMorgan Chase Bank, N.A., Toronto Branch, as Canadian 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 LP's Current Report on Form 8-K filed March 11, 2016 (File No. 001-36137)).
10.3	Amendment to Amended and Restated Credit Agreement, dated April 27, 2017 among Sprague Operating Resources LLC, as U.S. borrower, Kildair Service ULC, as Canadian borrower, the several lenders party thereto, and JPMorgan Chase Bank, N.A., as administrative agent (incorporated by reference to Exhibit 2.1 of Sprague Resources LP's Current Report on Form 8-K filed April 28, 2017 (File No. 001-36137)).
10.4	Unit Purchase Agreement, dated March 13, 2017 by and between Sprague Resources, LP and Carbo Industries, Inc. (incorporated by reference to Exhibit 10.1 of Sprague Resources LP's Current Report on Form 8-K filed March 16, 2017 (File No. 001-36137)).
10.5	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 LP's Current Report on Form 8-K filed November 5, 2013 (File No. 001-36137)).

10.6	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 LP's Current Report on Form 8-K filed November 5, 2013 (File No. 001-36137)).
10.7	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 LP's Current Report on Form 8-K filed November 5, 2013 (File No. 001-36137)).
10.8†	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 28, 2013 (File No. 333-191923)).

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Exhibit No.	Description
10.9†	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)).
10.10†	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)).
10.11†	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)).
10.12†	Form of Phantom Unit Agreement (Performance Based Vesting) (incorporated by reference to Exhibit 10.1 of Sprague Resources LP’s Quarterly Report on Form 10-Q filed on August 13, 2014 (File No. 001-36137)).
10.13†	Amended and Restated Director Compensation Summary (incorporated by reference to Exhibit 10.1 of Sprague Resources LP’s Quarterly Report on Form 10-Q filed on November 7, 2016 (File No. 001-36137)).
10.14	Unit Purchase Agreement, dated November 4, 2014, by and between Sprague Resources LP and Castle Oil Corporation, dated November 4, 2014 (incorporated by reference to Exhibit 10.1 of Sprague Resources LP’s Current Report on Form 8-K filed November 5, 2014 (File No. 001-36137)).
10.15†	Form of Phantom Unit Agreement (Performance Based Vesting) (incorporated by reference to Exhibit 10.13 of Sprague Resources LP's Annual Report on Form 10-K filed March 10, 2016 (File No. 001-36137)).
12.1*	Computation of Ratio of Earnings to Combined Fixed Charges and Preference Dividends.
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.
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.
** Furnished herewith in accordance with Item 601(b)(32) of Regulation S-K.
*** Pursuant to Item 601(b)(2) of Regulation S-K, certain schedules to the Asset Purchase Agreements have been omitted. The registrant hereby agrees to furnish supplementally to the SEC, upon its request, any or all omitted schedules.

Item 16. Form 10-K Summary.

None.

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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 14, 2018

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 14, 2018
/s/ David C. Glendon David C. Glendon	President, Chief Executive Officer and Director (Principal Executive Officer)	March 14, 2018
/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 14, 2018
/s/ Beth A. Bowman Beth A. Bowman	Director	March 14, 2018
/s/ Robert B. Evans Robert B. Evans	Director	March 14, 2018
/s/ C. Gregory Harper	Director	March 14, 2018

C. Gregory Harper		
/s/ Ben J. Hennelly Ben J. Hennelly	Director	March 14, 2018
/s/ Sally A. Sarsfield Sally A. Sarsfield	Director	March 14, 2018

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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
Opinion on the Financial Statements
We have audited the accompanying consolidated balance sheets of Sprague Resources LP (the Partnership) as of December 31, 2017 and 2016, the related consolidated statements of operations, comprehensive income, unitholders' equity, and cash flows for each of the three years in the period ended December 31, 2017, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Partnership at December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with U.S. generally accepted accounting principles.
We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Partnership's internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated March 14, 2018 expressed an unqualified opinion thereon.
Basis for Opinion
These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on the Partnership's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.
We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.
/s/ Ernst & Young LLP

We have served as the Partnership's auditor since 2007.

Hartford, Connecticut
March 14, 2018

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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

Opinion on Internal Control over Financial Reporting

We have audited Sprague Resources LP's internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, Sprague Resources LP (the Partnership) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on the COSO criteria.

As indicated in the accompanying Management's Report Regarding Internal Control Over Financial Reporting , management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of Coen Energy, LLC and Coen Transport, LLC (collectively "Coen") and the business acquired from Global Partners LP ("Global"), which is included in the 2017 consolidated financial statements of the Partnership and constituted 3% of total assets as of December 31, 2017 and 2% of revenues and net income for the year then ended. Our audit of internal control over financial reporting of the Partnership also did not include an evaluation of the internal control over financial reporting of Coen and Global.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Partnership as of December 31, 2017 and 2016, the related consolidated statements of operations, comprehensive income, unitholders' equity, and cash flows for each of the three years in the period ended December 31, 2017, and the related notes and our report dated March 14, 2018 expressed an unqualified opinion thereon.

Basis for Opinion

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

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects.

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

Definition and Limitations of Internal Control Over Financial Reporting

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

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

/s/ Ernst & Young LLP
Hartford, Connecticut
March 14, 2018

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Sprague Resources LP
Consolidated Balance Sheets
(in thousands except units)

	December 31, 2017	December 31, 2016
Assets		
Current assets:		
Cash and cash equivalents	$6,815	$2,682
Accounts receivable, net	316,613	221,954
Inventories	335,859	318,899
Fair value of derivative assets	107,254	66,858
Other current assets	39,946	43,316
Total current assets	806,487	653,709
Fair value of derivative assets long-term	7,493	—
Property, plant, and equipment, net	350,059	251,101
Intangibles, net	71,891	23,446
Other assets, net	12,018	13,668
Goodwill	115,037	70,550
Total assets	$1,362,985	$1,012,474
Liabilities and unitholders' equity		
Current liabilities:		
Accounts payable	$205,105	$138,358
Accrued liabilities	49,038	45,491
Fair value of derivative liabilities	156,763	95,339
Due to General Partner	11,228	14,218
Current portion of working capital facilities	275,613	153,603
Current portion of other obligations	6,476	4,190
Total current liabilities	704,223	451,199
Commitments and contingencies		
Working capital facilities - less current portion	66,237	156,733
Acquisition facility	383,500	245,400
Fair value of derivative liabilities long-term	8,265	—
Other obligations, less current portion	49,625	16,955
Due to General Partner	1,678	1,269
Deferred income taxes	17,623	15,481
Total liabilities	1,231,151	887,037
Unitholders' equity:		
Common unitholders—public (10,446,539 and 9,207,473 units issued and outstanding as of December 31, 2017 and 2016, respectively)	193,977	175,314
Common unitholders—affiliated (12,106,348 and 2,034,378 units issued and outstanding as of December 31, 2017 and 2016, respectively)	(53,273)	(4,518)
Subordinated unitholders—affiliated (10,071,970 units issued and outstanding as of December 31, 2016)	—	(34,576)
Accumulated other comprehensive loss, net of tax	(8,870)	(10,783)
Total unitholders' equity	131,834	125,437
Total liabilities and unitholders' equity	$1,362,985	$1,012,474

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

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Sprague Resources LP
Consolidated Statements of Operations
(in thousands, except unit and per unit amounts)

	Years Ended December 31,		
	2017	2016	2015
Net sales	$2,854,996	$2,389,998	$3,481,914
Cost of products sold (exclusive of depreciation and amortization)	2,602,788	2,179,089	3,188,924
Operating expenses	72,284	65,882	71,468
Selling, general and administrative	87,582	84,257	94,403
Depreciation and amortization	28,125	21,237	20,342
Total operating costs and expenses	2,790,779	2,350,465	3,375,137
Operating income	64,217	39,533	106,777
Other income (expense)	108	(114)	298
Interest income	339	388	456
Interest expense	(31,345)	(27,533)	(27,367)
Income before income taxes	33,319	12,274	80,164
Income tax provision	(3,822)	(2,108)	(1,816)
Net income	$29,497	$10,166	$78,348
Incentive distributions declared	(3,993)	(1,742)	(321)
Limited partners’ interest in net income	$25,504	$8,424	$78,027
Net income per limited partner unit:			
Common—basic	$1.15	$0.40	$3.71
Common—diluted	$1.13	$0.38	$3.65
Subordinated—basic and diluted	N/A	$0.40	$3.71
Weighted-average units used to compute net income per limited partner unit:			
Common—basic	22,208,964	11,202,427	10,975,941
Common—diluted	22,474,872	11,560,617	11,141,333
Subordinated—basic and diluted	N/A	10,071,970	10,071,970
Distribution declared per unit	$2.46	$2.22	$1.98

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

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Sprague Resources LP
Consolidated Statements of Comprehensive Income
(in thousands)

	Years Ended December 31,		
	2017	2016	2015
Net income	$29,497	$10,166	$78,348
Other comprehensive income (loss), net of tax:			
Unrealized gain (loss) on interest rate swaps			
Net income (loss) arising in the period	1,884	223	(939)
Reclassification adjustment related to losses realized in income	(173)	1,519	504
Net change in unrealized loss (gain) on interest rate swaps	1,711	1,742	(435)
Tax effect	(14)	(25)	15
	1,697	1,717	(420)
Foreign currency translation adjustment	216	(861)	(1,386)
Other comprehensive income (loss)	1,913	856	(1,806)
Comprehensive income	$31,410	$11,022	$76,542

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

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Sprague Resources LP
Consolidated Statements of Unitholders' Equity
(in thousands)

	Common-Public	Common-Sprague Holdings	Subordinated Sprague Holdings	Incentive Distribution Rights	Accumulated Other Comprehensive Loss	Total
Balance as of December 31, 2014	$171,055	$(5,566)	$ (39,762)	$ —	$ (9,833)	$115,894
Net income	33,218	7,558	37,418	154	—	78,348
Other comprehensive income	—	—	—	—	(1,806)	(1,806)
Unit-based compensation	1,284	292	1,446	—	—	3,022
Distributions paid	(17,172)	(3,906)	(19,337)	(154)	—	(40,569)
Common units issued with annual bonus	2,088	479	2,372	—	—	4,939
Units withheld for employee tax obligations	(990)	(227)	(1,126)	—	—	(2,343)
Balance as of December 31, 2015	189,483	(1,370)	(18,989)	—	(11,639)	157,485
Net income	3,815	847	4,192	1,312	—	10,166
Other comprehensive income	—	—	—	—	856	856
Unit-based compensation	1,820	404	2,000	—	—	4,224
Distributions paid	(19,894)	(4,419)	(21,878)	(1,312)	—	(47,503)
Common units issued with annual bonus	1,748	392	1,939	—	—	4,079
Units withheld for employee tax obligations	(1,658)	(372)	(1,840)	—	—	(3,870)
Balance as of December 31, 2016	175,314	(4,518)	(34,576)	—	(10,783)	125,437
Conversion of subordinated units to common units	—	(40,393)	40,393	—	—	—
Net income	11,955	14,324	—	3,218	—	29,497
Other comprehensive income	—	—	—	—	1,913	1,913
Unit-based compensation	1,034	1,240	—	—	—	2,274
Distributions paid	(25,198)	(23,239)	(5,817)	(3,218)	—	(57,472)
Common units issued for Carbo acquisition	31,401	—	—	—	—	31,401
Common units issued with annual bonus	161	210	—	—	—	371
Units withheld for employee tax obligations	(690)	(897)	—	—	—	(1,587)
Balance as of December 31, 2017	$193,977	$(53,273)	$ —	$ —	$ (8,870)	$131,834

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

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Sprague Resources LP
Consolidated Statements of Cash Flows
(in thousands)

	Years Ended December 31,		
	2017	2016	2015
Cash flows from operating activities			
Net income	$29,497	$10,166	$78,348
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization (includes amortization of deferred debt issue costs)	33,361	25,211	23,893
(Gain) loss on sale of assets and insurance recoveries	(231)	189	(269)
Changes in fair value of contingent consideration	168	—	—
Provision for doubtful accounts	(206)	231	1,589
Non-cash unit-based compensation	2,274	3,681	8,436
Other	63	—	—
Deferred income taxes	857	387	147
Changes in assets and liabilities:			
Accounts receivable	(94,454)	(61,541)	127,202
Inventories	(12,247)	(77,235)	149,236
Prepaid expenses and other assets	4,253	17,051	7,751
Fair value of commodity derivative instruments	24,812	165,108	19,754
Due to/from General Partner and affiliates	(2,580)	759	(1,066)
Accounts payable, accrued liabilities and other	71,475	47,737	(127,408)
Net cash provided by operating activities	57,042	131,744	287,613
Cash flows from investing activities			
Purchases of property, plant and equipment	(46,955)	(15,986)	(14,899)
Proceeds from property insurance settlements and sale of assets	1,003	154	781
Business acquisitions	(107,317)	(29,065)	(447)
Net cash used in investing activities	(153,269)	(44,897)	(14,565)
Cash flows from financing activities			
Net borrowings (payments) under credit agreements	169,248	(59,910)	(198,917)
Net payments on capital leases, term debt and other obligations	(5,030)	(1,763)	(1,932)
Debt issue costs	(4,873)	(2,089)	(1,938)
Distributions to unitholders	(57,472)	(47,503)	(40,569)
Foreign exchange on capital lease obligations	—	6	(266)
Repurchased units withheld for employee tax obligations	(1,587)	(3,870)	(2,343)
Net cash provided by (used in) financing activities	100,286	(115,129)	(245,965)
Effect of exchange rate changes on cash balances held in foreign currencies	74	(10)	(189)
Net change in cash and cash equivalents	4,133	(28,292)	26,894
Cash and cash equivalents, beginning of period	2,682	30,974	4,080
Cash and cash equivalents, end of period	$6,815	$2,682	$30,974
Supplemental disclosure of cash flow information			
Cash paid for interest	$25,781	$24,231	$24,382
Cash paid for taxes	$1,689	$789	$3,929
Non-cash consideration related to acquisitions:			
Common units issued - Carbo	$31,401	—	—
Deferred consideration - Carbo	$27,284	—	—
Contingent consideration - Coen	$9,557	—	—

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

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Sprague Resources LP
Notes to Consolidated Financial Statements
(in thousands unless otherwise stated)

1. Description of Business and Summary of Significant Accounting Policies

Partnership Businesses

Sprague Resources LP (the “Partnership”) is a Delaware limited partnership formed on June 23, 2011 by Sprague Holdings and its General Partner engages in the purchase, storage, distribution and sale of refined products and natural gas, and provides storage and handling services for a broad range of materials.

Unless the context otherwise requires, references to “Sprague Resources,” and the “Partnership,” refer to Sprague Resources LP and its subsidiaries. Unless the context otherwise requires, references to “Axel Johnson” or the “Parent” or the "Sponsor" 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 owns, operates and/or controls a network of refined products and materials handling terminals located in the Northeast United States and in Quebec, Canada. The Partnership also utilizes third-party terminals in the Northeast United States 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 fuel, residual fuel oil, kerosene, jet fuel, gasoline and asphalt (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 United States. 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, crude oil, residual fuel oil, coal, petroleum coke, caustic soda, tallow, pulp and heavy equipment. The Partnership’s other operations include the purchase and distribution of coal, certain commercial trucking activities and the heating equipment service business.

As of December 31, 2017, the Parent, through its ownership of Sprague Holdings, owned 12,106,348 common units representing 54% of the limited partner interest in the Partnership. Sprague Holdings also owns the General Partner, which in turn owns a non-economic interest in the Partnership. Sprague Holdings currently holds incentive distribution rights ("IDRs") that entitle it to receive increasing percentages, up to a maximum of 50.0%, of the cash the Partnership distributes from distributable cash flow in excess of $0.474375 per unit per quarter. The maximum distribution of 50% does not include any distributions that Sprague Holdings may receive on any limited partner units that it owns. See Notes 20 and 22.

Prior to February 16, 2017, Sprague Holdings owned, 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 had 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 were to 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 were extinguished (not paid), each outstanding subordinated unit was immediately converted into one common unit and will thereafter participate pro rata with the other common units in distributions. On February 16, 2017, based upon meeting certain distribution and performance tests provided in the Partnership's partnership agreement, all 10,071,970 subordinated units outstanding converted to common units on a one-for-one basis.

Services Agreement

The Partnership, the General Partner and Sprague Holdings operate under a services agreement (the “Services Agreement”) pursuant to which the General Partner provides certain general and administrative and operational services to the Partnership and Sprague Holdings, and the Partnership and Sprague Holdings 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

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of the Services Agreement will expire on October 30, 2018 and 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.

As of December 31, 2017 the General Partner employed approximately 880 full-time employees who support the Partnership’s operations, 60 of whom were covered by five collective bargaining agreements. Three of these agreements, covering forty-seven employees are up for renewal in 2018. As of December 31, 2017, the Partnership's Canadian subsidiary had 101 employees, 37 of whom were covered by one collective bargaining agreement which expires March 18, 2021.

Basis of Presentation

The Consolidated Financial Statements include the accounts of the Partnership and its wholly-owned subsidiaries. Intercompany transactions between the Partnership and its subsidiaries have been eliminated.

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 net sales and expenses in the income statement. Actual results could differ from those estimates. Among the estimates made by management are asset and liability valuations as part of an acquisition, the fair value of derivative assets and liabilities, valuation of contingent consideration, valuation of reporting units within the goodwill impairment assessment, and if necessary long-lived asset impairments and environmental and legal obligations.

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 estimated cash discounts are recorded as a reduction of revenue at the time of sale. Cash discounts were $5.9 million, $3.7 million and $6.3 million for the years ended December 31, 2017, 2016 and 2015, respectively. At the time of recognition for all revenue producing activities, persuasive evidence of an arrangement exists, delivery or service has occurred, the price is fixed or determinable, and collectability is reasonably assured.

Refined products revenue-producing activities are direct sales to customers including throughput and exchange transactions. 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 (exclusive of depreciation and amortization). Natural gas revenue-producing activities are 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.

An allowance for doubtful accounts is recorded to reflect an estimate of the ultimate realization of the Partnership's 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 (exclusive of depreciation and amortization).

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

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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. The use of these derivative instruments within the Partnership's risk management policy may, on a limited basis, generate gains or losses from changes in market prices. The Partnership enters into 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 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 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. Substantially all of the Partnership's commodity derivative contracts outstanding as of December 31, 2017 will settle prior to June 30, 2019.

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) each period. 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, 2017 or 2016.

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 (loss) and accumulated other comprehensive income (loss), net of tax. Any ineffective portion of the changes in fair value of the swaps is recorded in interest expense.

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 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 its 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.

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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 deposits 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 determines fair value based on 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 OTC 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. The Partnership utilizes fair value measurements based on Level 3 inputs for its contingent consideration obligation.

Long-Term Incentive Plan

The General Partner adopted the Sprague Resources LP 2013 Long-Term Incentive Plan (the "LTIP"), 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 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.

The board of directors of the General Partner grants performance-based phantom unit awards to key employees that vest over a period of time (usually three years). Upon vesting, a holder of performance-based phantom units is entitled to receive a number of common units of the Partnership equal to a percentage (between 0 and 200%) of the phantom units granted, based on the Partnership's achieving pre-determined performance criteria. The Partnership uses authorized but unissued units to satisfy its unit-based obligations.

TUR-based Phantom Units

Phantom unit awards granted in 2015, include a market condition criteria that considers the Partnership's total unitholder return ("TUR") over the three year vesting period, compared with the total unitholder return of a peer group of other master limited partnership energy companies over the same period. These awards are equity awards with both service and market-based conditions, which results in compensation cost being recognized over the requisite service period, provided that the requisite service period is fulfilled, regardless of when, if ever, the market based conditions are satisfied. The fair value of the TUR based phantom units was estimated at the date of grant based on a Monte Carlo model that estimates the most likely performance outcome based on the terms of the award. The key inputs in the model include the market price of the Partnership's common units as of the valuation date, the historical volatility of the market price of the Partnership's common units, the historical volatility of the market price of the common units or common stock of the peer companies and the correlation between changes in the market price of the Partnership's common units and those of the peer companies.

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OCF-based Phantom Units
Phantom unit awards granted in 2017 and 2016 include a performance criteria that considers Sprague Holdings operating cash flow, as defined therein ("OCF"), over a three year performance period. The number of common units that may be received in settlement of each phantom unit award can range between 0 and 200% of the number of phantom units granted based on the level of OCF achieved during the vesting period. These awards are equity awards with performance and service conditions which result in compensation cost being recognized over the requisite service period once payment is determined to be probable. Compensation expense related to the OCF based awards is estimated each reporting period by multiplying the number of common units underlying such awards that, based on the Partnership's estimate of OCF, are probable to vest, by the grant-date fair value of the award and is recognized over the requisite service period using the straight-line method. The fair value of the OCF based phantom units was the grant date closing price listed on the New York Stock Exchange. The number of units that the Partnership estimates are probable to vest could change over the vesting period. Any such change in estimate is recognized as a cumulative adjustment calculated as if the new estimate had been in effect from the grant date.
Distribution Equivalent Rights
The Partnership's performance-based phantom unit awards include tandem distribution equivalent rights ("DERs") which entitle the participant to a cash payment only upon vesting that is equal to any cash distribution paid on a common unit between the grant date and the date the phantom units were settled. Payments made in connection with DERs are recorded as a distribution in unitholders' equity.
Earnings (Loss) Per Unit
The Partnership computes income (loss) 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 was 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 (loss) was allocated to the partners based on their respective sharing of income specified in the partnership agreement. Net income (loss) per unit was determined by dividing the net income (loss) allocated to the common unitholders and the subordinated unitholders under the two-class method by the number of common units and subordinated units outstanding in the period. As previously noted, on February 16, 2017, based upon meeting certain distribution and performance tests provided in the Partnership's partnership agreement, all 10,071,970 subordinated units outstanding converted to common units on a one-for-one basis.
As discussed in Note 20, there was no allocation between the common unitholders and subordinated unitholders for the year ended December 31, 2017 since all subordinated units outstanding were converted to common units on February 16, 2017, and the subordinated units did not share in any distribution of cash generated during 2017.
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 common units in future periods if there are material differences between net income (loss) 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 net realizable value. Cost is primarily determined using the first-in, first-out method, except for the Partnership'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:

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Furniture and fixtures	5 to 10 years
Plant and machinery	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.

Long-lived Asset Impairment

The Partnership evaluates the carrying value of its property, plant and equipment and finite lived intangible assets for impairment when events or changes in circumstances indicate the carrying amount of an individual asset or asset group may not be recoverable based on estimated future undiscounted cash flows. Future cash flow projections include assumptions of future sales levels, the impact of controllable cost reduction programs, and the level of working capital needed to support each business. To the extent the carrying amount of the asset group 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 individual assets or asset group.

Purchase Price Allocation

The cost of an acquired entity is allocated to the assets acquired and liabilities assumed based on their respective fair values at the date of acquisition. Property, plant and equipment and goodwill generally represent large components of these acquisitions. In addition to goodwill, intangible assets acquired generally include 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.

For all material acquisitions the Partnership determines the fair value of the assets acquired and liabilities assumed, including goodwill, based on recognized business valuation methodologies. An income, market or cost valuation method may be utilized to estimate the fair value of the assets acquired or liabilities assumed. The income valuation method represents the present value of future cash flows over the life of the asset using: (i) discrete financial forecasts, based on management’s estimates of revenue and operating expenses; (ii) long-term growth rates; and (iii) appropriate discount rates. The market valuation method uses prices paid for a reasonably similar asset by other purchasers in the market, with adjustments relating to any differences between the assets. The cost valuation method is based on the replacement cost of a comparable asset at prices at the time of the acquisition reduced for depreciation of the asset.

For contingent consideration arrangements, a liability is recognized at fair value as of the acquisition date with subsequent fair value adjustments recorded in operations. Additional information regarding the Partnership's contingent consideration arrangements may be found in Note 2, Acquisitions, Note 13 Other Obligations and Note 17, Financial Instruments and Off-Balance Sheet Risk.

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, including goodwill. If the fair value of the reporting unit exceeds its carrying value, goodwill is not impaired. If the carrying value of the reporting unit exceeds its fair value, the Partnership will determine if there is a potential impairment by comparing the implied fair value of goodwill with the carrying amount. If the implied fair value of goodwill is less than the carrying amount, an impairment loss would be reported. 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.

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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 also used a range of discount rate assumptions to evaluate the sensitivity on the fair values resulting from the discounted cash flow valuation.

Intangibles, Net

Intangibles, net consist of intangible assets with finite lives, primarily customer relationships and non-compete agreements. Intangibles and other assets are amortized over their respective estimated useful lives. 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.

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 U.S. federal income taxes based on their respective share of taxable income. Net income (loss) 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 Sprague Energy Solutions, Inc., a taxable corporate subsidiary. Sprague Energy Solutions, Inc. is subject to U.S. federal and state income tax and pays any income taxes related to the results of its operations. For the year ended December 31, 2017, 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 as well as foreign jurisdictions.

Income taxes (e.g., deferred tax assets, deferred tax liabilities, 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's Canadian operations are conducted within entities that are treated as corporations for Canadian tax purposes and are subject to Canadian federal and provincial taxes. Additionally, payments of dividends from the Partnership's Canadian entities to other Sprague entities are subject to Canadian withholding tax that is treated as income tax expense. As of December 31, 2017, the partnership had foreign investment tax credit carry forwards of $0.2 million, all of which were generated in Canada, which begin to expire in 2035. The partnership's foreign subsidiaries record investment tax credits under the deferral method.

The Partnership recognizes the financial statement effect of an uncertain 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. During the years ended December 31, 2017, 2016 and 2015, the interest and penalties recognized by the Partnership were immaterial. The Partnership and its subsidiaries tax returns are subject to examination by the Internal Revenue Service for the years ended December 31, 2016, 2015 and 2014 and by the Canada Revenue Agency for the years ended December 31, 2016, 2015, 2014 and 2013.

On December 22, 2017, the President signed into law Public Law No. 115-97, a comprehensive tax reform bill commonly referred to as the Tax Cuts and Jobs Act (the "Tax Act") that makes significant changes to the U.S. Internal Revenue Code. Among other changes, the Tax Act includes a new deduction on certain pass-through income, a repeal of the partnership technical termination rule, and new limitations on certain deductions and credits, including interest expense deductions. Since the operations of the Partnership are generally not subject to federal income tax, the Tax Act is not expected to have a material impact to the Partnership.

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Foreign Currency

The Partnership’s reporting currency is the U.S. dollar. The Partnership's most significant foreign operations are conducted by Kildair, a Canadian subsidiary. The functional currency of Kildair is the U.S. Dollar. Kildair has an operating subsidiary whose functional currency is the Canadian dollar.

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 Canadian 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 (loss) as these forward currency contracts have not been designated as hedges. For the years ended December 31, 2017, 2016 and 2015, transaction exchange gains or losses net of the impact of the forward currency exchange contracts, except for certain transaction gains or losses related to intercompany receivable and payables, amounted to gains of $0.3 million, $0.1 million and $1.3 million, respectively, which is recorded in cost of products sold (exclusive of depreciation and amortization).

Recent Accounting Pronouncements

In July 2017, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) No. 2017-12, Derivatives and Hedging: Targeted Improvements to Accounting for Hedging Activities. The objective of the guidance is to improve the financial reporting of hedging relationships to better portray the economic results of an entity’s risk management activities in its financial statements. This ASU is effective for fiscal years beginning after December 15, 2018, and interim periods within those fiscal years. The Partnership is currently evaluating the impact of this new standard on the consolidated financial statements.

In January 2017, the FASB issued ASU 2017-04 Intangibles - Goodwill and Other (Topic 350): Simplifying the Accounting for Goodwill Impairment. The guidance removes Step 2 of the goodwill impairment test, which requires a hypothetical purchase price allocation. A goodwill impairment will now be the amount by which a reporting unit’s carrying value exceeds its fair value, not to exceed the carrying amount of goodwill. The standard will be applied prospectively, and is effective for fiscal years beginning after December 15, 2019. Early adoption is permitted for any impairment tests performed after January 1, 2017.

In January 2017, the FASB issued ASU 2017-01 Business Combinations (Topic 805), which clarifies the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. This ASU is effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years. The Partnership will consider this new guidance for transactions entered into after December 31, 2017.

In August 2016, the FASB issued ASU 2016-15 Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments, which addresses eight specific cash flow issues with the objective of reducing diversity in practice in how certain cash receipts and cash payments are presented and classified in the statement of cash flows under Topic 230, Statement of Cash Flows, and other Topics. The Partnership has not yet adopted the provisions of this ASU, which is effective for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years and is to be applied retrospectively to all periods presented. Early application is permitted, including adoption in an interim period. The adoption of this new guidance is not expected to have a material impact on the Partnership's consolidated statement of cash flows.

In March 2016, the FASB issued ASU 2016-09 Compensation- Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting, which addresses areas for simplification involving several aspects of the accounting for share-based payment transactions including, among other things, income tax consequences of excess benefits and deficiencies, classification of awards as either equity or liabilities, classification on the statement of cash flows, and the use of forfeiture estimates. The Partnership adopted the provisions of this ASU in 2017, which did not have a material impact to the Partnership's consolidated financial statements.

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In February 2016, the FASB issued ASU 2016-02 Leases (Topic 842), which, among other things, requires lessees to recognize at the commencement date of a lease a liability, which is a lessee's obligation to make lease payments arising from a lease, measured on a discounted basis, and a right-of-use asset, which is an asset that represents the lessee's right to use, or control the use of, a specified asset for the lease term. Under the new guidance, lessor accounting is largely unchanged. This ASU is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. Early application is permitted. Lessees and lessors must apply a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. The modified retrospective approach would not require any transition accounting for leases that expired before the earliest comparative period presented. Lessees and lessors may not apply a full retrospective transition approach. The Partnership is currently evaluating the impact of this new standard on the consolidated financial statements.

In July 2015, the FASB issued ASU 2015-11, Simplifying the Measurement of Inventory, which requires that inventory within the scope of the guidance be measured at the lower of cost or net realizable value. The Partnership adopted
the provisions of this ASU in 2017 which did not have a material impact to the Partnership's consolidated financial statements.

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606), which revises the principles of revenue recognition from one based on the transfer of risks and rewards to when a customer obtains control of a
good or service. The FASB has issued several ASUs subsequent to ASU 2014-09 in order to clarify implementation guidance but did not change the core principle of the guidance in Topic 606. These ASUs are effective for fiscal years beginning after
December 15, 2017, including interim periods within those fiscal years. The Partnership expects to adopt this guidance on January 1, 2018, using the modified retrospective approach, under which the cumulative effect of initially applying the new guidance is recognized as an adjustment to the opening balance of unitholders' equity. The Partnership has finalized its analysis and has concluded that the adoption of ASU 2014-09 will not have an impact to the consolidated financial statements and does not expect significant changes to business processes, systems, or internal controls as a result of adopting the standard.

2. Business Combinations

The Partnership completed five business acquisitions during the year ended December 31, 2017 and one business acquisition during the year ended December 31, 2016, as described below. Allocations of the preliminary purchase price to the assets acquired and liabilities assumed have been made to record, where applicable, inventory, derivative assets and liabilities, natural gas transportation assets and liabilities, property, plant and equipment, identifiable intangible assets such as customer relationships and non-compete agreements as well as goodwill.

In connection with these acquisitions the Partnership recognized \$3.0 million and \$0.1 million of acquisition related costs during the year ended December 31, 2017 and 2016, respectively, which were expensed and are included in selling, general and administrative expense.

Year Ended December 31, 2017

Coen Energy

On October 1, 2017, the Partnership purchased the membership interests of Coen Energy, LLC and Coen Transport, LLC, as well as assets consisting of four bulk plants and underlying real estate (collectively, “Coen Energy”). Initial cash consideration, not including the purchase of inventory and other adjustments, was \$35.3 million in cash which was financed with borrowings under the Credit Agreement (see note 5). In addition, contingent consideration of up to \$12 million is payable based on achieving certain economic performance measures during the three year period ending September 30, 2020. The Partnership has estimated the fair value of the contingent consideration to be \$9.6 million as of the date of the acquisition resulting in total consideration of \$44.9 million. See Note 17, Financial Instruments and Off-Balance Sheet Risk, for additional information regarding the Partnership’s contingent consideration obligation. The operations of Coen Energy are included in the Partnership's refined products segment since the acquisition date.

Coen Energy, located in Washington, PA, currently provides energy products and complimentary energy field services to over 7,000 energy field services, commercial, and residential customers located in Pennsylvania, Ohio and West Virginia. The Coen Energy business provides, among other things, fuel sales, delivery and related services supporting Marcellus and Utica shale drilling activity. The Coen Energy business is supported by four in-land bulk plants, two throughput locations, approximately 100 delivery vehicles and approximately 250 employees.

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The following table summarizes the preliminary fair values of the assets acquired and liabilities assumed at the acquisition date:

Inventories	$567
Other current assets	115
Property, plant and equipment	12,972
Intangibles	18,375
Total identifiable assets acquired	32,029
Other liabilities	(256)
Net identifiable assets acquired	31,773
Goodwill	13,095
Net assets acquired	$44,868

The goodwill recognized is primarily attributable to Coen’s reputation in it's geographic market area, the in-place workforce and the residual cash flow the Partnership believes that it will be able to generate. The goodwill is expected to be deductible for tax purposes.

Carbo Terminals

On April 18, 2017, the Partnership acquired substantially all of the assets of Carbo Industries, Inc. and certain of its affiliates (together “Carbo”) by purchasing Carbo's Inwood and Lawrence, New York refined product terminal assets and its associated wholesale distribution business. The fair value of the consideration totaled $72.0 million and consisted of $13.3 million in cash that was financed through borrowings under the Credit Agreement, an obligation to pay $38.2 million over a ten year period (estimated net present value of $27.3 million) and $31.4 million in unregistered common units. The Carbo terminals have a combined gasoline, ethanol and distillate storage capacity of 174,000 barrels and are supplied primarily by pipeline with the ability to also accept product deliveries by barge and truck. The operations of Carbo are included in the Partnership's refined products segment since the acquisition date.

The following table summarizes the fair values of the assets acquired and liabilities assumed at the acquisition date:

Inventories	$3,220
Derivative assets and other assets	111
Property, plant and equipment	22,995
Intangibles	29,000
Total identifiable assets acquired	55,326
Other liabilities	(188)
Net identifiable assets acquired	55,138
Goodwill	16,718
Net assets acquired	$71,856

The goodwill recognized is primarily attributable to Carbo’s reputation in the New York City area, the in-place workforce and the residual cash flow the Partnership believes that it will be able to generate. The goodwill is expected to be deductible for tax purposes.

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Capital Terminal

On February 10, 2017, the Partnership purchased the East Providence, Rhode Island refined product terminal business of Capital Properties Inc. (the “Capital Terminal”). Consideration paid was $22.0 million and was financed with borrowings under the Credit Agreement. The terminal’s distillate storage capacity of 1.0 million barrels had been leased by the Partnership since April 2014 and was previously included in the Partnership’s total storage capacity. The operations of the Capital Terminal are included in the Partnership's refined products segment since the acquisition date.

The following table summarizes the fair values of the assets acquired and liabilities assumed at the acquisition date:

Property, plant and equipment	$21,960
Accrued liabilities and other, net	(22)
Net assets acquired	$21,938

Global Natural Gas & Power

On February 1, 2017, the Partnership purchased the natural gas marketing and electricity brokering business of Global Partners LP ("Global Natural Gas & Power") for $17.3 million, not including the purchase of natural gas inventory, assumption of derivative assets (liabilities) and other adjustments. Consideration paid was $16.3 million and was financed with borrowings under the Credit Agreement. This business markets natural gas and electricity to commercial, industrial, municipal and institutional customer locations in the Northeast United States. The operations of Global Natural Gas & Power are included in the Partnership's natural gas segment since the acquisition date.

The following table summarizes the fair values of the assets acquired and liabilities assumed at the acquisition date:

Inventory	$286
Derivative assets	5,873
Natural gas transportation assets	695
Derivative assets long term	1,089
Natural gas transportation assets long term	378
Intangibles	5,046
Total identifiable assets acquired	13,367
Derivative liabilities	(4,865)
Natural gas transportation liabilities	(465)
Derivative liabilities long term	(1,214)
Natural gas transportation liabilities long term	(162)
Net identifiable assets acquired	6,661
Goodwill	9,592
Net assets acquired	$16,253

The goodwill recognized is primarily attributable to Global Natural Gas & Power’s reputation in its market regions, the in-place workforce and the residual cash flow the Partnership believes that it will be able to generate. The goodwill is expected to be deductible for tax purposes.

L.E. Belcher Terminal

On February 1, 2017, the Partnership purchased the Springfield, Massachusetts refined product terminal assets of Leonard E. Belcher, Incorporated (“L.E. Belcher”) for approximately $20.0 million, not including the purchase of inventory, assumption of derivative assets (liabilities) and other adjustments. Consideration paid was $20.7 million and was financed with borrowings under the Credit Agreement. The purchase consists of two pipeline-supplied distillate terminals and one distillate storage facility with a combined capacity of 283,000 barrels, as well as L.E. Belcher’s associated wholesale and commercial fuels businesses. The operations of L.E. Belcher are included in the Partnership's refined products segment since the acquisition date.

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The following table summarizes the fair values of the assets acquired and liabilities assumed at the acquisition date:

Inventories	$632
Derivative and other current assets	658
Property, plant and equipment	9,152
Intangibles	5,800
Total identifiable assets acquired	16,242
Derivative and other current liabilities	(680)
Net identifiable assets acquired	15,562
Goodwill	5,081
Net assets acquired	$20,643

The goodwill recognized is primarily attributable to LEB's reputation in the Springfield, Massachusetts area, the in-place workforce and the residual cash flow the Partnership believes that it will be able to generate. The goodwill is expected to be deductible for tax purposes.

Following is the unaudited pro forma consolidated net sales and net income as if the businesses acquired during the year ended December 31, 2017 had been included in the consolidated results of the Partnership for the twelve months ended December 31, 2017 and 2016:

	Years Ended December 31,	
	2017	2016
	(unaudited)	
Net sales	$2,957,205	$2,590,663
Net income	29,431	4,216
Limited partners' interest in net income	25,438	2,474
Net income per limited partner common unit-basic	1.15	0.12
Net income per limited partner common unit-diluted	1.13	0.11

These amounts have been calculated after applying the Partnership's accounting policies and adjusting the results of the acquired businesses to reflect the depreciation and amortization that would have been charged assuming the fair value adjustments to property, plant and equipment and intangible assets had been applied on January 1, 2016, together with an adjustment to reflect taxes as a pass-through entity for U.S. federal income tax purposes. The net sales and net income (loss) of the acquired businesses included in the Partnership's consolidated operating results from their respective acquisition dates, through the year ended December 31, 2017 were $142.8 million and $(10.3) million, respectively.

Year Ended December 31, 2016

Natural Gas Business of Santa Buckley Energy, Inc.

On February 1, 2016, the Partnership purchased the natural gas business of Santa Buckley Energy, Inc. ("SBE") for $17.5 million, not including the purchase of natural gas inventory, utility security deposits, and other adjustments. Total consideration at closing was $29.1 million. SBE markets natural gas to commercial, industrial and municipal consumers in the Northeast United States. The acquisition was accounted for as a business combination and was financed with borrowings under the Partnership's credit facility. The operations of SBE are included in the Partnership's natural gas segment since the acquisition date.

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The following table summarizes the fair values of the assets acquired and liabilities assumed:

Derivative assets	$22,678
Other current assets and prepaids	2,168
Intangibles and other	6,539
Natural gas transportation assets	8,040
Total identifiable assets acquired	39,425
Accrued liabilities	(219)
Derivative liabilities	(15,007)
Natural gas transportation liabilities	(2,396)
Net identifiable assets acquired	21,803
Goodwill	7,262
Net assets acquired	$29,065

The goodwill recognized is primarily attributable to SBE's reputation in the Northeast United States and the residual cash flow the Partnership believes that it will be able to generate. The goodwill is expected to be deductible for tax purposes.

3. 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,	
	2017	2016
Fair value of interest rate swaps, net of tax	$2,588	$891
Cumulative foreign currency translation adjustment	(11,458)	(11,674)
Accumulated other comprehensive loss, net of tax	$(8,870)	$(10,783)

4. Accounts Receivable, Net

	As of December 31,	
	2017	2016
Accounts receivable, trade	$310,800	$217,731
Less allowance for doubtful accounts	(2,014)	(4,282)
Net accounts receivable, trade	308,786	213,449
Accounts receivable, other	7,827	8,505
Accounts receivable, net	$316,613	$221,954

Unbilled accounts receivable, included in accounts receivable, trade at December 31, 2017 and 2016 were $81.6 million and $50.9 million, respectively. Unbilled receivables relate primarily to the delivery and sale of natural gas to customers in the current month for which the right to bill exists. Such amounts generally are invoiced to the customer the following month when actual usage data becomes available. Accounts receivable, other consists primarily of product tax receivables.

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A reconciliation of the beginning and ending amount of allowance for doubtful accounts follows:

	Balance at Beginning of Period	Charged to Expense	Charged (to) from Another Account	(Deductions)	Balance at End of Period
Balance, December 31, 2017:					
Allowance for doubtful accounts	$ 4,282	$ (207)	$ 11	$ (2,072)	$ 2,014
Allowance for notes receivable	641	—	(11)	(99)	531
Total	$ 4,923	$ (207)	$ —	$ (2,171)	$ 2,545
Balance, December 31, 2016:					
Allowance for doubtful accounts	$ 4,139	$ 230	$ 20	$ (107)	$ 4,282
Allowance for notes receivable	1,401	—	(20)	(740)	641
Total	$ 5,540	$ 230	$ —	$ (847)	$ 4,923
Balance, December 31, 2015:					
Allowance for doubtful accounts	$ 3,976	$ 1,589	$ 7	$ (1,433)	$ 4,139
Allowance for notes receivable	2,367	—	(7)	(959)	1,401
Total	$ 6,343	$ 1,589	$ —	$ (2,392)	$ 5,540

Notes receivable, net of allowance, are generally long-term arrangements and were fully reserved as of December 31, 2017 and 2016.

5. Inventories

	As of December 31, 2017	2016
Petroleum and related products	$324,491	$305,827
Asphalt	5,221	7,089
Coal	3,712	3,149
Natural gas	2,435	2,834
Inventories	$335,859	$318,899

Due to changing market conditions, the Partnership recorded a provision of $0.4 million, $1.7 million and $27.9 million as of December 31, 2017, 2016 and 2015, respectively, to write-down petroleum, natural gas and asphalt inventory to its net realizable value. These charges are included in cost of products sold (exclusive of depreciation and amortization).

6. Other Current Assets

	As of December 31, 2017	2016
Margin deposits with brokers	$29,321	$33,193
Prepaid software & fees	7,200	4,845
Natural gas transportation	1,056	2,504
Other	2,369	2,774
Other current assets	$39,946	$43,316

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7. Property, Plant and Equipment, Net

	As of December 31,	
	2017	2016
Plant, machinery, furniture and fixtures	$401,092	$314,880
Building and leasehold improvements	18,631	14,420
Land and land improvements	86,758	60,863
Construction in progress	6,580	8,451
Property, plant and equipment, gross	513,061	398,614
Less: accumulated depreciation	(163,002)	(147,513)
Property, plant and equipment, net	$350,059	$251,101

Depreciation expense for the years ended December 31, 2017, 2016 and 2015 was $18.3 million, $16.0 million and $15.9 million, respectively.

Property, plant and equipment include the following amounts under capital leases:

	As of December 31,	
	2017	2016
Plant, machinery, furniture and fixtures	$17,131	$16,664
Building and leasehold improvements	962	4,719
Land and land improvements	251	251
Property, plant and equipment, gross	18,344	21,634
Less: accumulated amortization	(9,117)	(10,186)
Property, plant and equipment, net	$9,227	$11,448

Amortization expense on capital leased assets is included in depreciation expense and for the years ended December 31, 2017, 2016 and 2015 was $1.6 million, $1.5 million and $1.4 million, respectively.

8. Intangibles, Net

	As of December 31, 2017			
	Remaining Useful Life (Years)	Gross	Accumulated Amortization	Net
Customer relationships	1 - 25	$84,219	$ 21,595	$62,624
Non-compete agreements	2 - 5	13,587	5,317	8,270
Other	1 - 5	2,500	1,503	997
Intangible assets, net		$100,306	$ 28,415	$71,891

	As of December 31, 2016			
	Remaining Useful Life (Years)	Gross	Accumulated Amortization	Net
Customer relationships	2-17	$36,265	$ 14,396	$21,869
Non-compete agreements	2-5	4,095	3,056	1,039
Other	3-5	1,726	1,188	538
Intangible assets, net		$42,086	$ 18,640	$23,446

The Partnership recorded amortization expense related to intangible assets of $9.8 million, $5.2 million and $4.4 million during the years ended December 31, 2017, 2016 and 2015, respectively. The amortization of intangible assets is recorded in depreciation and amortization expense.

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During the year ended December 31, 2017, the Partnership acquired intangible assets of $58.2 million (consisting of $47.9 million of customer relationships, $9.5 million of non-compete agreements and $0.8 million of other intangibles). During the year ended December 31, 2016, the Partnership acquired intangible assets of $6.5 million (consisting of $5.8 million of customer relationships and $0.7 million of other intangibles). See Note 2.

The estimated future annual amortization expense of intangible assets for the years ending December 31, 2018, 2019, 2020, 2021 and 2022 is $12.0 million, $10.3 million, $8.7 million, $7.2 million and $5.8 million, respectively. As acquisitions and dispositions occur in the future, these amounts may vary.

9. Other Assets, Net

	As of December 31, 2017	2016
Deferred debt issuance costs, net	$11,625	$12,121
Natural gas transportation, long-term portion	37	445
Other	356	1,102
Other assets, net	$12,018	$13,668

Deferred Debt Issuance Costs

The Partnership recorded amortization expense related to deferred debt issuance costs of $5.2 million, $4.0 million and $3.6 million during the years ended December 31, 2017, 2016 and 2015, respectively. The amortization expense for the year ended December 31, 2017 included a write-off of $1.6 million attributable to the refinancing and extension of our credit agreement (see Note 11). Deferred debt issuance costs are amortized over the life of the related debt on a straight-line basis and recorded in interest expense.

Natural Gas Transportation Assets

The Partnership records the fair value of natural gas transportation contracts acquired in business combinations. In 2017, the Partnership recorded an asset of $1.1 million and a liability of $0.6 million in connection with the Global Natural Gas & Power acquisition. In 2016, the Partnership recorded an asset of $8.0 million and a liability of $2.4 million in connection with the SBE acquisition.

These assets and liabilities are being amortized into cost of products sold (exclusive of depreciation and amortization) in the natural gas segment over the life of the underlying agreements. During the year ended December 31, 2017, 2016 and 2015, the Partnership recorded a charge to cost of products sold (exclusive of depreciation and amortization) of $1.8 million, $6.5 million and $13.4 million, respectively, which included $0.3 million, $1.6 million and $3.6 million, respectively, due to a decline in value as a result of decreasing natural gas spreads.

Natural gas transportation assets, net as of December 31, 2017 and 2016 was $0.5 million and $1.7 million, respectively. The net amount expected to be expensed in the year ended December 31, 2018 is approximately $0.5 million and has been recorded in other current assets and other current liabilities.

10. Accrued Liabilities

	As of December 31, 2017	2016
Accrued product costs	$11,517	$5,976
Accrued product taxes	9,783	8,623
Customer prepayments and deposits	8,178	13,604
Other	19,560	17,288
Other current liabilities	$49,038	$45,491

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11. Credit Agreement

	As of December 31,	
	2017	2016
Working capital facilities	$341,850	$310,336
Acquisition facility	383,500	245,400
Total credit agreement	725,350	555,736
Less: current portion of working capital facilities	(275,613)	(153,603)
Total long-term portion	$449,737	$402,133

On April 27, 2017, Sprague Operating Resources LLC and Kildair Service ULC ("Kildair") entered into an agreement that amended and restated the revolving credit agreement to extend the maturity through April 27, 2021, reduce the U.S. dollar working capital facility from $1.0 billion to $950.0 million, reduce the multicurrency working capital facility from $120.0 million to $100.0 million, reduce interest rates margins for the acquisition facilities under certain leverage ratio scenarios, as well as make other modifications. Obligations under the Credit Agreement are secured by substantially all of the assets of the Partnership and its subsidiaries.

As of December 31, 2017, the revolving credit facilities under the Credit Agreement contained, among other items, the following:

- A U.S. dollar revolving working capital facility of up to $950.0 million, subject to the Partnership's borrowing base limits, to be used by the Partnership for working capital loans and letters of credit;
- A multicurrency revolving working capital facility of up to $100.0 million, subject to Kildair's borrowing base limits, to be used for working capital loans and letters of credit;
- Revolving acquisition facility of up to $550.0 million, subject to the Partnership's acquisition facility borrowing base limits, to be used for loans and letters of credit to fund capital expenditures and acquisitions and other general corporate purposes related to the Partnership’s current businesses, and
- Subject to certain conditions including the receipt of additional commitments from lenders, the ability to increase the U.S. dollar or revolving working capital facility by $250.0 million and the multicurrency revolving working capital facility by $220.0 million subject to a maximum increase for both facilities of $270.0 million in the aggregate. Additionally, subject to certain conditions, the revolving acquisition facility may be increased by $200.0 million.

Indebtedness under the Credit Agreement bears interest, at the borrowers' option, at a rate per annum equal to either (i) the Eurocurrency Base Rate (which is the LIBOR Rate for loans denominated in U.S. dollars and CDOR for loans denominated in Canadian dollars, in each case adjusted for certain regulatory costs) for interest periods of one, two, three or six months plus a specified margin or (ii) an alternate rate plus a specified margin.

For loans denominated in U.S. dollars, the alternate rate is the Base Rate which is the higher of (a) the U.S. Prime Rate as in effect from time to time, (b) the greater of Federal Funds Effective Rate and the Overnight Bank Funding Rate as in effect from time to time plus 0.50% and (c) the one-month Eurocurrency Rate for U.S. dollars as in effect from time to time plus 1.00%.

For loans denominated in Canadian, the alternate rate is the Prime Rate which is the higher of (a) the Canadian Prime Rate as in effect from time to time and (b) the one-month Eurocurrency Rate for U.S. dollars as in effect from time to time plus 1.00%.

The working capital facilities are subject to borrowing base reporting and as of December 31, 2017 and 2016, had a borrowing base of $623.2 million and $525.4 million, respectively. As of December 31, 2017 and 2016, outstanding letters of credit were $72.3 million and $31.6 million, respectively. As of December 31, 2017, excess availability under the working capital facility was $209.0 million and excess availability under the acquisition facilities was $166.5 million.

The weighted average interest rate was 4.2% and 3.4% at December 31, 2017 and 2016, respectively. No amounts are due under the Credit Agreement until the maturity date, however, the current portion of the Credit Agreement at December 31, 2017 and 2016 represents the amounts of the working capital facility intended to be repaid during the following twelve month period.

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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 indebtedness. The Credit Agreement limits the Partnership's ability to make distributions in the event of a default as defined in the Credit Agreement. As of December 31, 2017, the Partnership was in compliance with these covenants.

12. Related Party Transactions

The General Partner charges the Partnership for the reimbursements of employee costs and related employee benefits and other overhead costs supporting the Partnership's operations which amounted to $97.3 million, $90.3 million and $98.9 million for the years ended December 31, 2017, 2016 and 2015, respectively. Amounts due to the General Partner were $12.9 million and $15.5 million as of December 31, 2017 and 2016, respectively. Through the General Partner, the Partnership participates in the Parent's pension and other post-retirement benefits. (see Note 15).

13. Other Obligations

	As of December 31, 2017	2016
Deferred consideration	$23,966	$—
Contingent consideration	7,855	—
Port Authority terminal obligations	7,056	7,305
Postretirement benefits	2,412	3,671
Other	8,336	5,979
Other obligations, less current portion	$49,625	$16,955

Deferred Consideration - Carbo Terminals

In connection with the Carbo acquisition entered into during 2017, the Partnership is obligated to pay to Carbo a total of $38.2 million in equal monthly installments of $0.3 million payable over a ten year period. The obligation was recorded at an estimated fair value of $27.3 million using a discount rate of 7.1%. The short-term portion of this obligation as of December 31, 2017 is $2.0 million and is included in the current portion of other obligations. Deferred consideration obligation maturities for each of the next five years and thereafter as of December 31, 2017 are as follow:

2018	$3,818
2019	3,818
2020	3,818
2021	3,818
2022	3,818
Thereafter	16,546
Total	35,636
Less amount representing interest	(9,632)
Present value of payments	26,004
Less current portion	(2,038)
	$23,966

Contingent Consideration - Coen Energy

In connection with the Coen Energy acquisition entered into during 2017, the Partnership may be obligated to pay contingent consideration of up to $12.0 million during the three year period following the acquisition. The contingent consideration represents a liability recognized at fair value as of the acquisition date with subsequent fair value adjustments at each reporting period to be recorded in operations. At December 31, 2017 the estimated fair value of this obligation is $9.7 million. The short-term portion of this obligations of $1.9 million as of December 31, 2017, is included in the current portion of other obligations and represents an estimate of the expected future payment for 2018. See Note 2, Acquisitions and Note 17, Financial Instruments and Off-Balance Sheet Risk for additional information regarding the Partnership's contingent consideration obligation.

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Port Authority Terminal Obligations

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 at December 31, 2017 and $0.6 million at December 21, 2016 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.

Post Retirement Benefits

Postretirement benefit obligations are comprised of actuarially determined postretirement healthcare, life insurance and other postretirement benefits. See Note 15.

Asset Retirement Obligation

As of December 31, 2017, the other category in the table above includes the long-term portion of an asset retirement obligation (“ARO”) that relates to an environmental obligation associated with the purchase of a terminal in Bridgeport, Connecticut. The obligation was recorded in 2017 when the obligation was determinable. As of December 31, 2017 the short-term portion of the ARO is $0.7 million and represents the estimated obligation retirements for the ensuing year.

The changes in the ARO are as follows:

	2017
ARO - beginning of period	$—
Accrue fair value of ARO	3,662
Change in estimates	785
Accretion expense	63
Retirement of ARO	(20)
ARO - end of period	$4,490

14. Income Taxes

The Partnership is generally not subject to U.S. federal and state income tax with the exception of the Partnership's subsidiary Sprague Energy Solutions, Inc. The Partnership's Canadian operations are subject to Canadian federal and provincial income taxes. The income tax provision (benefit) attributable to operations is summarized as follows:

	Years Ended December 31,		
	2017	2016	2015
Current			
U.S. Federal income tax	$120	$229	$162
State and local income tax	231	1,199	1,072
Foreign income taxes	2,614	293	435
Total current income tax provision	2,965	1,721	1,669
Deferred			
U.S. Federal income tax	3	(9)	39
State and local income tax	(188)	(388)	(48)
Foreign income taxes	1,042	784	156
Total deferred income tax provision	857	387	147
Total income tax provision	$3,822	$2,108	$1,816

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U.S. and international components of income before income taxes were as follows:

	Years Ended December 31,		
	2017	2016	2015
United States	$18,517	$8,385	$77,993
Foreign	14,802	3,889	2,171
Total income before income taxes	$33,319	$12,274	$80,164

Reconciliations of the statutory U.S. federal income tax to the effective income tax for operations are as follows:

	Years Ended December 31,		
	2017	2016	2015
Statutory U.S. Federal income tax at 35%	$11,661	$4,296	$28,058
Partnership income not subject to tax	(6,360)	(2,691)	(27,076)
State and local income taxes, net of federal tax	46	787	1,003
Foreign earnings taxed at lower rates	(1,525)	(284)	(169)
Total income tax provision	$3,822	$2,108	$1,816

The components of the deferred tax assets (liabilities) were as follows:

	As of December 31,	
	2017	2016
Deferred tax assets (liabilities)		
Depreciation and amortization	(18,065)	(19,004)
Other differences, net	908	3,996
Valuation allowance	(466)	(473)
Net deferred tax liabilities	$(17,623)	$(15,481)

The Partnership's Canadian subsidiary had a net operating loss carryforward of $7.0 million as of December 31, 2016, which was fully utilized in the year ended December 31, 2017.

As of December 31, 2017, the Partnership has not provided deferred Canadian withholding taxes on accumulated Canadian earnings of $29.6 million which are considered to be indefinitely reinvested outside the U.S. The unrecognized deferred withholding tax liability associated with these earnings is $7.4 million as of December 31, 2017.

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").

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 U.S. 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 $1.1 million, $1.0 million and $1.4 million during the years ended December 31, 2017, 2016 and 2015, 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

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Partnership made total contributions to these plans of $5.0 million, $4.5 million and $4.6 million during the years ended December 31, 2017, 2016 and 2015, 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 $0.3 million during the years ended December 31, 2017, 2016 and 2015, for all periods, related to these plans.

16. Segment Reporting

The Partnership has four reporting segments that comprise the structure used by the chief operating decision makers (CEO and CFO/COO) to make key operating decisions and assess performance. When establishing a reporting segment, the Partnership aggregates individual operating units that are in the same line of business and have similar economic characteristics such as adjusted gross margin. These reporting segments are refined products, natural gas, materials handling and other activities.

The Partnership's refined products reporting 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. 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, drill sites, large industrial companies, real estate management companies, hospitals and educational institutions. The refined products reporting segment consists of three operating units.

The Partnership's natural gas reporting segment purchases natural gas from natural gas producers and trading companies and sells and distributes natural gas to commercial and industrial customers primarily in the Northeast and Mid-Atlantic United States. The natural gas reporting segment consists of one operating unit.

The Partnership's materials handling reporting segment offloads, stores, and/or prepares for delivery a variety of customer-owned products, including asphalt, clay slurry, salt, gypsum, crude oil, residual fuel oil, coal, petroleum coke, caustic soda, tallow, pulp and heavy equipment. These services are fee-based activities which are generally conducted under multi-year agreements. The materials handling reporting segment consists of two operating units.

The Partnership's other reporting segment includes the purchase, sale and distribution of coal, commercial trucking activities unrelated to its refined products segment and a heating equipment service business. Other activities are not reported separately as they represent less than 10% of consolidated net sales and adjusted gross margin. The other activities reporting segment consists of two operating units.

The Partnership evaluates segment performance based on adjusted gross margin, a non-GAAP measure, which is net sales less cost of products sold (exclusive of depreciation and amortization) increased by unrealized hedging losses and decreased by unrealized hedging gains, in each case with respect to refined products and natural gas inventory, prepaid forward contracts and natural gas transportation contracts.

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.

For the year ended December 31, 2017, we had two customers who represented 26% of net sales for our materials handling segment, although no customer represented more than 1% of our total net sales.

The Partnership had no single customer that accounted for more than 10% of total net sales for the years ended December 31, 2017, 2016 and 2015, respectively. The Partnership’s foreign sales, primarily sales of refined products, asphalt and natural gas to its customers in Canada, were $265.7 million, $196.4 million and $207.7 million for the years ended December 31, 2017, 2016 and 2015, respectively.

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Summarized financial information for the Partnership's reportable segments is presented in the table below:

	Years Ended December 31,		
	2017	2016	2015
Net sales:			
Refined products	$2,455,577	$1,988,597	$3,063,858
Natural gas	331,669	334,003	347,453
Materials handling	46,513	45,734	45,570
Other operations	21,237	21,664	25,033
Net sales	$2,854,996	$2,389,998	$3,481,914
Adjusted gross margin (1):			
Refined products	$142,467	$142,581	$170,448
Natural gas	65,060	62,435	51,004
Materials handling	46,512	45,712	45,564
Other operations	7,658	8,545	8,986
Adjusted gross margin	261,697	259,273	276,002
Reconciliation to operating income (2):			
Add: unrealized (loss) gain on inventory derivatives (3)	(124)	(31,304)	(2,079)
Add: unrealized gain (loss) on prepaid forward contract derivatives (4)	1,076	1,552	(2,628)
Add: unrealized (loss) gain on natural gas transportation contracts (5)	(10,441)	(18,612)	21,695
Operating costs and expenses not allocated to operating segments:			
Operating expenses	(72,284)	(65,882)	(71,468)
Selling, general and administrative	(87,582)	(84,257)	(94,403)
Depreciation and amortization	(28,125)	(21,237)	(20,342)
Operating income	64,217	39,533	106,777
Other (expense) income	108	(114)	298
Interest income	339	388	456
Interest expense	(31,345)	(27,533)	(27,367)
Income tax provision	(3,822)	(2,108)	(1,816)
Net income	$29,497	$10,166	$78,348

(1) The Partnership trades, purchases, stores and sells energy commodities that experience market value fluctuations. To manage the Partnership's underlying performance, including its physical and derivative positions, management utilizes adjusted gross margin, which is a non-GAAP financial measure. Adjusted gross margin is also used by external users of the Partnership's consolidated financial statements to assess the Partnership's economic results of operations and its commodity market value reporting to lenders. In determining adjusted gross margin, the Partnership adjusts its segment results for the impact of unrealized hedging gains and losses with regard to refined products and natural gas inventory, prepaid forward contracts and natural gas transportation contracts, which are not marked to market for the purpose of recording unrealized gains or losses in net income. These adjustments align the unrealized hedging gains and losses to the period in which the revenue from the sale of inventory, prepaid fixed forwards and the utilization of transportation contracts relating to those hedges is realized in net income. Adjusted gross margin has no impact on reported volumes or net sales.

(2) Reconciliation of adjusted gross margin to operating income, the most directly comparable GAAP measure.

(3) Inventory is valued at the lower of cost or net realizable value. The fair value of the derivatives the Partnership uses to economically hedge its inventory declines or appreciates in value as the value of the underlying inventory appreciates or declines, which creates unrealized hedging (losses) gains with respect to the derivatives that are included in net income.

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(4) The unrealized hedging gain (loss) on prepaid forward contract derivatives represents the Partnership's estimate of the change in fair value of the prepaid forward contracts which are not recorded in net income until the forward contract is settled in the future (i.e., when the commodity is delivered to the customer). As these contracts are prepaid, they do not qualify as derivatives and changes in the fair value are therefore not included in net income. The fair value of the derivatives the Partnership uses to economically hedge its prepaid forward contracts declines or appreciates in value as the value of the underlying prepaid forward contract appreciates or declines, which creates unrealized hedging gains (losses) that are included in net income.

(5) The unrealized hedging (loss) gain on natural gas transportation contracts represents the Partnership's estimate of the change in fair value of the natural gas transportation contracts which are not recorded in net income until the transportation is utilized in the future (i.e., when natural gas is delivered to the customer), as these contracts do not qualify as derivatives. As the fair value of the natural gas transportation contracts decline or appreciate, the offsetting physical or financial derivative will also appreciate or decline creating unmatched unrealized hedging (losses) gains in net income as of each period end.

Segment Assets

Due to the commingled 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, 2015	Activity (1)	As of December 31, 2016	Activity (1)	As of December 31, 2017
Refined products	$ 36,550	$ —	$ 36,550	$ 34,895	$ 71,445
Natural gas	18,626	7,262	25,888	9,592	35,480
Materials handling	6,896	—	6,896	—	6,896
Other	1,216	—	1,216	—	1,216
Total	$ 63,288	$ 7,262	$ 70,550	$ 44,487	$ 115,037

(1) Reflects goodwill attributable to business acquisitions. See Note 2.

Long-lived Assets

Long-lived assets (exclusive of intangible and other assets, net, and goodwill) classified by geographic location were as follows:

	As of December 31, 2017	2016
United States	$ 273,374	$ 170,841
Canada	76,685	80,260
Total	$ 350,059	$ 251,101

17. Financial Instruments and Off-Balance Sheet Risk

As of December 31, 2017 and 2016, the carrying amounts of cash, cash equivalents, accounts receivable, accounts payable and accrued liabilities approximated fair value because of the short maturity of these instruments. As of December 31, 2017 and 2016, the carrying value of the Partnership's margin deposits with brokers approximates fair value and consists of 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. As of December 31, 2017 and 2016, the carrying value of the Partnership's debt approximated fair value due to the variable interest nature of these instruments.

The Partnership's deferred consideration was recorded in connection with an acquisition on April 18, 2017 using an estimated fair value discount at the time of the transaction. As of December 31, 2017, the carrying value of the deferred consideration approximated fair value due to the fact that there has been no significant subsequent change in the estimated fair value discount rate.

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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, 2017			
	Fair Value Measurement	Quoted Prices in Active Markets Level 1	Significant Other Observable Inputs Level 2	Significant Unobservable Inputs Level 3
Derivative assets:				
Commodity fixed forwards	$11,502	$—	$ 11,502	$ —
Commodity swaps and options	100,630	100,613	17	—
Commodity derivatives	112,132	100,613	11,519	—
Interest rate swaps	2,615	—	2,615	—
Total derivative assets	$114,747	$100,613	$ 14,134	$ —
Derivative liabilities:				
Commodity fixed forwards	$61,195	$—	$ 61,195	$ —
Commodity swaps and options	103,827	103,654	173	—
Commodity derivatives	165,022	103,654	61,368	—
Interest rate swaps	6	—	6	—
Total derivative liabilities	$165,028	$103,654	$ 61,374	$ —
Contingent consideration	$9,725	$—	$ —	$ 9,725

	As of December 31, 2016			
	Fair Value Measurement	Quoted Prices in Active Markets Level 1	Significant Other Observable Inputs Level 2	Significant Unobservable Inputs Level 3
Derivative assets:				
Commodity fixed forwards	$65,618	$ —	$ 65,618	$ —
Commodity swaps and options	—	—	—	—
Commodity derivatives	65,618	—	65,618	—
Interest rate swaps	1,240	—	1,240	—
Total derivative assets	$66,858	$ —	$ 66,858	$ —
Derivative liabilities:				
Commodity fixed forwards	$94,875	$ —	$ 94,875	$ —
Commodity swaps and options	103	—	103	—
Commodity derivatives	94,978	—	94,978	—
Interest rate swaps	336	—	336	—
Other	25	—	25	—
Total derivative liabilities	$95,339	$ —	$ 95,339	$ —

Derivative Instruments

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 maximum amount of loss due to credit risk that the Partnership would incur if its counterparties failed completely to perform according to the terms of the contracts, based on the net fair value of these financial instruments, was $28.3 million at December 31, 2017. Information related to these offsetting arrangements as of December 31, 2017 and 2016 is as follows:

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	As of December 31, 2017					
				Gross Amount Not Offset in the Balance Sheet		
	Gross Amounts of Recognized Assets/ Liabilities	Gross Amounts Offset in the Balance Sheet	Amounts of Assets/ Liabilities in Balance Sheet	Financial Instruments	Cash Collateral Posted	Net Amount
Commodity derivative assets	$112,132	$ —	$ 112,132	$ (86,493)	$ (4,303)	$21,336
Interest rate swap derivative assets	2,615	—	2,615	—	—	2,615
Fair value of derivative assets	$114,747	$ —	$ 114,747	$ (86,493)	$ (4,303)	$23,951
Commodity derivative liabilities	$(165,022)	$ —	$ (165,022)	$ 86,493	$ 20,975	$(57,554)
Interest rate swap derivative liabilities	(6)	—	(6)	—	—	(6)
Fair value of derivative liabilities	$(165,028)	$ —	$ (165,028)	$ 86,493	$ 20,975	$(57,560)

	As of December 31, 2016					
				Gross Amount Not Offset in the Balance Sheet		
	Gross Amounts of Recognized Assets/ Liabilities	Gross Amounts Offset in the Balance Sheet	Amounts of Assets/ Liabilities in Balance Sheet	Financial Instruments	Cash Collateral Posted	Net Amount
Commodity derivative assets	$65,618	$ —	$ 65,618	$ (2,154)	$ (209)	$63,255
Interest rate swap derivative assets	1,240	—	1,240	—	—	1,240
Fair value of derivative assets	$66,858	$ —	$ 66,858	$ (2,154)	$ (209)	$64,495
Commodity derivative liabilities	$(94,978)	$ —	$ (94,978)	$ 2,154	$ —	$(92,824)
Interest rate swap derivative liabilities	(336)	—	(336)	—	—	(336)
Other	(25)	—	(25)	—	—	(25)
Fair value of derivative liabilities	$(95,339)	$ —	$ (95,339)	$ 2,154	$ —	$(93,185)

The following table presents total realized and unrealized gains (losses) on derivative instruments utilized for commodity risk management purposes included in cost of products sold (exclusive of depreciation and amortization):

	Years Ended December 31,		
	2017	2016	2015
Refined products contracts	$12,856	$(25,316)	$149,741
Natural gas contracts	(1,555)	7,153	19,824
Total	$11,301	$(18,163)	$169,565

There were no discretionary trading activities included in realized and unrealized gains (losses) on derivatives instruments for the years ended December 31, 2017, 2016 and 2015.

The following table presents the gross volume of commodity derivative instruments outstanding for the periods indicated:

	As of December 31, 2017		As of December 31, 2016	
	Refined Products (Barrels)	Natural Gas (MMBTUs)	Refined Products (Barrels)	Natural Gas (MMBTUs)
Long contracts	9,255	133,532	9,882	131,240
Short contracts	(13,487)	(72,074)	(13,940)	(76,556)

Interest Rate Derivatives

The Partnership has entered into interest rate swaps to manage its exposure to changes in interest rates on its Credit Agreement. The Partnership's interest rate 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.

The Partnership's interest rate swap agreements outstanding as of December 31, 2017 were as follows:

Interest Rate Swap Agreements

Beginning	Ending	Notional Amount
January 2017	January 2018	$225,000
January 2018	January 2019	$275,000
January 2019	January 2020	$175,000
January 2020	January 2021	$100,000
January 2021	January 2022	$100,000
January 2022	January 2023	$50,000

There was no material ineffectiveness determined for the cash flow hedges for the years ended December 31, 2017, 2016 and 2015.

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, 2017, the amount of unrealized gains, net of tax, expected to be reclassified to earnings during the following twelve-month period was $1.6 million.

Contingent Consideration

As part of the Coen Energy acquisition in 2017, the Partnership may be obligated to pay contingent consideration of up to $12.0 million if certain earnings objectives during the first three years following the acquisition are met. As of December 31, 2017, the estimated fair value of the contingent consideration was $9.7 million.

The estimated fair value of the contingent consideration arrangement described above is classified within Level 3 and was determined using an income approach based on probability-weighted discounted cash flows. Under this method, a set of discrete potential future earnings was determined using internal estimates based on various revenue growth rate assumptions for each scenario. A probability was assigned to each discrete potential future earnings estimate. The resulting probability-weighted contingent consideration amounts were discounted using a weighted average discount rate of 7.0%. Changes in either the revenue growth rates, related earnings or the discount rate could result in a material change to the amount of contingent consideration accrued and such changes will be recorded in the Partnership's consolidated statements of operations.

Changes in the contingent consideration liability measured at fair value on a recurring basis using unobservable inputs (Level 3) during fiscal 2017 are as follows:

Contingent consideration - beginning of period	$—
Accrued contingent consideration	9,557
Change in estimated fair value	168
Contingent consideration - end of period	$9,725

The Partnership recorded the increase in accrued contingent consideration set forth in the table above within selling, general and administrative expenses in the Partnership's Consolidated Statements of Operations.

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18. Commitments and Contingencies

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 2034 which are recorded as operating leases. Renewal options exist for a substantial portion of these leases. For operating leases, rental expense was $20.1 million, $21.9 million and $22.1 million for the years ended December 31, 2017, 2016 and 2015, respectively.

The following table summarizes the future minimum payments for the following five fiscal years for operating lease obligations as of December 31, 2017 with non-cancellable lease terms of one year or more:

2018	$12,177
2019	10,063
2020	4,353
2021	1,831
2022	1,478

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.

19. Equity and Equity-Based Compensation

Equity Awards - Annual Bonus Program

The board of directors of the General Partner has approved an annual bonus program which is provided to substantially all employees. Under this program bonuses for the majority of participants will be settled in cash with others receiving a combination of cash and common units. The Partnership records the expected bonus payment as a liability until a grant date has been established and awards finalized, which occurs in the first quarter of the year following the year for which the bonus is earned. The Partnership estimates that none of the annual bonus accrued as of December 31, 2017 will be settled in common units.

Of the annual bonus accrued as of December 31, 2016, approximately $0.4 million was subsequently settled by issuing 13,465 common units in 2017 (market value at settlement of $0.4 million) with 4,625 units being withheld from the recipients to satisfy tax withholding obligations. Of the annual bonus accrued as of December 31, 2015, approximately $5.0 million was subsequently settled by issuing 239,641 common units in 2016 (market value at settlement of $4.1 million) with 78,623 units being withheld from the recipients to satisfy tax withholding obligations.

Equity Awards - Director Compensation

During the years ended December 31, 2017, 2016, and 2015 the board of directors of the General Partner issued 9,360, 9,824, and 7,464 vested units as compensation to certain of its directors, respectively, with estimated grant date fair values of $0.2 million for each period.

Equity Awards - Other

On March 31, 2014, the board of directors of the General Partner granted 49,871 awards under the 2013 LTIP to certain directors and employees of the Partnership. Of these awards, 26,186 (estimated grant date fair value of $0.5 million) were granted as vested common units. In connection with these vested awards, the Partnership withheld from the recipients 6,768 units to satisfy tax withholding obligations. The remaining 23,685 awards (estimated grant date fair value of $0.5 million), consisted of phantom units issued to employees that vested as follows: 13,766 units on March 31, 2015 (with 4,851 units withheld to satisfy tax withholding requirements) and 9,919 on March 31, 2016 (with 3,705 units withheld to satisfy tax withholding requirements). Recipients had distribution equivalent rights on any phantom units that ultimately vested.

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On March 25, 2016, the board of directors of the General Partner granted 5,056 vested units (estimated grant date fair value of $0.1 million) to certain retiring employees of the Partnership. The Partnership withheld 1,384 units from the recipients to satisfy tax withholding obligations.

Equity Awards - Performance-based Phantom Units

The General Partner adopted the Sprague Resources LP 2013 Long-Term Incentive Plan (the "LTIP"), 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 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 LTIP, the total number of common units reserved and available for issuance under the LTIP will increase by 200,000 common units. As of December 31, 2017, there were 433,900 common units reserved for issuance and 194,967 available for issuance.

TUR-based Phantom Units

During the year ended December 31, 2015, the Partnership granted 141,000 TUR-based phantom units with an estimated grant date fair value of $4.5 million (average of $31.58 per unit) based on a Monte Carlo simulation performed using a weighted average volatility of 32.9%, and a weighted average risk free rate of 0.98%.

OCF-based Phantom Units

During the year ended December 31, 2016, the Partnership granted 166,900 OCF-based phantom units with a weighted average grant date fair value of $17.52 per unit and a performance period ending December 31, 2018.

During the year ended December 31, 2017, the Partnership granted 132,977 OCF-based phantom units with a weighted average grant date fair value of $26.62 per unit and a performance period ending December 31, 2019.

The number of OCF-based performance units that the Partnership estimates are probable to vest could change over the vesting period. Any such change in estimate is recognized as a cumulative adjustment to unit-based compensation expense calculated as if the new estimate had been in effect from the grant date.

Phantom units have vested as follows:

- TUR-based phantom units with a performance period ending as of December 31, 2017 vested at the 195.5% level and as a result 271,748 common units (vested market value of $7.0 million) were issued during January 2018 with 97,351 units being withheld to satisfy tax withholding requirements.
- TUR-based phantom units with a performance period ending as of December 31, 2016 vested at the 200% level and as a result 142,100 common units (vested market value of $3.9 million) were issued during January 2017 with 52,785 units being withheld to satisfy tax withholding requirements.
- TUR-based phantom units with a performance period ending as of December 31, 2015 vested at the 200% level and as a result 74,050 common units (vested market value of $1.4 million) were issued during January 2016 with 24,683 units being withheld to satisfy tax withholding obligations.
- TUR-based phantom units with a performance period ending as of December 31, 2014 vested at the 200% level and as a result 74,048 common units (vested market value of $1.8 million) were issued during January 2015 with 24,605 units being withheld to satisfy tax withholding obligations.

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The following table presents a summary of the status of the Partnership’s phantom unit awards subject to vesting:

	2017 (OCF-based)		2016 (OCF-based)		2015 (TUR-based)	
	Units	Weighted Average Grant Date Fair Value (per unit)	Units	Weighted Average Grant Date Fair Value (per unit)	Units	Weighted Average Grant Date Fair Value (per unit)
Nonvested at December 31, 2016	—	$ —	166,900	$ 17.52	141,000	31.58
Granted	132,977	26.62	—	—	—	$ —
Forfeited	(1,977)	(26.60)	(3,000)	$ (17.52)	(2,000)	(31.58)
Vested	—	$ —	—	$ —	(139,000)	(31.58)
Nonvested at December 31, 2017	131,000	$ 26.62	163,900	$ 17.52	—	$ —

Unit-based compensation recorded in unitholders’ equity for the years ended December 31, 2017, 2016 and 2015 was $2.2 million, $3.7 million, and $3.0 million respectively, and is included in selling, general and administrative expenses. Units issued under the Partnership’s 2013 LTIP are newly issued. Total unrecognized compensation cost related to the performance-based phantom units totaled $2.9 million as of December 31, 2017, which is expected to be recognized over a weighted average period of 11 months.

Equity - Changes in Partnership's Units

Pursuant to the terms of our partnership agreement, upon payment of the cash distribution on February 14, 2017, and meeting certain distribution and performance tests, the subordination period for our subordinated units expired on February 16, 2017. At the expiration of the subordination period, all 10,071,970 subordinated units converted into common units on a one-for-one basis.

The following table provides information with respect to changes in the Partnership’s unit:

	Common Units		
	Public	Sprague Holdings	Subordinated Units
Balance as of December 31, 2014	8,777,922	2,034,378	10,071,970
Units issued in connection with employee bonus	133,634	—	—
Units issued in connection with phantom and performance awards	58,358	—	—
Director vested awards	7,464	—	—
Balance as of December 31, 2015	8,977,378	2,034,378	10,071,970
Units issued in connection with employee bonus	161,018	—	—
Units issued in connection with phantom and performance awards	55,581	—	—
Employee and Director vested awards	13,496	—	—
Balance as of December 31, 2016	9,207,473	2,034,378	10,071,970
Conversion of subordinated units	—	10,071,970	(10,071,970)
Units issued in connection with phantom and performance awards	89,315	—	—
Units issued in connection with employee bonus	8,840	—	—
Director vested awards	9,360	—	—
Units issued in connection with Carbo acquisition	1,131,551	—	—
Balance as of December 31, 2017	10,446,539	12,106,348	—

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20. Earnings Per Unit

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 ownership percentages, after giving effect to priority income allocations for incentive distributions, which are declared and paid following the close of each quarter. 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 (loss) allocations used in the calculation of earnings per unit. Quarterly net income per limited partner and per unit amounts are stand-alone calculations and may not be additive to year to date amounts due to rounding and changes in outstanding units.

In addition to the common and subordinated units, the Partnership has also identified the IDRs 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 phantom units. Basic and diluted earnings (losses) per unit applicable to subordinated limited partners are the same because there were no potentially dilutive subordinated units outstanding.

The table below shows the weighted average common units outstanding used to compute net income per common unit for the periods indicated.

	Years Ended December 31,		
	2017	2016	2015
Weighted average limited partner common units - basic	22,208,964	11,202,427	10,975,941
Dilutive effect of unvested phantom units	265,908	358,190	165,392
Weighted average limited partner common units - dilutive	22,474,872	11,560,617	11,141,333

On February 16, 2017, all 10,071,970 subordinated units outstanding converted to common units. The Partnership did not allocate any earnings or loss to the subordinated unitholders for the year ended December 31, 2017, since the subordinated units did not share in the distribution of cash generated during 2017. The following tables provide a reconciliation of net income and the assumed allocation of net income to the limited partners' interest for purposes of computing net income per unit during periods prior to the conversion of the subordinated units:

	Year Ended December 31, 2016			
	Common	Subordinated	IDR	Total
	(in thousands, except per unit amounts)			
Net income				$10,166
Distributions declared	$24,998	$ 22,358	$1,742	$49,098
Assumed net income from operations after distributions	(20,562)	(18,370)	—	(38,932)
Assumed net income to be allocated	$4,436	$ 3,988	$1,742	$10,166
Income per unit - basic	$0.40	$ 0.40		
Income per unit - diluted	$0.38	$ 0.40		

	Year Ended December 31, 2015			
	Common	Subordinated	IDR	Total
	(in thousands, except per unit amounts)			
Net income				$78,348
Distributions declared	$21,826	$ 19,943	$321	$42,090
Assumed net income from operations after distributions	18,863	17,395	—	36,258
Assumed net income to be allocated	$40,689	$ 37,338	$321	$78,348
Income per unit - basic	$3.71	$ 3.71		
Income per unit - diluted	$3.65	$ 3.71		

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21. Quarterly Financial Data (Unaudited)

	Year Ended December 31, 2017				
	First	Second	Third	Fourth	Total
	(in thousands, except for per unit amounts)				
Net sales	$917,807	$513,626	$491,393	$932,170	$2,854,996
Net income (loss)	64,499	(7,792)	(14,316)	(12,894)	29,497
Limited partners' interest in net income (loss)	63,757	(8,646)	(15,340)	(14,267)	25,504
Net income (loss) per limited partner unit: (1)					
Common-basic	$2.98	$(0.39)	$(0.68)	$(0.63)	$1.15
Common-diluted	$2.94	$(0.39)	$(0.68)	$(0.63)	$1.13

	Year Ended December 31, 2016				
	First	Second	Third	Fourth	Total
	(in thousands, except for per unit amounts)				
Net sales	$722,907	$477,487	$422,779	$766,825	$2,389,998
Net income (loss)	29,821	(9,745)	(8,794)	(1,116)	10,166
Limited partners' interest in net income (loss)	29,546	(10,126)	(9,282)	(1,714)	8,424
Net income (loss) per limited partner unit: (1)					
Common-basic	$1.39	$(0.48)	$(0.44)	$(0.08)	$0.40
Common-diluted	$1.38	$(0.48)	$(0.44)	$(0.08)	$0.38
Subordinated-basic and diluted	$1.39	$(0.48)	$(0.44)	$(0.08)	$0.40

(1) Quarterly net income (loss) per limited partner unit amounts are stand-alone calculations and may not be additive to full year amounts due to rounding and changes in outstanding units.

22. Partnership Distributions

The Partnership's 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. Payments made in connection with DERs are recorded as a distribution.

Cash distributions for the periods indicated were as follows:

			Cash Distributed				
For the Quarter Ended	Distribution Date	Per Unit	Common	Subordinated	IDR	DER	Total
December 31, 2015	February 12, 2016	$0.5175	$5,724	$ 5,212	$167	$258	$11,361
March 31, 2016	May 13, 2016	$0.5325	$5,981	$ 5,363	$275	$—	$11,619
June 30, 2016	August 12, 2016	$0.5475	$6,150	$ 5,515	$381	$—	$12,046
September 30, 2016	November 14, 2016	$0.5625	$6,324	$ 5,665	$488	$—	$12,477
December 31, 2016	February 14, 2017	$0.5775	$6,544	$ 5,817	$597	$802	$13,760
March 31, 2017	May 15, 2017	$0.5925	$13,357	$ —	$742	$—	$14,099
June 30, 2017	August 11, 2017	$0.6075	$13,696	$ —	$854	$—	$14,550
September 30, 2017	November 13, 2017	$0.6225	$14,039	$ —	$1,024	$—	$15,063

In addition, on January 26, 2018, the Partnership declared a cash distribution for the three months ended December 31, 2017, of $0.6375 per unit, totaling $15.9 million (including a $1.4 million IDR distribution). Such distributions were paid on February 12, 2018, to unitholders of record on February 6, 2018.