

MAGELLAN MIDSTREAM PARTNERS LP
Form 10-K
February 15, 2019

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K
(Mark One)

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
 OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2018

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

Commission file number 1-16335
Magellan Midstream Partners, L.P.
(Exact name of registrant as specified in its charter)

Delaware 73-1599053
(State or other jurisdiction of (I.R.S. Employer
incorporation or organization) Identification No.)

Magellan GP, LLC 74121-2186
P.O. Box 22186, Tulsa, Oklahoma
(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code: (918) 574-7000
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 partnership 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

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

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405) 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 an 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 Accelerated filer Non-accelerated filer Smaller reporting company Emerging growth company

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 Act). Yes No

The aggregate market value of the registrant's voting and non-voting limited partner units held by non-affiliates computed by reference to the price at which the limited partner units were last sold as of June 29, 2018 was \$15,722,880,037.

As of February 14, 2019, there were 228,403,428 limited partner units outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's Proxy Statement prepared for the solicitation of proxies in connection with the 2019 Annual Meeting of Limited Partners are to be incorporated by reference in Part III of this Form 10-K.

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MAGELLAN MIDSTREAM PARTNERS, L.P.

FORM 10-K

PART I

Item 1. Business

(a) General Development of Business

Unless indicated otherwise, the terms “our,” “we,” “us” and similar language refer to Magellan Midstream Partners, L.P. together with its subsidiaries. Magellan Midstream Partners, L.P. is a Delaware limited partnership formed in August 2000 and its limited partner units are traded on the New York Stock Exchange under the ticker symbol “MMP.” Magellan GP, LLC, a wholly-owned Delaware limited liability company, serves as its general partner.

Sale of Interest in BridgeTex. In September 2018, we sold a 20% interest in BridgeTex Pipeline Company, LLC (“BridgeTex”) to an affiliate of OMERS Infrastructure Management Inc., which reduced our ongoing ownership in BridgeTex to a 30% interest. We continue to serve as the operator of BridgeTex.

(b) Financial Information About Segments

See Part II – Item 8. Financial Statements and Supplementary Data, Note 15 – Segment Disclosures.

(c) Narrative Description of Business

We are principally engaged in the transportation, storage and distribution of refined petroleum products and crude oil. As of December 31, 2018, our asset portfolio consisted of:

our refined products segment, comprised of our approximately 9,700-mile refined products pipeline system with 53 terminals as well as 25 independent terminals not connected to our pipeline system and our 1,100-mile ammonia pipeline system;

our crude oil segment, comprised of approximately 2,200 miles of crude oil pipelines, a condensate splitter and 33 million barrels of aggregate storage capacity, of which 21 million barrels are used for contract storage. Approximately 1,000 miles of these pipelines, the condensate splitter and 28 million barrels of this storage capacity (including 19 million barrels used for contract storage) are wholly-owned, and the remainder is owned through joint ventures; and

our marine storage segment, consisting of six marine terminals located along coastal waterways with an aggregate storage capacity of approximately 27 million barrels. Five of these terminals and approximately 25 million barrels of this storage capacity are wholly-owned, and the remainder is owned through joint ventures.

Industry Background

The United States (“U.S.”) petroleum products transportation and distribution system links sources of crude oil supply with refineries and ultimately with end users of petroleum products. This system is comprised of a network of pipelines, terminals, storage facilities, waterborne vessels, railcars and trucks. For transportation of petroleum products, pipelines are generally the most reliable, lowest cost and safest alternative for intermediate and long-haul movements between different markets. Throughout the distribution system, terminals play a key role in facilitating product movements by providing storage, distribution, blending and other ancillary services.

Terminology common in our industry includes the following terms, which describe products that we transport, store and distribute through our petroleum pipelines and terminals:

refined products are the output from refineries and are primarily used as fuels by consumers. Refined products include gasoline, diesel fuel, aviation fuel, kerosene and heating oil. Collectively, diesel fuel, kerosene and heating oil are referred to as distillates;

liquefied petroleum gases or LPGs are produced as by-products of the crude oil refining process and in connection with natural gas production. LPGs include butane and propane;

blendstocks are blended with refined products to change or enhance their characteristics such as increasing a gasoline's octane or oxygen content. Blendstocks include alkylates, oxygenates and natural gasoline;

heavy oils and feedstocks are used as burner fuels or feedstocks for further processing by refineries and petrochemical facilities. Heavy oils and feedstocks include No. 6 fuel oil and vacuum gas oil;

crude oil, which includes condensate, is used as feedstock by refineries, splitters and petrochemical facilities; and

biofuels, such as ethanol and biodiesel, are typically blended with other refined products as required by government mandates.

We use the term petroleum products to describe any, or a combination, of the above-noted products.

Description of Our Businesses

REFINED PRODUCTS

Our refined products segment consists of our refined products pipeline system, independent terminals and ammonia pipeline system. Our refined products pipeline system is the longest common carrier pipeline system for refined products and LPGs in the U.S., extending approximately 9,700 miles from the Texas Gulf Coast and covering a 15-state area across the central U.S. The system includes approximately 45 million barrels of aggregate usable storage capacity at 53 connected terminals. Our network of independent terminals includes 25 refined products terminals with 6 million barrels of storage located primarily in the southeastern U.S. and connected to third-party common carrier interstate pipelines, including the Colonial and Plantation pipelines. Our 1,100-mile common carrier ammonia pipeline system extends from production facilities in Texas and Oklahoma to terminals in agricultural demand centers in the Midwest.

Our refined products segment accounted for the following percentages of our consolidated revenue, operating margin and total assets:

	Year Ended		
	December 31,		
	2016	2017	2018
Percent of consolidated revenue	71%	72%	72%
Percent of consolidated operating margin	57%	58%	58%
Percent of consolidated total assets	49%	47%	48%

See Note 15—Segment Disclosures in the accompanying consolidated financial statements in Item 8 for a description of the non-generally accepted accounting principles (“GAAP”) measure of operating margin and additional financial information about our refined products segment.

Operations. Transportation, Terminalling and Ancillary Services. During 2018, approximately 70% of the refined products segment's revenue (excluding product sales revenue) was generated from transportation tariffs on volumes shipped on our refined products pipeline system. These transportation tariffs vary depending upon where the product originates, where ultimate delivery occurs and any applicable discounts. All transportation rates and discounts are in

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published tariffs filed with the Federal Energy Regulatory Commission (“FERC”) or appropriate

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state agency. Included as part of these tariffs are charges for terminalling and storage of products at 31 of our pipeline system's 53 connected terminals. Revenue from terminalling and storage at the other 22 terminals on our refined products pipeline system is derived from privately negotiated rates. Under our tariffs, we are allowed to deduct prescribed quantities of the products our shippers transport on our pipelines, which are commonly referred to as "tender deductions," to compensate us for lost product during shipment due to metering inaccuracies, intermingling of products between batches (transmix), evaporation or other events that result in volume shortages during the shipment process. In return for these tender deductions, our customers receive a guaranteed delivery of the gross volume of products they ship with us, less the amount of our tender deductions, irrespective of the actual amount of product shortages we incur during the shipment process.

In 2018, the products transported on our refined products pipeline system were comprised of 56% gasoline, 36% distillates and 8% aviation fuel and LPGs. The operating statistics below reflect our refined products pipeline system's operations for the periods indicated:

	Year Ended December 31,		
	2016	2017	2018
Shipments (million barrels):			
Gasoline	275.4	295.5	286.9
Distillates	150.2	166.2	181.7
Aviation fuel	25.7	26.5	31.0
LPGs	10.4	9.9	11.0
Total shipments	461.7	498.1	510.6

Our refined products pipeline system generates additional revenue from providing pipeline capacity and tank storage services, as well as providing services such as terminalling, ethanol and biodiesel unloading and loading, additive injection, custom blending, laboratory testing and data services to shippers, which are performed under a mix of "as needed," monthly and long-term agreements.

Our independent terminals generate revenue primarily by charging fees based on the amount of product delivered through our facilities and from ancillary services such as additive injections and ethanol blending. Our ammonia pipeline system generates revenue primarily through transportation tariffs on volumes shipped.

Commodity-Related Activities. Substantially all of the transportation and throughput services we provide are for third parties, and we do not take title to their products. We do take title of products related to tender deductions, product overages and our butane blending and fractionation activities on our refined products pipeline system. The sales of these products generate product sales revenue.

Our butane blending activity primarily involves purchasing butane and blending it into gasoline, which creates additional gasoline available for us to sell. This activity is limited by seasonal changes in gasoline vapor pressure specification requirements and by the varying quality of the gasoline products delivered to us. When the differential between the cost of butane and the price of gasoline fluctuates, the product margin we earn from these activities is impacted. We hedge the economic margin from this blending activity by entering into forward physical or exchange-traded gasoline futures contracts at the time we purchase the related butane. These blending activities accounted for approximately 87% of the total product margin for the refined products segment during 2018.

We also operate three fractionators along our pipeline system that separate transmix, which is an unusable mixture of various refined products, into usable refined products. In addition to fractionating the transmix that results from our pipeline operations, we also purchase and fractionate transmix from third parties and sell the resulting products.

Product margin from commodity-related activities in our refined products segment was \$101.8 million, \$130.4 million and \$222.1 million for the years ended December 31, 2016, 2017 and 2018, respectively. The amount of margin we earn from these activities and related hedges fluctuates with changes in petroleum prices (see Note 12–

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Derivative Financial Instruments to the consolidated financial statements included in Item 8 of this report for further information regarding our hedging activities). Product margin is a non-GAAP financial measure, but its components are determined in accordance with GAAP. Product margin, which is calculated as product sales revenue less cost of product sales, is used by management to evaluate the profitability of our commodity-related activities. The components of product margin included in operating profit, the nearest GAAP measurement, is provided in Note 15—Segment Disclosures to the consolidated financial statements included in Item 8 of this report.

Joint Venture Activities. We own a 50% interest in Powder Springs Logistics, LLC (“Powder Springs”), which was formed to construct and develop a butane blending system near Atlanta, Georgia. Powder Springs began operations in 2017.

Markets and Competition. Shipments originate on our refined products pipeline system from direct connections to refineries or through interconnections with other pipelines or terminals for transportation and ultimate distribution to retail gasoline stations, truck stops, railroads, airports and other end users. Through direct refinery connections and interconnections with other interstate pipelines, our refined products system can access approximately 45% of U.S. refining capacity, and in particular is well-connected to Texas Gulf Coast and Mid-Continent refineries. Our system is dependent on the ability of refiners and marketers to meet the demand for those products in the markets they serve through their shipments on our pipeline system. According to January 2019 projections provided by the Energy Information Administration, the demand for refined products in the market areas served by our pipeline system, primarily the West North Central and West South Central census districts, is expected to remain relatively stable over the next 10 years. As a result of its extensive connections to multiple refining regions, our pipeline system is well positioned to accommodate demand or supply shifts that may occur.

In 2018, approximately 63% of the products transported on our refined products pipeline system originated from 19 direct refinery connections and 37% originated from connections with other pipelines or terminals.

Our system is directly connected to and receives product from the following refineries:

Major Origins—Refineries (Listed Alphabetically)

Company	Refinery Location
CHS	McPherson, KS
CVR Energy	Coffeyville, KS
CVR Energy	Wynnewood, OK
Flint Hills Resources	Pine Bend, MN
HollyFrontier	El Dorado, KS
HollyFrontier	Tulsa, OK
HollyFrontier	Cheyenne, WY
Husky Energy	Superior, WI
Marathon	St. Paul, MN
Marathon	El Paso, TX
Marathon	Galveston Bay, TX
Marathon	Texas City, TX
Par Pacific	Newcastle, WY
Phillips 66	Ponca City, OK
Sinclair	Evansville, WY
Suncor Energy	Commerce City, CO
Valero	Ardmore, OK
Valero	Houston, TX

Valero

Texas City, TX

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Our system is also supplied by connections to multiple pipelines and terminals, including those shown in the table below:

Major Origins—Pipelines and Terminals (Listed Alphabetically)

Pipeline/Terminal	Connection Location	Source of Product
BP	Manhattan, IL	Whiting, IN refinery
CHS	Fargo, ND	Laurel, MT refinery
Explorer	Mt. Vernon, MO; Glenpool, OK; Dallas, TX; East Houston, TX	Various Gulf Coast refineries
Holly Energy Partners	Duncan, OK; El Paso, TX	Big Spring, TX refinery, Artesia, NM refinery
Kinder Morgan	Galena Park and Pasadena, TX	Various Gulf Coast refineries and imports
Magellan	Galena Park, TX	Various Gulf Coast refineries and imports
Mid-America (Enterprise)	El Dorado, KS	Conway, KS storage
NuStar Energy	Denver, CO; El Dorado, KS; Minneapolis, MN	Various OK & KS refineries, Mandan, ND refinery, McKee, TX refinery
ONEOK	Des Moines, IA; Wayne, IL; Plattsburg, MO	Bushton, KS storage and Chicago, IL area refineries
Phillips 66	Denver, CO; Kansas City, KS; Pasadena, TX; Casper, WY	Borger, TX refinery, various Billings, MT area refineries, Sweeney, TX refinery
Shell	East Houston, TX	Deer Park, TX refinery

In certain markets, barge, truck or rail provide an alternative source for transporting refined products; however, pipelines are generally the most reliable, lowest cost and safest alternative for refined products movements between different markets. As a result, our pipeline system's most significant competitors are other pipelines that serve the same markets.

Competition with other pipeline systems is based primarily on transportation charges, quality of customer service, proximity to end users and longstanding customer relationships. However, given the different supply sources on each pipeline, commodity prices at either the origin or terminal point on a pipeline may outweigh transportation costs when customers choose which pipeline to use.

Another form of competition for pipelines is the use of exchange agreements among shippers. Under these agreements, a shipper agrees to supply a market near its refinery or terminal in exchange for receiving supply from another refinery or terminal in a different market. These agreements allow the two parties to reduce the volumes transported and, therefore, the transportation fees paid to us. We compete with these alternatives through price incentives and through long-term commercial arrangements with potential exchange partners.

Government mandates increasingly require the use of renewable fuels, particularly ethanol. Due to technical and operational concerns, pipelines have generally not shipped ethanol, and most ethanol is transported by railroad, truck or barge. The increased use of ethanol has and will continue to compete with shipments on our pipeline system. However, our terminals have the necessary infrastructure to blend ethanol with refined products, and we earn revenue for these services.

Our independent terminals receive product primarily from the interstate pipelines to which they are connected and serve the retail, industrial and commercial sales markets along those pipelines. Demand for our services is driven primarily by end user demand for refined products in those markets. Our terminals compete with other

independent terminal operators as well as integrated oil companies on the basis of terminal location and versatility, services provided and price.

Our ammonia pipeline system receives product from ammonia production facilities in Texas and Oklahoma and delivers to agricultural markets in the Midwest, where the ammonia is used by farmers as a nitrogen fertilizer. During 2018, we made the decision to discontinue commercial operations of our ammonia pipeline beginning in late 2019 due to the system's low profitability and challenging economic outlook.

Customers and Contracts. Our refined products pipeline system provides services to several different types of customers, including refiners, wholesalers, retailers, traders, railroads, airlines and regional farm cooperatives. End markets for refined products deliveries are primarily retail gasoline stations, truck stops, farm cooperatives, railroad fueling depots, military bases and commercial airports. LPG shippers include wholesalers and retailers that, in turn, sell to commercial, industrial, agricultural and residential heating customers. Published tariffs serve as contracts, and shippers nominate the volume to be shipped up to a month in advance. In addition, we enter into agreements with shippers that commonly result in payment, volume or term commitments in exchange for reduced tariff rates or capital expansion commitments on our part. For 2018, approximately 40% of the shipments on our pipeline system were subject to these supplemental agreements. The average remaining life of these agreements was approximately three years as of December 31, 2018. While many of these supplemental agreements do not represent guaranteed volumes, they do reflect a significant level of shipper commitment to our refined products pipeline system.

For the year ended December 31, 2018, our refined products pipeline system had approximately 65 transportation customers. The top 10 shippers included independent refining companies, integrated oil companies, farm cooperatives and traders. Revenue attributable to these top 10 shippers for the year ended December 31, 2018 represented 32% of total revenue for our refined products segment and 55% of revenue excluding product sales.

Customers of our independent terminals include refiners, retailers, wholesalers and traders. Contracts vary in term and commitment and typically renew automatically, at the customer's option, at the end of each contract period.

Product sales are primarily to trading and marketing companies active in the markets we serve. These sales agreements are generally short-term in nature.

CRUDE OIL

Our crude oil segment is comprised of approximately 2,200 miles of crude oil pipelines, a condensate splitter and storage facilities with an aggregate storage capacity of approximately 33 million barrels, of which 21 million barrels are used for contract storage. Approximately 1,000 miles of these pipelines, the condensate splitter and 28 million barrels of this storage capacity (including 19 million barrels used for contract storage) are wholly-owned, and the remainder is owned through joint ventures.

The joint ventures in our crude oil segment are BridgeTex, Double Eagle Pipeline LLC ("Double Eagle"), HoustonLink Pipeline Company, LLC ("HoustonLink"), Saddlehorn Pipeline Company, LLC ("Saddlehorn") and Seabrook Logistics, LLC ("Seabrook").

Our crude oil segment accounted for the following percentages of our consolidated revenue, operating margin and total assets:

	Year Ended		
	December 31,		
	2016	2017	2018
Percent of consolidated revenue	20%	20%	22%

Percent of consolidated operating margin	32%	33%	34%
Percent of consolidated total assets	39%	38%	35%

See Note 15—Segment Disclosures in the accompanying consolidated financial statements in Item 8 for additional financial information about our crude oil segment.

Operations. Our crude oil assets are strategically located to serve crude oil supply, trading and demand centers. Revenue is generated primarily through transportation tariffs on our crude oil pipelines, storage fees from our crude oil terminals and tolling fees from our condensate splitter. In addition, we earn revenue for ancillary services including terminal throughput fees. We generally do not take title to the products we ship or store for our crude oil customers. Our tariffs provide for tender deductions to compensate us for lost product during shipment due to metering inaccuracies, evaporation or other events that result in volume losses during the shipment process, and we take title to these products.

The approximately 450-mile Longhorn pipeline has the capacity to transport up to 275,000 barrels per day (“bpd”) of crude oil from the Permian Basin in West Texas to Houston, Texas. Shipments originate on the Longhorn pipeline in Crane, Barnhart or Midland, Texas via trucks or interconnections with crude oil gathering systems owned by third parties and are delivered to our terminal at East Houston or to various points on the Houston Ship Channel, including multiple refineries connected to our Houston distribution system.

Our East Houston terminal includes approximately nine million barrels of crude oil storage, with approximately five million barrels used for contract storage and four million barrels dedicated to the operation of the Longhorn and BridgeTex pipelines. (See discussion of our BridgeTex joint venture under Joint Venture Activities below.) Our East Houston terminal is also connected to our Houston distribution system and to third-party pipelines, including the Zydeco pipeline. Argus’ West Texas Intermediate (“WTI”) Houston price assessment is based on trades at the terminal, and the terminal is one of the delivery points for the Permian WTI Crude Oil futures contract traded on the Intercontinental Exchange.

Our Houston distribution system consists of more than 100 miles of pipeline that connect our East Houston terminal through several interchanges to various points, including multiple refineries throughout the Houston area and crude oil import and export facilities, including through the facility owned by Seabrook discussed below. In addition, it is directly connected to other third-party crude oil pipelines providing us access to crude oil from the Permian and Eagle Ford basins, the strategic crude oil trading hub in Cushing, Oklahoma and crude oil imports.

Our Cushing terminal consists of approximately 13 million barrels of crude oil storage, all of which is used for contract storage. The facility primarily receives and distributes crude oil via the multiple common carrier pipelines that terminate in and originate from the Cushing crude oil trading hub, including our Saddlehorn joint venture discussed below, as well as short-haul pipeline connections with neighboring crude oil terminals.

We own approximately 400 miles of pipeline in Kansas and Oklahoma used for crude oil service. A portion of these pipelines are leased to third parties, and we earn revenue from these pipeline segments for capacity reserved even if not used by the customers.

Our Corpus Christi terminal includes approximately two million barrels of condensate storage, with a portion used for contract storage and a portion used in conjunction with our Double Eagle joint venture discussed below. These assets receive product primarily from trucks, barges and pipelines that connect to our terminal for further distribution to end users by pipeline or waterborne vessels. Our 50,000 bpd condensate splitter with approximately two million barrels of related storage is also located at our terminal in Corpus Christi.

Joint Venture Activities. We own a 30% interest in BridgeTex, a joint venture with an affiliate of Plains All American Pipeline, L.P. (“Plains”) and an affiliate of OMERS Infrastructure Management Inc. BridgeTex owns an approximately 400-mile pipeline currently capable of transporting up to 440,000 bpd of Permian Basin crude oil from

Midland and Colorado City, Texas to our East Houston terminal. We receive management fees to operate BridgeTex. We have a long-term lease agreement with BridgeTex to provide it with capacity on our Houston distribution system, and we receive capacity lease revenue from this agreement.

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We own a 50% interest in Double Eagle, a joint venture with an affiliate of Kinder Morgan, Inc. (“Kinder”) that transports condensate from the Eagle Ford basin in South Texas via an approximately 200-mile pipeline to our terminal in Corpus Christi or to an inter-connecting pipeline that transports product to the Houston area. An affiliate of Kinder serves as the operator of Double Eagle. We receive throughput revenue from Double Eagle.

We own a 50% interest in HoustonLink, a joint venture with an affiliate of TransCanada Corporation (“TransCanada”). HoustonLink owns a crude oil pipeline connecting TransCanada’s Houston tank terminal, which is a termination point for TransCanada’s Marketlink Pipeline, to our nearby East Houston terminal. We operate the HoustonLink pipeline and receive management fees.

We own a 40% interest in Saddlehorn, a joint venture with an affiliate of Plains and an affiliate of Anadarko Petroleum Corporation. Saddlehorn owns an undivided joint interest in an approximately 600-mile pipeline, which delivers various grades of crude oil from the DJ Basin as well as other Rocky Mountain production regions to storage facilities in Cushing, including our Cushing terminal. Saddlehorn has the capacity to deliver up to 190,000 bpd of crude oil. We receive management fees to operate Saddlehorn, and we also receive storage revenue from Saddlehorn.

We own a 50% interest in Seabrook, a joint venture with an affiliate of LBC Tank Terminals, LLC (“LBC”). Seabrook owns approximately two million barrels of crude oil storage located in Seabrook, Texas, a pipeline that connects Seabrook’s storage facilities to an existing third-party pipeline that transports crude oil to a Houston-area refinery and a pipeline connecting its facility to our Houston distribution system. We receive management fees for operating the pipeline activities of Seabrook. In addition, we have a long-term lease agreement with Seabrook that is utilized to provide our customers with crude oil storage capacity and dock access for crude oil imports and exports on the Texas Gulf Coast.

Markets and Competition. Market conditions experienced by our crude oil pipelines vary significantly by location. The Longhorn and BridgeTex pipelines deliver Permian Basin production to trading and demand centers in the Houston area, and consequently depend on the level of production in the Permian Basin for supply. Demand for shipments to the Houston area is driven primarily by the utilization of West Texas crude oil by Gulf Coast refineries and the price for crude oil on the Gulf Coast relative to its price in alternative markets, including export markets. Permian Basin production may vary based on numerous factors including overall crude oil prices and changes in costs of production, while Gulf Coast demand for Permian Basin production may change based on relative prices for competing crude oil or changes by refineries to their crude oil processing slates, as well as by overall domestic and international demand for petroleum products. The Longhorn and BridgeTex pipelines compete with alternative outlets for Permian Basin production, including pipelines that transport crude oil to the Cushing crude oil trading hub as well as other pipelines that currently transport or new pipelines that may transport Permian Basin crude to the Gulf Coast. These pipelines also compete with truck and rail alternatives for Permian Basin barrels. Further, these pipelines indirectly compete with other alternatives for delivering similar quality crude oil to the Gulf Coast, including pipelines from other producing regions such as the Mid-Continent, Bakken, Eagle Ford or Gulf of Mexico, as well as waterborne imports. Competition is based primarily on tariff rates, proximity to both supply sources and demand centers, connectivity, service offerings, crude quality and customer relationships.

Volumes on our Houston distribution system are driven by our customers’ demand for distribution of crude oil between our system’s various connections and as a result are affected in part by changes in origins and destinations of crude oil processed in or distributed through the Gulf Coast region. Our HoustonLink and Seabrook joint ventures offer our customers additional pipeline connectivity and crude oil storage in the Houston area. Our Houston distribution system competes with other distribution facilities in the Houston area based primarily on tariff rates, connectivity to supply sources and demand centers, customer service and customer relationships.

Our crude oil storage facilities in Cushing serve customers who value Cushing's location as an interchange point for numerous interstate pipelines, including Saddlehorn, and its status as a crude oil trading hub. Demand for crude oil storage in Cushing could be affected by changes in crude oil pipeline flows that change the volume of crude oil that flows through or is stored in Cushing, as well as by developments of alternative trading hubs that reduce Cushing's relative importance. In addition, demand for our storage services in Cushing could be affected by

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crude oil price volatility or price structures or by regulatory or financial conditions that affect the ability of our customers to store or trade crude oil. We compete in Cushing with numerous other storage providers, with competition based on a combination of connectivity, storage rates and other terms, customer service and customer relationships.

The Double Eagle pipeline depends on condensate production from the Eagle Ford basin for its supply and competes primarily with other pipelines and supply alternatives that are capable of transporting condensate from the Eagle Ford production area. Competition is based primarily on tariff rates, connectivity, customer service and customer relationships. The demand for Double Eagle's services could be affected by changes in Eagle Ford condensate production or changes in demand for different grades of condensate. Demand for our condensate storage at Corpus Christi is subject to similar market conditions and competitive forces.

Our condensate splitter at our Corpus Christi terminal depends on condensate production primarily from the Permian and Eagle Ford basins and overall demand for products derived from condensate. Our splitter competes with other facilities in the Gulf Coast region including other splitters and refineries, as well as export alternatives.

The Saddlehorn pipeline depends on crude oil production primarily from the DJ Basin and broader Rocky Mountain region for its supply and competes primarily with other pipelines and supply alternatives that are capable of transporting crude oil from the DJ Basin and Rocky Mountain production area. Competition is based primarily on tariff rates, connectivity, customer service and customer relationships. The demand for Saddlehorn's services could be affected by changes in DJ Basin crude oil production and additional investment in competing transportation alternatives out of the basin, as well as the status of Cushing as a crude oil trading hub. DJ Basin production may vary based on numerous factors including overall crude oil prices and changes in costs of production.

Customers and Contracts. We ship crude oil as a common carrier for several different types of customers, including crude oil producers, end users such as refiners, and marketing and trading companies. Published transportation tariffs filed with the FERC or the appropriate state agency serve as contracts to ship on our crude oil pipelines, and shippers nominate volumes to be transported up to a month in advance, with rates varying by origin, destination and product grade. We typically reserve at least 10% of the shipping capacity of our pipelines for spot shippers. Spot barrel movements on our pipelines generally ship at higher rates than those charged to committed shippers. Generally, we secure long-term commitments to support our long-haul crude oil pipeline assets. Specifically, with regard to our Longhorn pipeline, the vast majority of the volumes shipped on that system are supported by take-or-pay agreements. For 2018, approximately 40% of the shipments on our wholly-owned crude oil pipelines were subject to such commitments. The average remaining life of these contracts was approximately five years as of December 31, 2018. As of December 31, 2018, approximately 80% of our crude oil storage available for contract was under agreements with terms in excess of one year or that renew on an annual basis at our customers' option. The average remaining life of our storage contracts was approximately two years as of December 31, 2018. These agreements obligate the customer to pay for storage capacity reserved even if not used by the customer. BridgeTex, Double Eagle, Saddlehorn and Seabrook also have long-term contracts which support our capital investments in these joint ventures. Additionally, we have a tolling agreement with one customer for the exclusive use of our condensate splitter in Corpus Christi with a remaining life of approximately four years.

MARINE STORAGE

We own and operate six marine storage terminals located along coastal waterways with approximately 27 million barrels of aggregate storage capacity. Our joint venture assets include two million barrels of storage capacity with expansions currently underway for an additional four million barrels of storage. Our marine terminals provide distribution, storage, blending, inventory management and additive injection services for refiners, marketers, traders and other end users of petroleum products.

The joint ventures in our marine storage segment are MVP Terminalling, LLC (“MVP”) and Texas Frontera, LLC (“Texas Frontera”).

Our marine storage segment accounted for the following percentages of our consolidated revenue, operating margin and total assets:

	Year Ended		
	December 31,		
	2016	2017	2018
Percent of consolidated revenue	9%	8%	7%
Percent of consolidated operating margin	10%	8%	7%
Percent of consolidated total assets	12%	12%	14%

See Note 15—Segment Disclosures in the accompanying consolidated financial statements in Item 8 for additional financial information about our marine storage segment.

Operations. Our marine storage terminals generate revenue primarily through providing storage services for a variety of customers. Refiners and chemical companies typically use our storage terminals due to tankage constraints at their facilities or the specialized handling requirements of the stored product. We also provide storage services to marketers and traders that require access to significant storage capacity. Because the rates charged at these terminals are unregulated, the marketplace determines the prices we charge for our services. In general, we do not take title to the products that are stored in or distributed from our marine terminals.

Our Galena Park, Texas marine terminal is located along the Houston Ship Channel and is our largest marine facility with 13 million barrels of wholly-owned usable storage capacity. This facility stores a mix of refined products, blendstocks, heavy oils and crude oil, and receives and distributes products by pipeline, truck, rail, barge and ship. An advantage of our Galena Park facility is that it provides our customers with access to multiple common carrier pipelines, including our Houston distribution system, as well as deep-water port facilities that accommodate both ship and barge traffic and loading and unloading facilities for trucks and rail cars.

Our New Haven, Connecticut marine terminal is located on the Long Island Sound near the New York Harbor and has approximately four million barrels of usable storage capacity and handles heating oil, refined products, asphalt, ethanol and biodiesel. This facility receives and distributes products by pipeline, ship, barge and truck.

Our Marrero, Louisiana marine terminal is located on the Mississippi River and has approximately three million barrels of usable storage capacity. This facility handles heavy oils, distillates and asphalt. We receive products at our Marrero terminal by rail, ship and barge and deliver products from Marrero by rail, ship, barge and truck.

Our Wilmington, Delaware marine terminal is located at the Port of Wilmington along the Delaware River. The facility includes almost three million barrels of usable storage and handles refined products, ethanol, heavy oils and crude oil. We receive products at our Wilmington terminal by pipeline, ship and barge and deliver products from this facility by pipeline, truck, ship and barge.

Our Corpus Christi, Texas marine terminal is located near local refineries and petrochemical plants and includes almost two million barrels of usable storage capacity utilized for heavy oils and feedstocks. We receive and deliver products at our Corpus Christi facility primarily by ship, barge, truck and pipeline.

Joint Venture Activities. We own a 50% interest in Texas Frontera, which owns approximately one million barrels of storage at our Galena Park terminal. In addition to equity earnings, we receive a fee for operating Texas Frontera.

We own a 50% interest in MVP, which owns a refined products marine storage terminal along the Houston Ship Channel in Pasadena, Texas. The facility began operations in January 2019 with one million barrels of storage and a proprietary ship dock. An additional four million barrels of storage, truck loading facilities and a second ship dock are

expected to be operational by the end of 2019. We serve as construction manager and operator of MVP and receive management fees for our services.

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Markets and Competition. Our marine storage terminals compete with other terminals with respect to location, price, versatility and services provided. The competition primarily comes from integrated petroleum companies, refining and marketing companies, independent terminal companies and distribution companies with marketing and trading operations.

We believe the continued demand for storage and ancillary services at our marine terminals results from our cost-effective distribution services and key transportation links. The ancillary services we provide at our marine terminals, such as product heating, blending, mixing and additive injection, attract additional demand for our storage services and result in additional revenue opportunities. Demand can be influenced by projected changes in and volatility of petroleum product prices.

Customers and Contracts. We have long-standing relationships with refineries, suppliers and traders at our marine terminals. During 2018, approximately 87% of our storage terminal capacity was utilized with the remaining not utilized primarily due to tank integrity work throughout the year. As of December 31, 2018, approximately 93% of our usable storage capacity was under contract with an average remaining life of approximately two years. These contracts obligate the customer to pay for terminal capacity reserved even if not used by the customer.

GENERAL BUSINESS INFORMATION

Major Customers

No customer accounted for more than 10% of our consolidated revenues during 2016, 2017 or 2018.

Commodity Positions and Hedges

Our policy is generally to purchase only those products necessary to conduct our normal business activities. We do not acquire physical inventory, futures contracts or other derivative instruments for the purpose of speculating on commodity price changes. Our butane blending and fractionation activities result in our carrying significant levels of petroleum product inventories. In addition, we hold positions related to tender deductions and product overages. We use derivative instruments to hedge against commodity price changes and manage risks associated with our various commodity purchase and sale activities. Our risk management policies and procedures are designed to monitor our derivative instrument positions, as well as physical volumes, grades, locations, delivery schedules and storage capacity to help ensure that our hedging activities address the risks inherent in our commodity positions.

Regulation

Tariff Regulation. Our interstate common carrier petroleum products pipeline operations are subject to rate regulation by the FERC under the Interstate Commerce Act, the Energy Policy Act of 1992 and rules and orders promulgated pursuant thereto. FERC regulation requires that interstate liquids pipeline rates be filed with the FERC, be posted publicly and be nondiscriminatory and “just and reasonable.” Rate changes and the overall level of our rates may be subject to challenge by the FERC or shippers. If the FERC determines that our rates are not just and reasonable, we may be required to reduce our rates and pay refunds for up to two years of over-earning. The rates on approximately 40% of the shipments on our refined products pipeline system are regulated by the FERC primarily through an index methodology, which for the five-year period beginning July 1, 2016 is set at the annual change in the producer price index for finished goods (“PPI-FG”) plus 1.23%. As an alternative to cost-of-service or index-based rates, interstate liquids pipeline companies may establish rates by obtaining authority to charge market-based rates in competitive markets or by negotiation with unaffiliated shippers. Approximately 60% of our refined products pipeline system’s

markets are either subject to regulations by the states in which we operate or are approved for market-based rates by the FERC, and in both cases these rates can generally be adjusted at our discretion based on market factors. Most of the tariffs on our crude oil pipelines are established by negotiated rates

that generally provide for annual adjustments in line with changes in the FERC index, subject to certain modifications.

The Surface Transportation Board, a part of the U.S. Department of Transportation, has jurisdiction over interstate pipeline transportation and rate regulations of ammonia. Transportation rates must be reasonable, and a pipeline carrier may not unreasonably discriminate among its shippers.

In addition, some shipments on our pipeline systems move within a single state and thus are considered to be intrastate commerce. The rates, terms and conditions of service offered by our intrastate pipelines are subject to certain regulations with respect to such intrastate transportation by state regulatory authorities in the states of Colorado, Illinois, Kansas, Minnesota, Oklahoma, Texas and Wyoming. Such state regulatory authorities could limit our ability to increase our rates or to set rates based on our costs, or could order us to reduce our rates and require the payment of refunds to shippers if our rates are found to have been unjust.

Commodity Market Regulation. Our conduct in petroleum markets and in hedging our exposure to commodity price fluctuations must comply with laws and regulations that prohibit market manipulation.

Wholesale sales of petroleum are subject to provisions of the Energy Independence and Security Act of 2007 (“EISA”) and regulations by the Federal Trade Commission (“FTC”). Under the EISA, the FTC issued a rule that prohibits fraudulent or deceptive conduct (including false or misleading statements of material fact) in connection with wholesale purchases or sales of crude oil or refined products. The FTC rule also bans intentional failures to state a material fact when the omission makes a statement misleading and distorts, or is likely to distort, market conditions for any product covered by the rule. The FTC holds substantial enforcement authority under the EISA, including authority to request that a court impose fines of up to approximately \$1.2 million per day per violation.

Under the Commodity Exchange Act, the Commodity Futures Trading Commission (“CFTC”) is directed to prevent price manipulations for the commodities markets, including the physical energy, futures and swaps markets. Pursuant to the Dodd-Frank Act, the CFTC has adopted additional anti-market manipulation regulations that prohibit, among other things, fraud and price manipulation in the physical energy, futures and swaps markets. The CFTC also has statutory authority to assess fines of up to the greater of approximately \$1 million or triple the monetary gain for violations of its anti-market manipulation regulations.

The CFTC has re-proposed rules that would place federal limits on positions in certain futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. The CFTC has also finalized a companion rule on aggregation of positions among entities under common ownership or control, which is currently effective, but subject to certain no-action relief. If finalized, the position limits rule together with the final aggregation rule may have an impact on our ability to hedge our exposure to certain enumerated commodities. If we reduce our use of derivatives as a result of these regulations, our results of operations may become more volatile and our cash flows may be less predictable.

Renewable Fuel Standard. We are an obligated party under the Renewable Fuel Standard (“RFS”) promulgated by the Environmental Protection Agency (“EPA”) and are required to satisfy our Renewable Volume Obligation (“RVO”) on an annual basis. To meet the RVO, the gasoline products we produce in our butane blending activities must either contain the mandated renewable fuel components, or credits must be purchased to cover any shortfall. We met our RVO requirements for 2018 and expect to satisfy the requirements for 2019 mainly through the purchase of credits, known as Renewable Identification Numbers (“RINs”). As the RFS program is currently structured, the RVO of all obligated parties will increase over time unless adjusted by the EPA. The ability to incorporate increasing volumes of renewable fuel components into fuel products may be limited, which could increase our costs to comply with the RFS standards or limit our ability to blend.

Income Taxes. We are a partnership for income tax purposes and, therefore, are not subject to federal or state income taxes for most of the states in which we operate. The tax on our net income is borne by our limited partners through allocation to them of their share of our taxable income. Net income for financial statement purposes may differ significantly from taxable income allocated to unitholders because of differences between the tax basis and financial reporting basis of assets and liabilities and the taxable income allocation requirements under our

partnership agreement. The aggregate difference in the basis of our net assets for financial and tax reporting purposes cannot be readily determined because information regarding each partner's tax attributes is not available to us.

As a publicly traded limited partnership, we are subject to a statutory requirement that our "qualifying income" (as defined by the Internal Revenue Code, related Treasury Regulations and Internal Revenue Service pronouncements) exceed 90% of our total gross income, determined on a calendar year basis. If our qualifying income does not meet this statutory requirement, we could be taxed as a corporation for federal and state income tax purposes. For the years ended December 31, 2016, 2017 and 2018, our qualifying income met the statutory requirement.

Environmental, Maintenance, Safety & Security

General. The operation of our pipeline systems, terminals and associated facilities is subject to strict and complex laws and regulations relating to the protection of the environment and workplace safety. These bodies of laws and regulations govern many aspects of our business including the work environment, the generation and disposal of waste, discharge of process and storm water, air emissions, remediation requirements and facility design requirements to protect against releases into the environment. We believe our assets are designed, operated and maintained in material compliance with these laws and regulations and in accordance with other generally accepted industry standards and practices.

Environmental. Our estimates for remediation liabilities assume that we will be able to use traditionally acceptable remediation and monitoring methods, as well as associated engineering or institutional controls, to comply with applicable regulatory requirements. These estimates include the cost of performing environmental assessments, remediation and monitoring of the impacted environment such as soils, groundwater and surface water conditions. Our recorded environmental liabilities are estimates and total remediation costs may differ from current estimated amounts.

We may experience future releases of regulated materials into the environment or discover historical releases that were previously unidentified or not assessed. While an asset integrity and maintenance program designed to prevent, promptly detect and address releases is an integral part of our operations, damages and liabilities arising out of any environmental release from our assets identified in the future could have a material adverse effect on our results of operations, financial position or cash flow.

Liabilities recognized for estimated environmental costs were \$19.3 million and \$20.5 million at December 31, 2017 and 2018, respectively. Environmental liabilities have been classified as current or noncurrent based on management's estimates regarding the timing of actual payments. We have insurance policies that provide coverage for remediation costs and liabilities arising from sudden and accidental releases of products applicable to all of our assets. Receivables from insurance carriers related to environmental matters were \$7.2 million and \$4.1 million at December 31, 2017 and 2018, respectively.

Hazardous Substances and Wastes. Our operations are subject to various laws and regulations that relate to the release of hazardous substances and solid wastes into water or soils. For instance, the Comprehensive Environmental Response, Compensation and Liability Act, as amended ("CERCLA"), also known as the Superfund law, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons who are considered to be responsible for the release of a hazardous substance into the environment.

Our operations generate wastes, including hazardous wastes that are subject to the requirements of the Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. We are not currently required to comply with a substantial portion of the RCRA requirements as our operations routinely generate only small quantities of hazardous wastes, and we are not a hazardous waste treatment, storage or disposal facility operator that is required to

obtain a RCRA hazardous waste permit. While RCRA currently exempts a number of wastes from being subject to hazardous waste requirements, including many oil and gas exploration and production wastes, the

EPA could consider the adoption of stricter disposal standards for non-hazardous wastes. Moreover, it is possible that additional wastes, which could include non-hazardous wastes currently generated during operations, may be designated as hazardous wastes. Hazardous wastes are subject to more rigorous and costly storage and disposal requirements than non-hazardous wastes. Changes in the regulations could materially increase our expenses.

We own or lease properties where hydrocarbons have been handled for many years. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on, under or from the properties owned or leased by us or on or under other locations where these wastes have been taken for disposal. In addition, many of these properties were previously operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under our control. These properties and wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes, including wastes disposed of or released by prior owners or operators, to remediate contaminated property, including groundwater contaminated by prior owners or operators, or to make capital improvements to prevent future contamination.

Water Discharges. Our operations can result in the discharge of pollutants, including crude oil and refined products, and are subject to the Oil Pollution Act (“OPA”) and Clean Water Act (“CWA”). The OPA and CWA subject owners of facilities to strict, joint and potentially significant liability for removal costs and certain other consequences of a product spill such as natural resource damages, where the product spills into regulated waters, along federal shorelines or in the exclusive economic zone of the U.S. In the event of a product spill from one of our facilities into regulated waters, substantial liabilities could be imposed. States in which we operate have also enacted similar laws. The CWA imposes restrictions and strict controls regarding the discharge of pollutants into regulated waters. This law and comparable state laws require that permits be obtained to discharge pollutants into regulated waters and impose substantial potential liability for non-compliance. Compliance with these laws is not expected to have a material adverse effect on our business, financial position, results of operations or cash flows.

Air Emissions. Our operations are subject to the federal Clean Air Act (“CAA”) and comparable state and local laws and regulations, which regulate emissions of air pollutants from various industrial sources, including certain of our facilities, and impose various monitoring and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations and utilize specific emission control technologies to limit emissions. Failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations and, potentially, criminal enforcement actions. We may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. We believe, however, that our operations will not be materially adversely affected by such requirements.

Greenhouse Gas Emissions. The EPA has adopted regulations under existing provisions of the CAA that require certain large stationary sources to obtain pre-construction permits and operating permits for greenhouse gas emissions. In addition, in September 2009, the EPA issued a final rule requiring the monitoring and reporting of greenhouse gas emissions from certain large greenhouse gas emissions sources. This reporting rule was expanded in November 2010 to include petroleum facilities.

Federal and state legislative and regulatory initiatives, as well as those in other countries, may attempt to further address climate change or control or limit greenhouse gas emissions. Although it is not possible at this time to predict how they would impact our business, any such future laws or regulations could adversely affect demand for the products that we transport, store and distribute. Depending on the particular programs adopted, they could also increase our costs to operate and maintain our facilities by requiring that we measure and report our emissions, install new emission controls on our facilities, acquire allowances to authorize our emissions, pay any taxes related to our

emissions and administer and manage an emissions program, among other things. We may be unable to include some or all of such increased costs in the rates charged to our customers and any such recovery may depend on events beyond our control, including the outcome of future rate proceedings before the FERC or state regulatory agencies and the provisions of any final legislation or implementing regulations.

Finally, certain scientific studies conclude that increasing concentrations of greenhouse gases in the Earth's atmosphere may affect climate changes, which could result in the increased frequency and severity of storms, floods and other climatic events. If any such effects were to occur, there may be an increased potential for adverse effects on our assets and operations.

Maintenance. Our pipeline systems are subject to regulation by the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration ("PHMSA") under the Hazardous Liquid Pipeline Safety Act of 1979, as amended ("HLPESA"), and comparable state statutes relating to the design, installation, testing, construction, operation, replacement and management of our pipeline facilities. PHMSA develops, prescribes and enforces minimum federal safety standards for the transportation of hazardous liquids by pipeline. Congress also enacted the Pipeline Safety Act of 1992, which added the environment to the list of statutory factors that must be considered in establishing safety standards for hazardous liquid pipelines and mandated that regulations be issued to establish criteria for operators to use in identifying and inspecting pipelines located in "high consequence areas" or "HCAs," defined as those areas that are unusually sensitive to environmental damage, cross a navigable waterway or have a high population density. As an operator of hazardous liquid pipelines, we are required to and have developed and follow an integrity management program that provides for assessment of the integrity of all of the portions of our pipelines that could affect designated HCAs. In 1996, Congress enacted the Accountable Pipeline Safety and Partnership Act, which limited the operator identification requirement mandate to pipelines that cross a waterway where a substantial likelihood of commercial navigation exists, required that certain areas where a pipeline release would likely cause permanent or long-term environmental damage be considered in determining whether an area is unusually sensitive to environmental damage and mandated that regulations be issued for the qualification and testing of certain pipeline personnel. In the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006, Congress required mandatory inspections for certain U.S. crude oil transmission pipelines in HCAs and mandated that regulations be issued for low-stress hazardous liquid pipelines and pipeline control room management. Our assets are also subject to various federal security regulations, and we believe we are in substantial compliance with all applicable federal regulations.

In addition to regulations applicable to all of our pipelines, we have undertaken additional obligations to mitigate potential risks to health, safety and the environment on our Longhorn pipeline. Our compliance with these incremental obligations is subject to the oversight of the U.S. Department of Transportation through PHMSA.

States are largely preempted by federal law from regulating pipeline safety for interstate lines, but most states are certified by the U.S. Department of Transportation to assume responsibility for enforcing federal intrastate pipeline regulations and inspection of intrastate pipelines. States may adopt stricter standards for intrastate pipelines than those imposed by the federal government for interstate lines; however, states vary considerably in their authority and capacity to address pipeline safety. State standards may include requirements for facility design and management in addition to requirements for pipelines. We believe we are in substantial compliance with all applicable state regulations.

Our marine terminals along coastal waterways are subject to U.S. Coast Guard regulations and comparable state statutes relating to the design, installation, construction, testing, operation, replacement and management of these assets.

Breakout Storage Tank Integrity Regulations. In January 2015, amended regulations were published by PHMSA which require more frequent out-of-service inspections for breakout storage tanks. PHMSA approved our request for phased adoption of the amended regulations in May 2018. We do not anticipate that compliance with the amended regulations will have a material adverse effect on our business, financial position, results of operations or cash flows.

Safety. Our assets are subject to the requirements of the federal Occupational Safety and Health Act (“OSHA”) and comparable state statutes, which, among other things, require us to organize and disclose information about the hazardous materials used in our operations. Certain parts of this information must be reported to employees, state and local governmental authorities and local citizens upon request. We are subject to OSHA process safety

management regulations and EPA risk management plan rules that are designed to identify and establish procedures to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. Compliance with these laws is not expected to have a material adverse effect on our business, financial position, results of operations or cash flows.

The Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 increased penalties for safety violations, established additional safety requirements for newly-constructed pipelines and required studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines. PHMSA has also published notices and advanced notices of proposed rulemaking to solicit comments on the need for changes to its safety regulations, including whether to revise the integrity management requirements, and finalized revisions to its hazardous liquid pipeline regulations in early 2019. Compliance with such legislative and regulatory changes could increase our regulatory compliance costs and have a material adverse effect on our results of operations.

Security. Our assets can be subject to both physical and cyber security regulations depending on the nature of the facility. Some of our assets are regulated by the Department of Transportation, the EPA, the United States Coast Guard and the Department of Homeland Security (“DHS”). Compliance with these regulations is achieved by creating physical security plans, minimal physical security standards, marine terminal security drills and annual security audits of both marine and DHS regulated facilities. Compliance with these laws is not expected to have a material adverse effect on our business, financial position, results of operations or cash flows.

Title to Properties

Substantially all of our pipelines are constructed on rights-of-way granted by the apparent record owners of the property, and in some instances, these rights-of-way have limited terms that may require periodic renegotiation or, if such negotiations are unsuccessful, may require us to seek to exercise the power of eminent domain where such remedy is available. Several rights-of-way for our pipelines and other real property assets are shared with other pipelines and by third parties. In many instances, lands over which rights-of-way have been obtained are subject to prior liens, which have not been subordinated to the rights-of-way grants. We have obtained permits from public authorities to cross over or under, or to lay facilities in or along, water courses, county roads, municipal streets and state highways, and in some instances, these permits are revocable at the election of the grantor. We have also obtained permits from railroad companies to cross over or under lands or rights-of-way, many of which are also revocable at the grantor’s election. In some cases, property for pipeline purposes was purchased in fee. In some states and under some circumstances, we have the right of eminent domain to acquire rights-of-way and land necessary for our pipelines.

Some of the leases, easements, rights-of-way, permits and licenses that have been transferred to us are only transferable with the consent of the grantor of these rights, which in some instances is a governmental entity. We believe that we have obtained or will obtain sufficient third-party consents, permits and authorizations to operate our business in all material respects.

We believe that we have satisfactory title to all of our assets. Although title to our properties is subject to encumbrances in some cases, such as customary interests generally retained in connection with the acquisition of real property, liens that can be imposed in some jurisdictions for government-initiated action to clean up environmental contamination, liens for current taxes and other burdens, and easements, restrictions and other encumbrances to which the underlying properties were subject at the time of acquisition, we believe that none of these burdens should materially detract from the value of our properties or from our interest in them or should materially interfere with their use in the operation of our business.

Employees

As of December 31, 2018, we had 1,868 employees, 948 of which were assigned to our refined products segment and concentrated in the central U.S. Approximately 24% of the 948 employees are represented by the United Steel Workers (“USW”) and were covered by a collective bargaining agreement that expired in January 2019. We are operating under a 24-hour rolling extension of this agreement while negotiations for a new agreement continue. Management expects that we will be able to successfully negotiate a new long-term agreement with the USW; however, a prolonged work stoppage by these employees could have a material adverse effect on our business activities, results of operations and cash flows. At December 31, 2018, 160 of our employees were assigned to our crude oil segment and were concentrated in the central U.S., and none of these employees were covered by a collective bargaining agreement. There were 201 employees assigned to our marine storage segment at December 31, 2018, primarily in the Gulf and East Coast regions of the U.S., with approximately 14% of these employees represented by the International Union of Operating Engineers and covered by a collective bargaining agreement that expires in October 2020.

(d) Financial Information About Geographical Areas

We have no international activities. For all periods included in this report, all of our revenue was derived from operations conducted in, and all of our assets were located in, the U.S. See Note 15—Segment Disclosures in the notes to consolidated financial statements included in Item 8 of this report for information regarding our revenue and total assets.

(e) Available Information

Our internet address is www.magellanlp.com. We make available free of charge on or through our website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the “Exchange Act”), as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

Item 1A. Risk Factors

The nature of our business activities subjects us to a wide variety of hazards and risks. The following is a summary of the material risks relating to our business activities that we have identified. In addition to the factors discussed elsewhere in this Annual Report on Form 10-K, you should carefully consider the risks and uncertainties described below, which could have a material adverse effect on our business, financial condition or results of operations. These risks are not the only risks that we face. Our business could be impacted by additional risks and uncertainties not currently known or that we currently believe to be immaterial. If any of these risks actually occur, they could materially harm our business, financial condition or results of operations and impair our ability to implement our business plans or complete development projects as scheduled.

Risks Related to Our Business

Our cash distributions are not guaranteed. The cash from operations that we generate could decrease or fail to meet expectations, either of which could reduce our ability to pay quarterly cash distributions.

The amount of cash we can distribute to our limited partners principally depends upon the cash we generate from our operations, as well as cash reserves established by our general partner. Our distributable cash flow does not depend solely on profitability, which is affected by non-cash items. As a result, we could pay cash distributions during periods when we record net losses and could be unable to pay cash distributions during periods when we record net income. In

addition, the amount of cash we generate from operations is affected by numerous factors beyond our control, fluctuates from quarter to quarter and may change over time. Significant or sustained reductions in the cash generated by our operations would reduce our ability to pay quarterly distributions. Any failure to pay

distributions at expected levels could result in a loss of investor confidence and a decrease in the value of our unit price.

Our financial results depend on the demand for the petroleum products that we transport, store and distribute, among other factors. Unfavorable economic conditions, technological changes, regulatory developments or other factors in the U.S. or global marketplace could result in lower demand for these products for a sustained period of time.

Any sustained decrease in demand for petroleum products in the markets served by our pipelines or terminals could result in a significant reduction in the volume of products that we transport, store or distribute, and thereby reduce our cash flow and our ability to pay cash distributions. Global economic conditions have from time to time resulted in reduced demand for the products transported and stored by our pipelines and terminals and consequently for the services that we provide. Our financial results may also be affected by uncertain or changing economic conditions within certain regions, or by supply or demand shifts between regions. If economic and market conditions remain uncertain or adverse conditions persist for an extended period, we could experience material impacts to our business, financial condition or results of operations.

Other factors that could lead to a decrease in demand for the petroleum products we transport, store and distribute include:

an increase in the use of alternative fuel sources, such as ethanol, biodiesel, natural gas, fuel cells, solar, electric and battery-powered engines. Several countries and some automobile manufacturers have announced plans to significantly reduce or eliminate the use of fossil-fuel powered vehicles, and significant increases in the production of electric vehicles is widely expected. In addition, current U.S. laws require a significant increase in the quantity of ethanol and biodiesel used in transportation fuels each year until 2022. Increases in the use of such alternative fuels could have a material impact on the volume of petroleum-based fuels transported on our pipelines or distributed through our terminals;

an increase in transportation fuel economy, whether as a result of a shift by consumers to more fuel-efficient vehicles, technological advances by manufacturers or federal, state or international regulations. For example, the National Highway Traffic Safety Administration and the EPA have recently proposed new standards to amend the Corporate Average Fuel Economy (“CAFE”) and greenhouse gas emissions standards for passenger cars and light trucks manufactured in model years 2021 through 2026 that will require increases in fuel efficiency. These standards are intended to reduce demand for petroleum products and could reduce demand for our services;

changes in population or changes in consumer preferences, rates of automobile ownership or driving patterns in the markets we serve;

an increase or decrease in the market prices of petroleum products, which may reduce supply or demand. Petroleum product prices have been volatile in recent years and that volatility may continue in ways that we are unable to predict;

higher fuel taxes or other governmental or regulatory actions that increase the cost of the products we handle; and

lower exports of petroleum products to global markets resulting from weak economic conditions, changing preferences for the type of petroleum products we export or preferences for alternative energy sources.

A decrease in crude oil production in the basins served by our crude oil pipelines could reduce our transportation revenues, which could adversely impact our results of operations and the amount of cash we generate.

Numerous factors can cause reductions in crude oil production in the regions served by our pipelines, including, among other factors, lower overall crude oil prices, regional price or quality differences, higher costs of crude oil production, exhaustion of reserves, weather or other natural causes, adverse regulatory or legal developments, disruptions in financial or credit markets that inhibit the ability of our customers to finance the costs of production, or lower overall demand for crude oil and the products derived from crude oil. Crude oil prices have historically exhibited significant volatility, and are influenced by, among other factors, worldwide and domestic supplies of and demand for crude oil, political and economic developments in often-volatile producing regions, actions taken by the Organization of Petroleum Exporting Countries, technological developments, government regulations, taxes, policies regarding the importing and exporting of crude oil and conditions in global financial markets.

We are unable to predict future prices of crude oil or what impact the crude price environment will have on future production overall, and specifically on production in the basins we serve. Lower production in the regions served by our pipelines could result in lower shipments of uncommitted volume or could cause us to be unable to renew our contracts at existing volumes or rates. Any sustained decrease in the production of crude oil in the regions served by our crude oil pipelines could result in a significant reduction in the volume of products that we transport or the rates we are able to charge for such transportation services or both, thereby reducing our cash flow and our ability to pay cash distributions.

We depend on producers, gatherers, refineries and petroleum pipelines owned and operated by others to supply our assets.

We depend on crude oil production and on connections with gathering systems, refineries and petroleum pipelines owned and operated by third parties to supply our assets. We cannot control or predict the amount of crude oil that will be delivered to us by the gathering systems and pipelines that supply our crude oil assets, nor can we control or predict the output of refineries that supply our refined products pipelines and terminals. Changes in the quality or quantity of this crude oil production, outages at these refineries or reduced or interrupted throughput on these gathering systems or pipelines due to weather-related or other natural causes, competitive forces, testing, line repair, damage, reduced operating pressures or other causes could reduce shipments on our pipelines or result in our being unable to receive products at or deliver products from our terminals or receive products for processing at our condensate splitter, any of which could materially adversely affect our cash flows and ability to pay cash distributions.

The closure of refineries that supply or are supplied by our refined products and crude oil pipelines could result in disruptions or reductions in the volumes we transport and store and in the amount of cash we generate.

Refineries that supply or are supplied by our facilities are subject to regulatory developments, including but not limited to regulations regarding fuel specifications, plant emissions and safety and security requirements that could significantly increase the cost of their operations and reduce their operating margins. For example, costs to comply with renewable fuel standards have negatively impacted the profitability of numerous independent refineries and were cited as the primary cause of a bankruptcy filing of a refining company in January 2018. In addition, the profitability of the refineries that supply our facilities is subject to regional and global supply and demand dynamics that are difficult to predict. A period of sustained weak demand or increased cost of supply could make refining uneconomic for some refineries, including those located along our refined products and crude oil pipelines. The closure of a refinery that delivers product to or receives crude from our pipelines could reduce the volumes we transport and the amount of cash we generate. Further, the closure of these or other refineries could result in our customers electing to store and distribute petroleum products through their proprietary terminals, which could result in a reduction of our storage volumes.

A decrease in contract renewals or renewals at lower rates or shorter terms could cause our revenue to decline or be more volatile, which could adversely impact our results of operations and the amount of cash we generate and our ability to make cash distributions.

A significant portion of the revenue we earn from providing petroleum products transportation and storage services is provided for in multi-year contracts negotiated with our customers. Many of those contracts require our customers to pay for our services regardless of market conditions during the contract period. Changing market conditions, including changes in petroleum product supply or demand patterns, competitive factors, forward-price structure, financial market conditions, regulations, accounting rules or other factors could cause our customers to be unwilling to renew their contracts with us when those contracts terminate, or make them willing to renew only at lower rates or for shorter contract periods. For example, the initial term of our contracts for the Longhorn pipeline expired in September 2018, and some shippers elected to extend their contracts under current terms for an additional two years, while others executed new contracts with lower incentive tariff rates and terms up to 10 years, resulting in an average contract term of five years and a lower average tariff rate.

Competition could lead to lower levels of profits and reduce the amount of cash we generate.

We compete with other pipelines and terminals that provide similar services in the same markets as our assets. In addition, our competitors could construct new assets or redeploy existing assets in a manner that would result in more intense competition in the markets we serve. For example, storage facilities previously used to support refineries or other facilities have in some cases been redeployed to provide services that compete with our own services. Similarly, in some cases pipelines previously used to provide services that did not compete with us have been repurposed to provide services that directly compete with certain of our services.

We compete with other transportation, storage and distribution alternatives on the basis of many factors, including but not limited to rates, service levels and offerings, geographic location, connectivity and reliability. Our customers could utilize the assets and services of our competitors instead of our assets and services, or we could be required to lower our prices or increase our costs to retain our customers.

Many of the competitors of our crude oil segment conduct extensive crude oil gathering and marketing activities that we do not currently participate in and that could enhance their competitive position. We filed a petition for declaratory order in November 2016 requesting a FERC determination that our proposal to establish a crude oil marketing affiliate and engage in certain marketing activities would be in compliance with the Interstate Commerce Act. In late 2017, the FERC denied our request, and we and other industry participants subsequently submitted requests for further clarification or rehearing from the FERC. The FERC has not yet taken action on those requests. We are unable to predict the outcome of these proceedings. If we are ultimately unable to offer services and conduct activities similar to those offered and conducted by our competitors, our competitive position could be negatively impacted.

Any of these or other competitive forces could materially adversely affect our results of operations, financial position or cash flows, as well as our ability to pay cash distributions.

Our business is subject to the risk of a capacity overbuild in some of the markets in which we operate.

We and our joint ventures have made and continue to make significant investments in new energy infrastructure to meet market demand, as have several of our competitors. For example, we have invested significantly in pipelines to deliver crude oil from the Permian Basin in West Texas to markets along the U.S. Gulf Coast and from the DJ Basin in Colorado to Cushing, Oklahoma. Similar investments have been made and additional investments may be made in the future by us, our competitors or by new entrants to the markets we serve. In addition, we are in the process of expanding a marine terminal along the Houston Ship Channel in Pasadena, Texas. The success of these and similar

projects largely relies on the realization of anticipated market demand, and these projects typically require significant development periods, during which time demand for such infrastructure may change, or additional investments by competitors may be made. If infrastructure investments by us or others in the markets we serve result in capacity that exceeds the demand in those markets, our facilities could be

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underutilized, and we could be forced to reduce the rates we charge for our services, which could materially affect our results of operations, financial position or cash flows, as well as our ability to pay cash distributions.

Mergers among our customers and competitors could result in lower volumes being shipped on our pipelines or products stored in or distributed through our terminals, thereby reducing the amount of cash we generate.

Mergers among our existing customers and our competitors could provide strong economic incentives for the combined entities to utilize their existing systems instead of ours in those markets where our systems compete. As a result, we could lose some or all of the volumes and associated revenue from these customers. As a significant portion of our operating costs are fixed, a reduction in volumes would result not only in less revenue, but also a decline in cash flow of a similar magnitude, which could materially adversely affect our results of operations, financial position or cash flows, as well as our ability to pay cash distributions.

Reduced volatility in energy prices or new government regulations could discourage our storage customers from holding positions in petroleum products, which could adversely affect the demand for our storage services.

We have constructed and continue to build new storage tanks in response to increased customer demand for storage. Many of our competitors have also built new storage facilities. The demand for new storage has resulted in part from our customers' desire to have the ability to take advantage of profit opportunities created by volatility in the prices of petroleum products. Periods of prolonged stability in petroleum product prices or extended declining trends of crude oil prices could reduce demand for our storage services. If federal, state or international regulations are passed that discourage our customers from storing these commodities, demand for our storage services could decrease, in which case we may be unable to identify customers willing to contract for such services or be forced to reduce the rates we charge for our services. The realization of any of these risks could materially reduce the amount of cash we generate.

The volume of crude oil we transport and the tariff rates we collect for transportation services partially depend upon unpredictable market differentials between our origin points and our destination points.

Our tariff rates are established in accordance with federal and state regulations which, in general, permit us to negotiate rates with shippers so long as such negotiated rates are not unduly discriminatory among similarly situated shippers. Applicable regulations and our obligations to certain classes of committed shippers may limit our ability to change our tariff rates. When the difference in market prices for crude oil between our origin points and our destination points is lower than our tariff rates, the volume of product we transport could decline or the average tariff rate we collect could decrease. For example, if the posted tariff rate for transportation on the Longhorn pipeline is higher than the market differential for a given month, it would likely be uneconomical for shippers, other than those that have contractual obligations to ship or pay during that month, to use Longhorn to move volumes from the Permian Basin to Houston. As a result, we would experience lower revenues, which would adversely impact our results of operations and the amount of cash we generate.

Fluctuations in prices of petroleum products that we purchase and sell could materially affect our results of operations.

We generate product sales revenue from our butane blending and fractionation activities, as well as from the sale of product generated by the operations of our pipelines and terminals. We also maintain product inventory related to these activities. Significant fluctuations in market prices of petroleum products could result in unrealized gains or losses on transactions we enter to hedge our exposure to commodity price changes. To the extent these transactions have not been designated as hedges for accounting purposes, the associated unrealized gains and losses directly impact our reported results of operations. In addition, significant fluctuations in market prices of petroleum products could result in losses or lower profits from these activities, thereby reducing the amount of cash we generate and our ability to pay cash distributions.

We hedge prices of petroleum products by utilizing physical purchase and sale agreements and exchange-traded futures contracts. These hedging arrangements do not eliminate all price risks, could result in fluctuations in quarterly or annual financial results and could result in material cash obligations that could negatively impact our financial position or our ability to pay distributions to our unitholders. Further, non-compliance with our risk management policies and procedures could result in significant losses.

We hedge our exposure to price fluctuations for our petroleum products purchase and sale activities by utilizing physical purchase and sale agreements and exchange-traded futures contracts. To the extent these hedges do not qualify for hedge accounting treatment or are not designated as hedges, or if they result in material amounts of ineffectiveness, we could experience material fluctuations in our quarterly or annual reported results of operations. We may be required to post margin in connection with these hedges, which could result in material and unpredictable demands on our liquidity. These contracts may be for the purchase or sale of product in markets for a time frame different from those in which we are attempting to hedge our exposure, resulting in hedges that do not eliminate all price risks. In addition, our product sales and hedging operations involve the risk of non-compliance with our risk management policies. We cannot assure you that our processes and procedures will detect and prevent all violations of our risk management policies, particularly if deception or other intentional misconduct is involved. If we incur a material loss related to commodity price risks, including non-compliance with our risk management policies and procedures, our quarterly or annual results of operations or cash flows could be negatively impacted, which could have a negative impact on our unit price. Further, our requirement to post material amounts of margin in connection with our hedges could negatively impact our liquidity and our ability to pay distributions to our unitholders.

Changes in price levels could negatively impact our revenue, our expenses, or both, which could adversely affect our results from operations, our liquidity and our ability to pay cash distributions.

The operation of our assets and the implementation of our growth strategy require significant expenditures for labor, materials, property, equipment and services. Increases in the cost of these items could materially increase our expenses or capital costs. We may not be able to pass these increased costs on to our customers in the form of higher fees for our services.

Because we use the FERC's PPI-based price indexing methodology to establish tariff rates in certain markets served by our pipelines, our revenues may be impacted by changes in price levels. The FERC's indexing methodology is subject to review every five years and limits a pipeline's rates in such markets each year to a new ceiling level, which is calculated as the previous year's ceiling level multiplied by a percentage. For the five-year period beginning July 1, 2016, the indexing method provides for annual changes equal to the change in the PPI-FG plus 1.23%. This methodology could result in changes in our revenue that do not fully reflect changes in the costs we incur to operate and maintain our pipelines. For example, our costs could increase more quickly or by a greater amount than the PPI-FG index plus 1.23% used by the current FERC methodology. Further, in periods of general price deflation, the ceiling level provided for by the FERC's index methodology could decrease requiring us to reduce our index-based rates, even if the actual costs we incur to operate our assets increase. Changes in price levels that lead to decreases in our revenue or increases in the prices we pay to operate and maintain our assets could adversely affect our results of operations, financial position or cash flows, as well as our ability to pay cash distributions.

Our business involves many hazards and operational risks, the occurrence of which could materially adversely affect our results of operations, financial position or cash flows and our ability to pay cash distributions. Non-compliance with our policies and procedures could result in significant losses.

Our operations are subject to many hazards inherent in the transportation and distribution of petroleum products and ammonia, including ruptures, leaks and fires. In addition, our operations are exposed to potential natural disasters, including hurricanes, tornadoes, storms, floods and earthquakes. For example, in 2017, Hurricane Harvey hit the

Texas Gulf Coast, disrupting our operations and negatively impacting our financial results. The risk of natural disasters and other operational risks could result in substantial losses due to personal injury or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage, and may

result in curtailment or suspension of our related operations. Some of our assets are located in or near high consequence areas such as residential and commercial centers or sensitive environments, and the potential damages are even greater in these areas. If a significant accident or event occurs or if any of our employees or agents violate or fail to observe the various policies and procedures we have adopted, including operational policies, safety policies and our code of business conduct, it could materially adversely affect our results of operations, financial position or cash flows and our ability to pay cash distributions.

Many of our storage tanks and significant portions of our pipeline system have been in service for several decades.

Our pipeline and storage assets are generally long-lived assets. As a result, some of our assets have been in service for several decades. The age and condition of these assets could result in increased maintenance or remediation expenditures and an increased risk of product releases and associated costs and liabilities. Any significant increase in these expenditures, costs or liabilities could materially adversely affect our results of operations, financial position or cash flows, as well as our ability to pay cash distributions.

We do not own all of the property on which our pipelines and facilities are located, and we rely on securing and retaining adequate rights-of-way and permits in order to operate our existing assets and complete growth projects. We do not own all of the land on which our pipelines and facilities are located. As such, we are subject to the possibility of increased costs to retain necessary land use. In those instances in which we do not own the land on which our facilities are located, we obtain the rights to construct and operate our pipelines on land owned by third parties or governmental agencies for a specific period of time. In addition, some of our facilities cross Native American lands pursuant to rights-of-way of limited terms. We may not be able to utilize the right of eminent domain in some jurisdictions and in some circumstances, such as land owned by Native American tribes or other government entities. Our ability to secure required permits and rights-of-way or otherwise proceed with construction of our expansion projects could encounter opposition from activists who may attempt to delay pipeline construction through protests and other means. The loss of these rights, through our inability to acquire or renew right-of-way contracts or otherwise, could have a material adverse effect on our business, financial condition, results of operations, cash flows and our ability to make cash distributions to unitholders.

Our assets may not be adequately insured, and we could experience losses that exceed our insurance coverage.

We are not fully insured against all hazards or operational risks related to our businesses, and the insurance we carry requires that we meet certain deductibles before we can collect for any losses we sustain. If a significant accident or event occurs that is not fully insured, it could materially adversely affect our results of operations, financial position or cash flows and our ability to pay cash distributions.

We may encounter increased costs related to and decreases in the availability of insurance.

Premiums and deductibles for our insurance policies could escalate as a result of market conditions or losses experienced by us or by other companies. In some instances, insurance could become unavailable or available only for reduced amounts of coverage. Increases in the cost of insurance or the inability to obtain insurance at rates that we consider commercially reasonable could materially affect our results of operations, financial position or cash flows and our ability to pay cash distributions.

Terrorist attacks aimed at our facilities or that impact our customers or the markets we serve could adversely affect our business.

The U.S. government has issued warnings that energy assets in general, and the nation's pipeline and terminal infrastructure in particular, may be targets of terrorist organizations. The threat of terrorist attacks subjects our

operations to increased risks. Any terrorist attack on our facilities, those of our customers or, in some cases, on

energy infrastructure owned by others, could have a material adverse effect on our business. Similarly, any terrorist attack that severely disrupts the markets we serve could materially adversely affect our results of operations, financial position or cash flows, as well as our ability to pay cash distributions.

Cyber-attacks, or other information security breaches, that circumvent security measures taken by us or others with whom we conduct business or share information could result in increased costs or other damage to our business. We rely on our information technology infrastructure to process, transmit and store electronic information, including information we use to safely operate our assets. In addition, we rely on third-party systems, including for example the electric grid and cloud-based software services, which could also be subject to security breaches or cyber attacks, and the failure of which could have a significant adverse effect on the operation of our assets. We and our third-party providers face cybersecurity and other security threats to our information technology infrastructure, which could include threats to our control systems and safety systems that operate our pipelines and other assets. We could face unlawful attempts to gain access to our information technology infrastructure, including coordinated attacks from hackers, including state-sponsored groups, “hacktivists” or private individuals. The age, operating systems or condition of our current information technology infrastructure and software assets and our ability to maintain and upgrade such assets could affect our ability to resist cybersecurity threats. We could also face attempts to obtain unauthorized access by targeting acts of deception against individuals with legitimate access to physical locations or information. Breaches in our information technology infrastructure or physical facilities, or other disruptions including those arising from theft, vandalism, fraud or unethical conduct, could result in damage to our assets, unnecessary waste, safety incidents, damage to people, property and the environment, reputational damage, potential liability or the loss of contracts, and could adversely affect our results of operations, financial position or cash flows, as well as our ability to pay cash distributions.

Failure of critical information technology systems may impact our ability to operate our assets or manage our businesses, thereby reducing the amount of cash available for distribution.

We utilize information technology systems to operate our assets and manage our businesses. Some of these systems are proprietary systems that require specialized programming capabilities, while others are based upon or rely on technology that has been in service for many years. Failures of these systems could result in a breach of critical operational or financial controls and lead to a disruption of our operations, commercial activities or financial processes. Such failures could adversely affect our results of operations, financial position or cash flow, as well as our ability to pay cash distributions.

Our expansion projects may not immediately produce operating cash flows and may exceed our cost estimates or experience delays.

We have undertaken numerous large expansion projects that have required and will continue to require us to make significant capital investments. We often finance those projects primarily with new borrowings, and we will incur financing costs during the planning and construction phases of these projects; however, the operating cash flows we expect these projects to generate will not materialize until sometime after the projects are completed, if at all. As a result, our leverage ratio relative to our earnings may increase during the period prior to the generation of those operating cash flows. In addition, the amount of time and investment necessary to complete these projects could materially exceed the estimates we used when determining whether to undertake them. For example, we must compete with other companies for the materials and construction services required to complete these projects, and competition for these materials or services could result in significant delays or cost overruns.

Similarly, we must secure and retain required permits and rights-of-way in order to complete and operate these projects, and our inability to do so in a timely manner could result in significant delays or cost overruns. Our ability to secure required permits and rights-of-way or otherwise proceed with construction of our expansion projects could

encounter opposition from political activists, who may attempt to delay pipeline construction through protests and

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other means. Further, in many instances, the operations of our expansion projects are subject to the completion by third parties of pipeline connections or other related projects that are beyond our control. Delays or unanticipated costs associated with these third parties in the completion of these related projects could result in delays or cost overruns in the start-up of our own projects. In addition, we run the risk of failing to meet commitments to our customers as a result of project delays, which in some cases could allow our customers to terminate their commitments to us or otherwise negatively impact customer relationships and future financial results. Any cost overruns or unanticipated delays in the completion or commercial development of our expansion projects could reduce the anticipated returns on these projects, which in turn could materially increase our leverage and reduce our liquidity and our ability to pay cash distributions.

Potential future acquisitions and expansions may affect our business by substantially increasing the level of our indebtedness and liabilities, subjecting us to the risk of being unable to effectively integrate the new operations and diluting our limited partner unitholders.

From time to time we evaluate and acquire assets and businesses. We may issue significant amounts of additional equity securities and incur substantial additional indebtedness to finance future acquisitions, and our capitalization and results of operations may change significantly as a result. Our limited partner unitholders may not have an opportunity to review or evaluate the information and assumptions we use to determine whether to pursue an acquisition. An acquisition that we expect to be accretive could nevertheless reduce our cash from operations if we rely on faulty information, make inaccurate assumptions, assume unidentified liabilities or otherwise improperly value the acquired assets. In addition, any equity securities we issue to finance acquisitions would dilute our existing limited partner unitholders and could reduce our cash flow available for distribution on a per unit basis.

Acquisitions and business expansions involve numerous risks, including but not limited to difficulties in the assimilation of the assets and operations of the acquired businesses, inefficiencies and difficulties that arise due to our unfamiliarity with new assets and the businesses associated with them and their markets, challenges in managing or retaining new employees and establishing relationships with and retaining new customers and business partners, and the diversion of management's attention from other business concerns. Further, unexpected costs and challenges may arise whenever businesses with different operations or management are combined, and we may experience unanticipated delays in realizing the benefits of an acquisition. Following an acquisition, we may discover previously unknown liabilities associated with the acquired business for which we have no recourse from the seller.

We compete for acquisitions and new projects with numerous other established energy companies and many other potential investors. Increased competition for acquisitions or growth projects could limit our ability to execute our growth strategy or could result in our executing that strategy on substantially less attractive terms than we have previously experienced, either of which could have a material adverse effect on our results of operations or cash flows, as well as our ability to pay cash distributions.

Failure to generate or complete additional growth projects or make future acquisitions could reduce our ability to maintain or increase cash distributions to our unitholders.

Our ability to maintain or increase distributions to our unitholders depends to a significant degree on our ability to successfully identify and execute additional growth projects and acquisitions. We face significant uncertainties and competition in the pursuit of such opportunities. For example, decisions regarding new growth projects rely on numerous estimates, including among other factors, predictions of future demand for our services, future supply shifts, crude oil production estimates, commodity price environments, regulatory developments, economic conditions and potential changes in the financial condition of our customers. Our predictions of such factors could cause us to forego certain investments or to lose opportunities to competitors who make investments based on more aggressive predictions or who are generally more tolerant of risk. Valuations of energy infrastructure assets have generally been

elevated in recent years, which has made it difficult for us to be successful in our attempts to acquire new assets, as other bidders for those assets have been willing to pay prices and accept terms that did not meet our risk and return criteria. We cannot be certain that our own predictions are more accurate than those of other bidders, and our approach to risk could cause us to miss opportunities that could otherwise have created

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value for our unitholders. If we are unable to acquire new assets or develop additional expansion projects, we may not be able to maintain or increase distributions to our unitholders.

We do not have the same flexibility as other types of organizations to accumulate cash and retained earnings to protect against illiquidity in the future, and we rely on access to capital to fund acquisitions and growth projects and to refinance existing debt obligations. Unfavorable developments in capital markets could limit our ability to obtain funding or require us to secure funding on terms that could limit our financial flexibility, reduce our liquidity, dilute the interests of our existing unitholders and reduce our cash flows and ability to pay distributions.

Our partnership agreement requires us to make quarterly distributions to our unitholders of all available cash, after taking into account reserves for commitments and contingencies, including capital investments, operating costs and debt service requirements. As a result, we do not accumulate equity in the form of retained earnings in a manner typical of many other forms of organization, including most traditional public corporations. As a result, we are more likely than those organizations to require issuances of additional capital to finance our growth plans, meet unforeseen cash requirements and service our debt.

We regularly consider and pursue growth projects and acquisitions as part of our efforts to increase cash available for distribution to our unitholders. These transactions can be effected quickly, may occur at any time and may be significant in size relative to our existing assets and operations. For example, we estimate that we will spend approximately \$1.7 billion to complete our current slate of organic growth projects. We generally do not retain sufficient cash flow to finance such projects and acquisitions, and consequently the execution of our growth strategy requires regular access to external sources of capital. Similarly, we generally do not retain sufficient cash flow to repay our indebtedness when it matures, and we rely on new capital to refinance these obligations. Any limitations on our access to capital on satisfactory terms will impair our ability to execute this strategy and could reduce our liquidity and our ability to make cash distributions.

Limitations on our access to capital, including on our ability to issue additional debt and equity, could result from events or causes beyond our control, and could include, among other factors, decreases in our creditworthiness or profitability, significant increases in interest rates, increases in the risk premium generally required by investors or in the premium required specifically for investments in energy-related companies or master limited partnerships, and decreases in the availability of credit or the tightening of terms required by lenders. Any limitations on our ability to refinance these obligations by securing new capital on satisfactory terms could severely limit our liquidity, our financial flexibility or our cash flows, and could result in the dilution of the interests of our existing unitholders.

Increases in interest rates could increase our financing costs, reduce the amount of cash we generate and adversely affect the trading price of our units.

As of December 31, 2018, the face value of our outstanding fixed-rate debt was \$4.3 billion. We have a commercial paper program under which we may issue commercial paper notes in an amount up to the available capacity under our \$1.0 billion revolving credit facility, and we expect to make additional floating rate borrowings under our commercial paper program or revolving credit facility as needed. As a result, we would have exposure to changes in short-term interest rates. We may also use interest rate derivatives to effectively convert some of our fixed-rate notes to floating-rate debt, thereby increasing our exposure to changes in short-term interest rates. In addition, the execution of our growth strategy and the refinancing of our existing debt could require that we issue additional fixed-rate debt, and consequently we also have potential exposure to changes in long-term interest rates. Rising interest rates could reduce the amount of cash we generate and materially adversely affect our liquidity and our ability to pay cash distributions. Moreover, the trading price of our units is sensitive to changes in interest rates and could be materially adversely affected by any increase in interest rates.

Restrictions contained in our debt instruments may limit our financial flexibility.

We are subject to restrictions with respect to our debt that may limit our flexibility in structuring or refinancing existing or future debt and may prevent us from engaging in certain beneficial transactions. These restrictions include, among other provisions, the maintenance of certain financial ratios, as well as limitations on our ability to

incur additional indebtedness, to grant liens or to repay existing debt without prepayment premiums. These restrictions could result in higher costs of borrowing and impair our ability to generate additional cash.

The amount and timing of distributions to us from our joint ventures is not within our control, and we may be unable to cause our joint ventures to take or refrain from taking certain actions that may be in our best interest. In addition, as construction manager and operator of the majority of our joint ventures, we are exposed to additional risk and liability in connection with our responsibilities in those capacities.

As of December 31, 2018, we were engaged in eight joint ventures, all of which are in the form of limited liability companies (“LLC”), in which we share control with other entities according to the relevant joint venture agreements. Those agreements provide that the respective LLC management committees, including our representatives along with the representatives of the other owners of those LLCs, determine the amount and timing of distributions. Our joint ventures may establish separate financing arrangements that contain restrictive covenants that may limit or restrict the LLC’s ability to make cash distributions to us under certain circumstances. Any inability to generate cash or restrictions on cash distributions we receive from our joint ventures could impair our results of operations, cash flows and our ability to pay cash distributions.

In the case of Double Eagle and Seabrook, an affiliate of our joint venture co-owner serves as operator, and consequently we rely on affiliates of our joint venture co-owner for many of the management functions of those joint ventures. Without the cooperation of the other owners of those joint ventures, we may not be able to cause our joint ventures to take or not take certain actions, even though those actions or inactions may be in the best interest of us or the particular joint venture. With respect to our other joint ventures, we are the construction manager and operator, which exposes us to additional risk and liability in connection with our responsibilities in those capacities.

If we are unable to agree with our joint venture co-owners on a significant matter, it could result in delays, litigation or operational impasses that could result in a material adverse effect on that joint venture’s financial condition, results of operations or cash flows. If the matter is significant to us, it could result in a material adverse effect on our results of operations, financial position or cash flows. If we fail to make a required capital contribution, we could be deemed to be in default under the applicable joint venture agreement. Our joint venture co-owners may be permitted to pursue a variety of remedies, including funding any deficiency resulting from our failure to make such capital contribution, which would result in a dilution of our ownership interest, or, in some cases, our joint venture co-owners may have the option to purchase all of our existing interest in the subject joint venture.

Moreover, subject to certain limitations in the respective joint venture agreements, any joint venture owner may sell or transfer its ownership interest in a joint venture, whether in a transaction involving third parties or the other joint venture owners. Any such transaction could result in our being co-owners with different or additional parties with whom we have not had a previous relationship.

We are exposed to counterparty risk. Nonpayment, commitment termination or nonperformance by our customers, vendors, joint venture co-owners, lenders or derivative counterparties could materially reduce our revenue, increase our expenses, impair our liquidity or otherwise negatively impact our results of operations, financial position or cash flows and our ability to pay cash distributions.

We are subject to risks of loss resulting from nonpayment or nonperformance by our customers to whom we extend credit. In addition, we frequently undertake capital expenditures based on commitments from customers from which we expect to realize the expected return on those expenditures, including take-or-pay commitments from our customers. Nonperformance by our customers of those commitments or termination of those commitments resulting from our inability to timely meet our obligations could result in substantial losses to us. For example, we plan to spend nearly \$1 billion to construct refined products pipelines in Texas based on customer commitments. Nonperformance

by customers who back our capital projects could significantly impact our expected return from those projects.

We have undertaken numerous projects that require cooperation with and performance by joint venture co-owners. For example, Seabrook is operated by our joint venture co-owner, LBC Tank Terminals, LLC, which also

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must make capital contributions to the joint venture. Nonperformance by our joint venture co-owners could result in increased costs or delays that could decrease our returns on our joint venture projects.

We utilize third-party vendors to provide various functions, including, for example, certain construction activities, engineering services, facility inspections and operation of certain software systems. Using third parties to provide these functions has the effect of reducing our direct control over the services rendered. The failure of one or more of our third-party providers to deliver the expected services on a timely basis at the prices we expect and as required by contract could result in significant disruptions, costs to our operation or instances of a contractor's non-compliance with applicable laws and regulations, which could materially adversely affect our business, financial condition, operating results or cash flows.

We also rely to a significant degree on the banks that lend to us under our revolving credit facility for financial liquidity, and any failure of those banks to perform on their obligations to us could significantly impair our liquidity. Furthermore, nonpayment by the counterparties to our interest rate and commodity derivatives could expose us to additional interest rate or commodity price risk. Any take-or-pay commitment terminations or substantial increase in the nonpayment or nonperformance by our customers, vendors, lenders or derivative counterparties could have a material adverse effect on our results of operations, financial position or cash flows and our ability to pay cash distributions.

Losses sustained by any money market mutual fund or other investment vehicle in which we invest our cash or the failure of any bank or financial institution in which we deposit funds could adversely affect our financial position and our ability to pay cash distributions.

We may maintain material balances of cash and cash equivalents for extended periods of time. We typically invest any material amount of cash on hand in cash equivalents such as money market mutual funds. These funds are primarily comprised of highly rated short-term instruments. Significant market volatility and financial distress could cause such investments to lose value or reduce the liquidity of such investments. We may also maintain deposits at commercial banks in excess of amounts insured by government agencies such as the Federal Deposit Insurance Corporation. In addition, certain exchange-traded derivatives transactions we enter into in order to hedge commodity-related price exposures frequently require us to make margin deposits with brokers. A failure of our commercial banks or brokers could result in our losing any funds we have deposited. Any losses we sustain on the investments or deposits of our cash could materially adversely affect our financial position and our ability to pay cash distributions.

Rate regulation, challenges by shippers of the rates we charge on our refined products and crude oil pipelines or changes in the jurisdictional characterization of our assets or activities by federal, state or local regulatory agencies may reduce the amount of cash we generate.

The FERC regulates the rates we can charge, and the terms and conditions we can offer, for interstate transportation service on our refined products and crude oil pipelines. State regulatory authorities regulate the rates we can charge, and the terms and conditions we can offer, for intrastate movements on our refined products and crude oil pipelines. The determination of the interstate or intrastate character of shipments on our petroleum products pipelines may change over time, which may change the rates we are allowed to charge for transportation and other related services. Shippers may protest our pipeline tariff filings, and the FERC or state regulatory authorities may investigate tariff terms. Further, other than for rates set under market-based rate authority, the FERC may order refunds of amounts collected under interstate rates that are determined to be in excess of a just and reasonable level when taking into consideration our pipeline system's cost-of-service. State regulatory authorities could take similar measures for intrastate tariffs. In addition, shippers may challenge by complaint the lawfulness of tariff rates that have become final and effective. The FERC and state regulatory authorities may also investigate tariff terms absent shipper complaint. If existing rates challenged by complaint are determined to be in excess of a just and reasonable level when taking into

consideration our pipeline systems' cost-of-service, we could be required to pay refunds to shippers, reduce rates and make other concessions.

The FERC's ratemaking methodologies may limit our ability to set rates based on our actual costs or may delay the use of rates that reflect increased costs. The FERC's primary ratemaking methodology applicable to us is price indexing. We use this methodology to establish our rates in approximately 40% of the markets for our refined products pipelines. The FERC's indexing methodology is subject to review every five years and currently allows a pipeline to change its rates each year to a new ceiling level, which is calculated as the previous year's ceiling level multiplied by a percentage. For the five-year period beginning July 1, 2016, the indexing method provides for annual changes in rates by a percentage equal to the change in the PPI-FG plus 1.23%. When the ceiling level falls, as it did in 2015, we are required to reduce our rates that are subject to the FERC's price indexing methodology.

The FERC and relevant state regulatory authorities allow us to establish rates based on conditions in competitive markets without regard to the FERC's index level or our cost-of-service. We establish market-based rates in approximately 60% of the markets for our refined products pipelines. The tariffs on most of our crude oil pipelines are at negotiated rates, but are still ultimately subject to regulation by the FERC or state agencies and subject to protest by shippers. If we were to lose our market-based rate authority, or if our negotiated rates were determined to be not just and reasonable, we could be required to establish rates on some other basis, such as our cost-of-service, which could reduce our revenues.

In October 2016, the FERC issued an advanced notice of proposed rulemaking ("ANOPR") seeking comments on potential revisions to (1) the Commission's policies for evaluating oil pipeline indexed rate changes; and (2) the reporting requirements for page 700 of FERC Form No. 6, Annual Report of Oil Pipeline Companies. While we are unable to predict the ultimate form of rulemaking, if any, that could follow this advanced notice, the potential revisions discussed in the ANOPR could affect our ability to establish rates in a manner consistent with our past practice, while potentially preventing us from recovering increases in the costs we incur to operate our pipelines and increasing our cost of complying with FERC reporting requirements.

On March 15, 2018, the FERC issued a Revised Policy Statement on Treatment of Income Taxes in which the FERC found that an impermissible double recovery results from granting an MLP pipeline both an income tax allowance and a return on equity pursuant to the FERC's discounted cash flow methodology. The FERC revised its previous policy, stating that it would no longer permit an MLP pipeline to recover an income tax allowance in its cost of service. The FERC stated that it would incorporate the effects of the policy changes and the Tax Cuts and Jobs Act of 2017 on industry-wide pipeline costs in the 2020 five-year review of the liquids pipeline index level. The FERC will also apply the revised Policy Statement and the Tax Cuts and Jobs Act of 2017 to initial crude oil pipeline cost-of-service rates and cost-of-service rate changes on a going-forward basis under the FERC's existing ratemaking policies, including cost-of-service rate proceedings resulting from shipper-initiated complaints.

In November 2017, a shipper protested the rates and terms and conditions of service for expansion capacity on the BridgeTex pipeline system, in which we have a 30% interest, in filings with the FERC and Railroad Commission of Texas ("RRC"), alleging that the tariffs for the new capacity are discriminatory. We are unable to predict the outcome of these or any similar proceedings before the FERC, RRC or other authorities that regulate our tariffs. Successful protests of our tariffs or any other actions that require that we lower our rates, pay rebates to shippers or make other concessions could cause our revenues to decrease and reduce our cash flow from operations and our ability to make cash distributions.

Our operations are subject to extensive environmental, health, safety and other laws and regulations that impose significant requirements, costs and liabilities on us. These requirements, costs and liabilities could increase as a result of new laws or regulations or changes in the interpretation, implementation or enforcement of existing laws and regulations. Our customers are also subject to extensive environmental, health, safety and other laws and regulations, and any new laws or regulations or changes in the interpretation, implementation or enforcement of existing laws and regulations, including laws and regulations related to hydraulic fracturing, could result in decreased demand for our services.

Our operations are subject to extensive federal, state and local laws and regulations relating to the protection or preservation of the environment, natural resources and human health and safety, including but not limited to the CAA, the RCRA, the Oil Pollution Act, the CWA, the CERCLA, the HLPESA, the Pipeline Safety, Regulatory

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Certainty and Job Creation Act of 2011 and OSHA. Such laws and regulations affect almost all aspects of our operations and generally require us to obtain and comply with various environmental registrations, licenses, permits, credits, inspections and other approvals. We incur substantial costs to comply with these laws and regulations, and any failure to comply may expose us to civil, criminal and administrative fees, fines, penalties and interruptions in our operations that could have a material adverse impact on our results of operations, financial position and prospects. For example, if an accidental release or spill of petroleum products, chemicals or other hazardous substances occurs at or from our pipelines, storage or other facilities, we may experience significant operational disruptions, and we may have to pay a significant amount to remediate the release or spill, pay government penalties, address natural resource damages, compensate for human exposure and property damage, install costly pollution control equipment or undertake a combination of these and other measures. The resulting costs and liabilities could materially adversely affect our results of operations, financial position or cash flows. In addition, emission controls required under the CAA and other similar laws could require significant capital expenditures at our facilities.

Liability under such laws and regulations may be incurred without regard to fault. Private parties, including the owners of properties through which our pipelines pass, also may have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with such laws and regulations or for personal injury or property damage. Our insurance does not cover all environmental risks and costs and may not provide sufficient coverage in the event an environmental claim is made against us. In addition, our insurance may not cover us for fines and penalties levied against us by governmental agencies for releases that result in environmental damages.

Our assets have been used for many years to transport, store or distribute petroleum products and ammonia. Over time our operations, or operations by our predecessors or third parties not under our control, may have resulted in the disposal or release of hydrocarbons or solid wastes at or from our terminal properties and along pipeline rights-of-way. In addition, some of our terminals and pipelines are located on or near current or former refining and terminal sites, and there is a risk that contamination is present on those sites. We may be subject to strict, joint and several liability under a number of these environmental laws and regulations for such disposal and releases of hydrocarbons or solid wastes or the existence of contamination, even in circumstances where such activities or conditions were caused by third parties not under our control or were otherwise lawful at the time they occurred.

The laws and regulations that affect our operations, and the enforcement thereof, have become increasingly stringent over time. We cannot ensure that these laws and regulations will not be further revised or that new laws or regulations will not be adopted or become applicable to us. There can be no assurance as to the amount or timing of future expenditures to comply with laws and regulations, including expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. We also face risks from political activists and protesters, who may attempt to delay pipeline construction through protests, sabotage and other means. In addition to increasing our costs or liabilities, legal or regulatory changes or changes in the cost or availability of permits or related credits, where applicable, could also impact our ability to develop new projects. For example, changes that affect permitting or siting processes or the use of eminent domain could prevent or delay our ability to construct new pipelines or storage tanks. Revised or additional regulations that result in increased compliance costs or additional operating restrictions or liabilities could have a material adverse effect on our business, financial position, results of operations and prospects.

The Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011 increased penalties for safety violations, established additional safety requirements for newly-constructed pipelines and required studies of certain safety issues that could result in the adoption of new regulatory requirements for existing pipelines. PHMSA is currently in the process of formalizing modifications to existing hazardous liquid pipeline regulation which is expected to be issued in 2019. It is possible that new legislation and more stringent regulations could be adopted to enhance pipeline safety. Compliance with such legislative and regulatory changes could increase our compliance costs and have a material adverse effect on our results of operations.

Our customers are also subject to extensive laws and regulations that affect their businesses, and new laws or regulations could materially adversely affect their businesses or prospects. For example, several of our most significant customers are refineries whose businesses could be significantly impacted by changes in environmental

or health-related laws or regulations. In addition, we have made and continue to make significant investments in crude oil and condensate storage and transportation projects that serve customers who largely depend on production techniques, such as hydraulic fracturing, that are currently being scrutinized by some governmental authorities and have encountered political opposition that could result in increased regulatory costs or delays. For example, recent referendums in the state of Colorado, from where most of the volume on our Saddlehorn joint venture originates, sought to restrict hydraulic fracturing in that state. We are unable to predict the ultimate outcome of any such political activity in the future. Any changes in laws or regulations, or in the interpretation, implementation or enforcement of existing laws and regulations, that impose significant costs or liabilities on our customers, or that result in delays or cancellations of their projects, could reduce their demand for our services and materially adversely affect our results of operations, financial position or cash flows and our ability to pay cash distributions.

Climate change legislation or regulations restricting emissions of “greenhouse gases” could result in increased operating costs and reduced demand for the products that we transport, store or distribute.

The EPA has adopted regulations under existing provisions of the CAA that require certain large stationary sources to obtain pre-construction permits and operating permits for greenhouse gas emissions. In addition, in September 2009, the EPA issued a final rule requiring the monitoring and reporting of greenhouse gas emissions from certain large greenhouse gas emissions sources. This reporting rule was expanded in November 2010 to include petroleum facilities.

Federal and state legislative and regulatory initiatives, as well as those in other countries, may attempt to further address climate change or control or limit greenhouse gas emissions. Although it is not possible to predict how they would impact our business, any such future laws or regulations could adversely affect demand for the products that we transport, store and distribute. Depending on the particular programs adopted, they could also increase our costs to operate and maintain our facilities by requiring that we measure and report our emissions, install new emission controls on our facilities, acquire allowances to authorize our emissions, pay taxes related to our emissions and administer and manage an emissions program, among other things. We may be unable to include some or all of such increased costs in the rates charged to our customers and any such recovery may depend on events beyond our control, including the outcome of future rate proceedings before the FERC or state regulatory agencies and the provisions of any final legislation or implementing regulations.

Finally, certain scientific studies conclude that increasing concentrations of greenhouse gases in the Earth’s atmosphere may affect climate changes, which could result in the increased frequency and severity of storms, floods and other climatic events. If any such effects occur, there may be adverse effects on our assets and operations.

Our butane blending activities subject us to federal regulations that govern renewable fuel requirements in the United States.

The Energy Independence and Security Act of 2007 expanded the required use of renewable fuels in the United States. Each year, the EPA establishes an RVO requirement for refiners and fuel manufacturers based on overall quotas established by the federal government. By virtue of our butane blending activity and resulting gasoline production, we are an obligated party and receive an annual RVO from the EPA. In lieu of blending renewable fuels (such as ethanol and biodiesel), we typically purchase renewable energy credits, called RINs, to meet this obligation. RINs are generated when a gallon of biofuel such as ethanol or biodiesel is produced. RINs may be separated when the biofuel is blended into gasoline or diesel, at which point the RIN is available for use in compliance or is available for sale on the open market. Increases in the cost or decreases in the availability of RINs could have an adverse impact on our results of operations, cash flows and cash distributions.

Our business is subject to federal, state, local and international laws and regulations that govern the product quality specifications of the petroleum products that we store, transport or sell.

Petroleum products that we store and transport are sold by our customers for consumption into the public market. Various federal, state and local agencies, as well as international regulatory bodies such as the International Maritime Organization (“IMO”), have the authority to prescribe specific product quality specifications for

commodities sold into the public market. Changes in product quality specifications or blending requirements, such as the limits on the sulfur content of bunker fuels required by IMO for implementation in 2020, could reduce demand, reduce our throughput volume, require us to incur additional handling costs or require capital expenditures. For instance, different product specifications for different markets impact the fungibility of the products in our system and could require the construction of additional storage. If we are unable to recover these costs through increased revenue, our cash flows and ability to pay cash distributions could be materially adversely affected.

In addition, changes in the product quality of the products we receive on our refined products pipeline, or changes in the product specifications in the markets we serve, could reduce or eliminate our ability to blend products, which would result in a reduction of our revenue and operating profit from blending activities. Any such reduction of our revenue or operating profit could have a material adverse effect on our results of operations, financial position, cash flows and ability to pay cash distributions.

Our butane blending activities are the subject of a request for a new rulemaking by the FERC and have been challenged in litigation.

In February 2018, two associations representing shippers on interstate liquids pipelines petitioned the FERC for a broad new rulemaking with respect to interactions between pipeline companies and their affiliates. Among other claims, petitioners allege that blending activities conducted by pipelines are discriminatory. In particular, petitioners made reference to a pending lawsuit against Colonial Pipeline Company (“Colonial”) and our joint venture with Colonial, Powder Springs, in which the plaintiff has claimed that blending of refined products shipped on a pipeline by the pipeline company or its affiliate constitutes conversion of the shipper’s property and is barred by the Carmack Amendment, which governs claims for damage or loss incurred to goods transported by a carrier in interstate commerce. We have historically generated significant product margins from other blending activities on our refined products pipeline system. If the shipper’s claims are successful or if the FERC adopts new rules or regulations that inhibit or prohibit the blending activities of Powder Springs or of the refined products industry more broadly, our investment in Powder Springs could be impaired and the product margin we earn from these activities could be significantly reduced, which would adversely affect our profitability, our financial position and our ability to make distributions.

Our business could be affected adversely by union disputes and strikes or work stoppages by our unionized employees.

As of December 31, 2018, approximately 14% of our workforce was covered by two collective bargaining agreements with different terms and dates of expirations. We could experience a work stoppage in the future as a result of disagreements with these labor unions. A prolonged work stoppage could have a material adverse effect on our business activities, results of operations and cash flows.

Skills and institutional knowledge possessed by our current employees may be difficult to retain, and our growth strategy depends in part on our ability to recruit and retain employees with appropriate skills.

A significant percentage of our employees, including much of our management team, will become eligible for retirement over the next several years. Many of those employees have skills and institutional knowledge that have been developed over many years of service. As these employees reach retirement age, we may be unable to replace them with employees with comparable knowledge and experience, and we may be unable to transfer their knowledge successfully to new qualified employees. In addition, our growth strategy requires that we hire additional employees with the skills required to develop and operate our assets. For example, our crude oil segment has experienced rapid growth in recent years, and we continue to make significant investments in each of our operating segments. If we are unable to transfer knowledge successfully to new employees or are otherwise unable to recruit and retain sufficiently

talented personnel, we could experience increased costs, our growth strategy could be slowed or we could encounter other difficulties in running our business efficiently.

An impairment of long-lived assets, investments in non-controlled entities, goodwill or other intangibles could reduce our earnings and negatively impact the value of our limited partner units.

At December 31, 2018, we had \$5.8 billion of net property, plant and equipment, \$1.1 billion of investments in non-controlled entities, \$53.3 million of goodwill and \$51.2 million of other intangibles. U.S. GAAP requires us to periodically test long-lived assets, investments in non-controlled entities, goodwill and other intangibles for impairment. For example, in the current period we made the decision to discontinue commercial operations of our ammonia pipeline due to the system's low profitability and challenging economic outlook and recognized a \$49.1 million impairment charge. If we were to determine that any of our long-lived assets, investments in non-controlled entities, goodwill or other intangibles were impaired, we would be required to take an immediate charge to earnings with a corresponding reduction of partners' equity. Such charges could be material to our results of operations and could adversely impact the value of our limited partner units.

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

Unitholders' voting rights are restricted by a provision in our partnership agreement stating that any units held by a person that owns 20% or more of any class of our common units then outstanding, other than our general partner and its affiliates, cannot be voted on any matter. In addition, our partnership agreement contains provisions limiting the ability of unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting our unitholders' ability to influence our management. As a result of this provision, the trading price of our common units may be lower than other forms of equity ownership due to the absence of a takeover premium in the trading price.

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

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

• Our unitholders' rights 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 constitute "control" of our business.

Our general partner's board of directors' absolute discretion in determining our level of cash reserves may adversely affect our ability to make cash distributions to our unitholders.

Our partnership agreement requires our general partner's board of directors to deduct from available cash the amount of any cash reserves that in its reasonable discretion are necessary to fund our future operating expenditures. In addition, the partnership agreement permits our general partner's board of directors to reduce available cash by establishing cash reserves for the proper conduct of our business, to comply with applicable laws or agreements to which we are a party or to provide funds for future distributions to partners. Any such cash reserves will reduce the amount of cash currently available for distribution to our unitholders.

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

Our partnership agreement contains provisions that eliminate the fiduciary standards to which our general partner and its officers and directors would otherwise be held by state fiduciary law and replaces those duties with

several different contractual standards. For example, our partnership agreement permits our general partner to make a number of decisions in its sole discretion, free of any duties to us and holders of our limited partner units other than the implied contractual covenant of good faith and fair dealing. This provision entitles our general partner to consider only the interests and factors that it desires and relieves it of any duty or obligation to give any consideration to any interest of, or factors affecting, us or our limited partners. In addition, our partnership agreement grants broad rights of indemnification to our general partner and its officers and directors. By owning a limited partner unit, a holder is treated as having consented to the provisions in our partnership agreement.

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

Our partnership agreement contains provisions that restrict the remedies available to holders of our limited partner units 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 is permitted or required to make a decision, in its capacity as our general partner, our general partner is permitted or required to make such a decision 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;

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 if our general partner or its officers and directors, as the case may be, taken in good faith; and

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

Limited partner units held by persons who are not citizenship-eligible may be subject to redemption.

Our partnership agreement contains provisions that apply if we determine that the nationality, citizenship or other related status of a holder of our limited partnership units creates a substantial risk of cancellation or forfeiture of any property in which we have an interest. If a holder of our limited partner units is not a person who meets the requirements to be a citizenship-eligible holder, which generally includes U.S. entities and individuals who are U.S. citizens, and, therefore, creates a risk to the partnership, the holder may have its limited partner units redeemed by us. In addition, if a holder of our limited partner units does not meet the requirements to be a citizenship-eligible holder, such holder will not be entitled to voting rights and may not receive distributions in kind upon our liquidation.

Tax Risks to Limited Partner Unitholders

Our tax treatment depends on our status as a partnership for federal income tax purposes. If the IRS were to treat us as a corporation for federal income tax purposes, or otherwise subject us to entity-level taxation, it would reduce the amount of cash available for distribution to our unitholders.

The anticipated after-tax economic benefit of an investment in our limited partner units depends largely on our being treated as a partnership for federal income tax purposes.

Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. A change in our business or a change in current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is a maximum of 21%, and would likely pay state income tax at varying rates. Payments to our unitholders would generally be taxed again as corporate dividends, 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 distribution to our unitholders would be substantially reduced over time. 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 limited partner units.

Our tax treatment or the tax treatment of our unitholders could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

Current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. From time to time the U.S. government considers substantive changes to the existing federal income tax laws that affect publicly traded partnerships. On December 22, 2017, President Trump signed into law H.R. 1 (commonly referred to as the “Tax Cuts and Jobs Act,” or the “TCJA”), a comprehensive tax reform bill that significantly reforms the Internal Revenue Code of 1986, as amended. The TCJA did not impact our treatment as a partnership for federal income tax purposes; however, the TCJA did provide for significant changes to the taxation of our operations and to an investment in our limited partner units, including, among other changes, a new individual deduction for our unitholders relating to certain income from partnerships. Many of the provisions in the TCJA, including the deduction related to certain income from partnerships, are temporary and, without additional legislation, will sunset on December 31, 2025. We are unable to predict whether any such additional legislation or any other tax-related proposals will ultimately be enacted. Moreover, any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Any such changes could negatively impact a unitholder’s investment in our limited partner units.

At the state level, changes in current state law may subject us to additional entity-level taxation by individual states. States frequently evaluate ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of any such taxes may materially reduce the cash available for distribution to our unitholders.

If the IRS contests the federal income tax positions we take, the market for our limited partner units may be adversely impacted and the cost of any IRS contest will reduce our cash available for distribution to our unitholders.

The IRS has made no determination as to our status as a partnership for federal income tax purposes. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of the positions we take. Any contest with the IRS may materially and adversely impact the market for our limited partner units and the price at which they trade. In addition, our costs of any contest with the IRS will be borne indirectly by our unitholders as the costs will reduce our cash available for distribution.

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

Because our unitholders will be treated as partners to whom we will allocate taxable income which could be different in amount than the cash we distribute, our unitholders will be required to pay any federal income taxes and, in some cases, state and local income taxes on their share of our taxable income even if they receive no cash distributions from us. Our unitholders may not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability that results from that income.

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

If our unitholders sell their limited partner units, they will recognize a gain or loss equal to the difference between the amount realized and their tax basis in those limited partner units. Prior distributions to our unitholders in excess of the total net taxable income they were allocated for a limited partner unit, which decreased their tax

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basis in that limited partner unit, will, in effect, become taxable income to our unitholders if the limited partner unit is sold at a price greater than their tax basis in that limited partner unit, even if the price they receive is less than their original cost. A substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder's share of nonrecourse liabilities, if our unitholders sell their limited partner units, they may incur a tax liability in excess of the amount of cash received from the sale.

Tax-exempt entities and foreign persons face unique tax issues from owning our limited partner units that may result in adverse tax consequences to them.

Investment in limited partner units by tax-exempt entities, such as employee benefit plans, individual retirement accounts (known as IRAs) and foreign persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to foreign persons will be reduced by withholding taxes at the highest applicable effective tax rate, and foreign persons will be required to file U.S. federal tax returns and pay tax on their share of our taxable income. Upon the sale, exchange or other disposition of a limited partner unit by a foreign unitholder, the transferee is generally required to withhold 10% of the amount realized on such sale, exchange or other disposition if any portion of the gain on such sale, exchange or other disposition would be treated as effectively connected with a U.S. trade or business. If the transferee fails to satisfy this withholding requirement, we will be required to deduct and withhold such amount (plus interest) from future distributions to the transferee. Because the "amount realized" would include a unitholder's share of our nonrecourse liabilities, 10% of the amount realized could exceed the total cash purchase price for such disposed units. Due to this fact, our inability to match transferors and transferees of units, and other uncertainty surrounding the application of these withholding rules, the U.S. Department of the Treasury and the IRS have currently suspended these rules for transfers of certain publicly traded partnership interests, including transfers of our units, until regulations or other guidance has been issued. It is unclear when such regulations or other guidance will be issued. Tax-exempt entities or foreign persons should consult their tax advisor before investing in our limited partner units.

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

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

The IRS may challenge aspects of our proration method, and, if successful, we would be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction between transferors and transferees of our limited partner units each month based upon the ownership of our limited partner units on the first business day of each month, instead of on the basis of the date a particular unit is transferred. The U.S. Department of Treasury and the IRS issued Treasury Regulations that permit publicly traded partnerships to use a monthly simplifying convention that is similar to ours, but they do not specifically authorize all aspects of the proration method we have adopted. If the IRS were to successfully challenge this method, we could be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose limited partner units are loaned to a “short seller” to cover a short sale of limited partner units may be considered to have disposed of those limited partner units. If so, he would no longer be treated for tax purposes as a partner with respect to those limited partner units during the period of the loan and may recognize gain or loss from the disposition.

Because a unitholder whose limited partner units are loaned to a “short seller” to cover a short sale of limited partner units may be considered to have disposed of the loaned limited partner units, the unitholder may no longer be treated for tax purposes as a partner with respect to those limited partner units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those limited partner units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those limited partner 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 loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their limited partner 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, and such a challenge could adversely affect the value of our limited partner units.

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

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

Our unitholders may be subject to state and local taxes and return filing requirements in states where they do not live as a result of investing in our limited partner units.

In addition to federal income taxes, our unitholders may be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if they do not live in any of those jurisdictions. Our unitholders may be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. We currently own assets and conduct business in 25 states, most of which impose a personal income tax. As we make acquisitions or expand our business, we may own assets or conduct business in additional states that impose a personal income tax.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after December 31, 2017, it may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us, in which case our cash available for distribution to our unitholders might be substantially reduced.

Pursuant to the Bipartisan Budget Act of 2015, for tax years beginning after December 31, 2017, if the IRS makes audit adjustments to our income tax returns, it may assess and collect any taxes (including any applicable penalties

and interest) resulting from such audit adjustment directly from us. Generally, we expect to elect to have our unitholders take such audit adjustment into account in accordance with their interests in us during the tax year under audit, but there can be no assurance that such election will be made, or applicable, in all circumstances. If we are unable to have our unitholders take such audit adjustment into account in accordance with their interests in us

during the tax year under audit, our current unitholders may bear some or all of the economic burden 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.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

See Item 1(c) for a description of the locations and general character of our material properties.

Item 3. Legal Proceedings

Butane Blending Patent Infringement Proceeding. On October 4, 2017, Sunoco Partners Marketing & Terminals L.P. (“Sunoco”) brought an action for patent infringement in the U.S. District Court for the District of Delaware alleging Magellan Midstream Partners, L.P. (“Magellan”) and Powder Springs Logistics, LLC (“Powder Springs”) have infringed patents relating to butane blending at the Powder Springs facility located in Powder Springs, Georgia. Sunoco has since submitted pleadings alleging that Magellan has also infringed various patents relating to butane blending at nine Magellan facilities, in addition to Powder Springs. Sunoco is seeking an undetermined amount of damages, attorneys’ fees and a permanent injunction enjoining Magellan and Powder Springs from infringing on the subject patents. We deny and are vigorously defending against all claims asserted by Sunoco. Although it is not possible to predict the ultimate outcome, we believe, based on our current understanding of the applicable facts and law, that the ultimate resolution of this matter will not have a material adverse impact on our results of operations, financial position or cash flows.

Hurricane Harvey Enforcement Proceeding. On July 10, 2018, we received a Notice of Enforcement letter from the Texas Commission on Environmental Quality alleging two air emission violations at our Galena Park, Texas terminal that occurred during Hurricane Harvey in third quarter 2017. The penalties associated with these alleged violations could exceed \$100,000. While the results cannot be predicted with certainty, we believe the ultimate resolution of this matter will not have a material impact on our results of operations, financial position or cash flows.

Clean Air Act Enforcement Proceeding. In June 2017, we received an enforcement letter from the U.S. Department of Justice (“DOJ”) regarding a referral from the U.S. Environmental Protection Agency (“EPA”) relating to alleged Clean Air Act violations at our terminals in Mason City, Iowa, Great Bend and Kansas City, Kansas and Omaha, Nebraska. In 2018, the DOJ and EPA notified us of their intent to impose penalties as a result of these alleged violations which could exceed \$100,000. We have been in active settlement discussions with the DOJ and EPA to settle these alleged violations on terms that are mutually agreeable. While the results cannot be predicted with certainty, we believe the ultimate resolution of this matter will not have a material impact on our results of operations, financial position or cash flows.

U.S. Oil Recovery, EPA ID No.: TXN000607093 Superfund Site. We have liability at the U.S. Oil Recovery Superfund Site in Pasadena, Texas as a potential responsible party (“PRP”) under Section 107(a) of the Comprehensive Environmental Response, Compensation, and Liability Act (“CERCLA”). As a result of the EPA’s Administrative Settlement Agreement and Order on Consent for Removal Action, filed August 25, 2011, EPA Region 6, CERCLA Docket No. 06-10-11, we voluntarily entered into the PRP group responsible for the site investigation, stabilization and subsequent site cleanup. We have paid approximately \$42,000 associated with the assessment phase. Until this assessment phase has been completed, we cannot reasonably estimate our proportionate share of the remediation costs associated with this site. While the results cannot be reasonably estimated, we believe the ultimate resolution of this matter will not have a material impact on our results of operations, financial position or cash flows.

Lake Calumet Cluster Site, EPA ID No.: ILD000716852 Superfund Site. We have liability at the Lake Calumet Cluster Superfund Site in Chicago, Illinois as a PRP under Sections 107(a) and 113(f)(1) of CERCLA. As a result of the EPA’s Administrative Settlement Agreement and Order for Remedial Investigation/Feasibility Study of June 2013, we voluntarily entered into the PRP group responsible for the investigation, cleanup and installation of an appropriate clay cap over the site. We have paid approximately \$9,000 associated with the Remedial Investigation/Feasibility Study and cleanup costs to date. Our projected portion of the estimated cap installation is \$55,000. While the results cannot be predicted with certainty, we believe the ultimate resolution of this matter will not have a material impact on our results of operations, financial position or cash flows.

We are a party to various other claims, legal actions and complaints arising in the ordinary course of business. While the results cannot be predicted with certainty, management believes the ultimate resolution of these claims, legal actions and complaints after consideration of amounts accrued, insurance coverage or other indemnification

arrangements will not have a material adverse effect on our future results of operations, financial position or cash flows.

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 limited partner units representing limited partnership interests are listed and traded on the New York Stock Exchange under the ticker symbol "MMP." At the close of business on February 13, 2019, we had 228,403,428 limited partner units outstanding that were owned by approximately 166,000 record holders and beneficial owners (held in street name).

For information regarding limited partner units that may be issued pursuant to our long-term incentive plan, see Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

We currently pay quarterly cash distributions of \$0.9975 per limited partner unit. In general, we intend to increase our cash distribution; however, we cannot guarantee that future distributions will increase or continue at current levels.

Unitholder Return Performance Presentation

The following graph compares the total unitholder return performance of our limited partner units with the performance of (i) the Standard & Poor's 500 Stock Index ("S&P 500"), (ii) the Alerian MLP Index ("AMZ") and (iii) the Alerian MLP Infrastructure Index ("AMZI"). The graph assumes that \$100 was invested in our limited partner units and each comparison index beginning on December 31, 2013 and that all distributions or dividends were reinvested on a quarterly basis.

We used the AMZ from 2009 to 2018 because it represented a composite index of the most prominent energy master limited partnerships. The AMZI is also a composite of energy infrastructure master limited partnerships, whose constituents earn the majority of their cash flow from midstream activities involving energy commodities and whose trading volume and market capitalization meet certain additional criteria. We intend to use the AMZI as our peer index for future unitholder return comparisons because we believe the constituent criteria of the AMZI makes it more comparable to the size and nature of our own business than the AMZ. In addition, the compensation committee of our general partner's board of directors selected the constituents of the AMZI as the peer group for the total unitholder return relative performance portion of the performance-based awards issued under our long-term incentive compensation plan, and we believe it is preferable to use the same index for our performance graph as our compensation committee uses for purposes of determining performance under that plan.

	12/31/2013	12/31/2014	12/31/2015	12/31/2016	12/31/2017	12/31/2018
Magellan Midstream Partners, L.P.	\$100	\$135	\$115	\$135	\$133	\$113
Alerian MLP Infrastructure Index (AMZI)	\$100	\$108	\$73	\$87	\$80	\$70
Alerian MLP Index (AMZ)	\$100	\$105	\$71	\$84	\$78	\$68
S&P 500	\$100	\$114	\$115	\$129	\$157	\$150

The information provided in this section is being furnished to and not filed with the SEC. As such, this information is neither subject to Regulation 14A or 14C nor to the liabilities of Section 18 of the Exchange Act.

Item 6. Selected Financial Data

We have derived the summary selected historical financial data from our current and historical accounting records. Information concerning significant trends in our financial condition and results of operations is contained in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

Our operating results incorporate a number of significant estimates and uncertainties. Such matters could cause the data included herein not to be indicative of our future financial condition or results of operations. A discussion of our critical accounting estimates and how these estimates could impact our future financial condition or results of operations is included in Management's Discussion and Analysis of Financial Condition and Results of Operations under Item 7 of this report. In addition, a discussion of the risk factors that could affect our business and future financial condition or results of operations is included under Item 1A. Risk Factors of this report. Additionally, the notes to our financial statements under Item 8. Financial Statements and Supplementary Data of this report include descriptions of areas where estimates and judgments could result in different amounts being recognized in our accompanying consolidated financial statements.

We believe that investors benefit from having access to the same financial measures utilized by management. In the following tables, we present the financial measure of distributable cash flow ("DCF"), which is not a generally accepted accounting principles ("GAAP") measure. Our partnership agreement requires that all of our available cash, less amounts reserved by our general partner's board of directors, be distributed to our limited partners. Management uses DCF to determine the amount of cash that our operations generated that is available for distribution to our limited partners and as a basis for recommending to our general partner's board of directors the amount of cash distributions to be paid each period. We also use DCF as the basis for calculating our equity-based long-term incentive compensation. A reconciliation of DCF to net income, the nearest comparable GAAP measure, is included in the following tables.

In addition to DCF, the non-GAAP measures of operating margin (in the aggregate and by segment) and Adjusted EBITDA are presented in the following tables. We compute the components of operating margin and Adjusted EBITDA using amounts that are determined in accordance with GAAP. A reconciliation of operating margin to operating profit and net income to Adjusted EBITDA, which are the nearest comparable GAAP financial measures, are included in the following tables. See Note 15 – Segment Disclosures under Item 8. Financial Statements and Supplementary Data of this report for a reconciliation of segment operating margin to segment operating profit. Operating margin is an important measure of the economic performance of our core operations. Operating profit, alternatively, includes depreciation, amortization and impairment expense and general and administrative ("G&A") expense that management does not focus on when evaluating the core profitability of an operation. Adjusted EBITDA is an important measure utilized by management and the investment community to assess the financial results of an entity.

Since the non-GAAP measures presented here include adjustments specific to us, they may not be comparable to similarly-titled measures of other companies.

	Year Ended December 31,				
	2014	2015	2016	2017	2018
	(in thousands, except per unit amounts)				
Income Statement Data:					
Transportation and terminals revenue	\$1,459,267	\$1,544,746	\$1,591,119	\$1,731,775	\$1,878,988
Product sales revenue	878,974	629,836	599,602	758,206	927,220
Affiliate management fee revenue	22,111	13,871	14,689	17,680	20,365
Total revenue	2,360,352	2,188,453	2,205,410	2,507,661	2,826,573
Operating expenses	499,053	523,650	528,672	577,978	649,436
Cost of product sales	594,585	447,273	493,338	635,617	704,313
Subtotal	1,266,714	1,217,530	1,183,400	1,294,066	1,472,824
Earnings of non-controlled entities	19,394	66,483	78,696	120,994	181,117
Operating margin	1,286,108	1,284,013	1,262,096	1,415,060	1,653,941
Depreciation, amortization and impairment expense	161,741	166,812	178,142	196,630	265,077
G&A expense	147,203	149,948	147,165	165,717	194,283
Operating profit	977,164	967,253	936,789	1,052,713	1,194,581
Interest expense, net	121,519	143,177	165,410	193,718	200,514
Gain on disposition of assets	—	—	(28,144)	(18,505)	(353,797)
Other (income) expense	11,506	2,618	(6,466)	4,139	13,868
Income before provision for income taxes	844,139	821,458	805,989	873,361	1,333,996
Provision for income taxes	4,620	2,336	3,218	3,830	71
Net income	\$839,519	\$819,122	\$802,771	\$869,531	\$1,333,925
Basic net income per limited partner unit	\$3.69	\$3.60	\$3.52	\$3.81	\$5.84
Diluted net income per limited partner unit	\$3.69	\$3.59	\$3.52	\$3.81	\$5.84
Balance Sheets Data:					
Working capital (deficit) ^(a)	\$(133,488)	\$(374,218)	\$(111,262)	\$(239,899)	\$(30,213)
Total assets	\$5,501,409	\$6,041,567	\$6,772,073	\$7,394,375	\$7,747,537
Long-term debt, net	\$2,967,019	\$3,189,287	\$4,087,192	\$4,273,518	\$4,211,380
Partners' capital	\$1,868,233	\$2,021,736	\$2,092,105	\$2,129,653	\$2,643,434
Cash Distribution Data:					
Cash distributions declared per unit ^(b)	\$2.62	\$3.01	\$3.32	\$3.59	\$3.87
Cash distributions paid per unit ^(b)	\$2.51	\$2.92	\$3.25	\$3.52	\$3.79

	Year Ended December 31,				
	2014	2015	2016	2017	2018
	(in thousands, except operating statistics)				
Other Data:					
Operating margin:					
Refined products	\$871,492	\$778,515	\$723,588	\$825,746	\$966,753
Crude oil	296,132	381,819	408,327	465,386	563,340
Marine storage	114,971	119,828	125,226	118,654	117,901
Allocated partnership depreciation costs ^(c)	3,513	3,851	4,955	5,274	5,947
Operating margin	\$1,286,108	\$1,284,013	\$1,262,096	\$1,415,060	\$1,653,941
Adjusted EBITDA and distributable cash flow:					
Net income	\$839,519	\$819,122	\$802,771	\$869,531	\$1,333,925
Interest expense, net	121,519	143,177	165,410	193,718	200,514
Depreciation, amortization and impairment ^(d)	161,741	166,812	178,142	196,630	256,130
Equity-based incentive compensation ^(e)	12,471	6,461	4,982	6,766	22,768
Loss on sale and retirement of assets	7,223	7,871	11,190	13,370	16,392
Gain on disposition of assets ^(f)	—	—	(28,144)	(18,505)	(351,215)
Commodity-related adjustments ^(g)	(56,288)	13,988	64,257	12,463	(101,987)
Distributions received from non-controlled entities in excess of (less than) earnings for the period	(8,724)	14,572	9,293	25,216	15,584
Other ^(h)	—	—	5,341	3,749	3,644
Adjusted EBITDA	1,077,461	1,172,003	1,213,242	1,302,938	1,395,755
Interest expense, net, excluding debt issuance cost amortization					
	(119,186)	(140,464)	(162,251)	(190,403)	(197,274)
Maintenance capital ⁽ⁱ⁾	(77,806)	(88,685)	(103,507)	(91,163)	(88,736)
Distributable cash flow	\$880,469	\$942,854	\$947,484	\$1,021,372	\$1,109,745
Operating Statistics:					
Refined products:					
Transportation revenue per barrel shipped	\$1.399	\$1.439	\$1.473	\$1.495	\$1.556
Volume shipped (million barrels):					
Gasoline	256.1	268.1	275.4	295.5	286.9
Distillates	163.1	152.5	150.2	166.2	181.7
Aviation fuel	23.0	21.2	25.7	26.5	31.0
Liquefied petroleum gases	9.9	9.7	10.4	9.9	11.0
Total volume shipped	452.1	451.5	461.7	498.1	510.6
Crude oil:					
Magellan 100%-owned assets:					
Transportation revenue per barrel shipped	\$1.192	\$1.118	\$1.321	\$1.348	\$1.208
Volume shipped (million barrels)	185.5	209.9	187.0	196.4	242.8
Crude oil terminal average utilization (million barrels per month)	12.2	13.1	15.0	15.3	16.5
Select joint venture pipelines:					
BridgeTex - volume shipped (million barrels) ^(j)	18.3	75.2	79.0	98.4	138.2
Saddlehorn - volume shipped (million barrels) ^(k)	—	—	5.2	19.0	27.4
Marine storage:					

Marine terminal average utilization (million barrels per month)	22.9	24.0	23.8	23.1	22.7
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- (a) Working capital deficit at December 31, 2015 and 2017 included the current portion of long-term debt of approximately \$250 million for each period.
Cash distributions declared were determined based on DCF generated for each calendar year. Distributions were
- (b) declared and paid within 45 days following the close of each quarter. Cash distributions paid represent cash payments for distributions during each of the periods presented.
- (c) Certain depreciation expense was allocated to our various business segments, which in turn recognized these allocated costs as operating expense, reducing segment operating margin by these amounts.
- (d) In 2018, we recognized impairment costs of \$49.1 million related to the ammonia pipeline system, of which \$8.9 million represents cash requirements to decommission the pipeline and is deducted from DCF.
Because we intend to satisfy vesting of unit awards under our equity-based long-term incentive compensation plan with the issuance of limited partner units, expenses related to this plan generally are deemed non-cash and added
- (e) back for DCF purposes. However, the amounts above have been reduced by cash payments associated with the plan, which are primarily related to tax withholdings.
- (f) Gains on asset dispositions are not related to ongoing operations and as such, are subtracted from DCF. The amounts above are net of purchase price adjustments that are related to operations.
- (g) See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Distributable Cash Flow for a description of items included in our commodity-related adjustments.
Other adjustments in 2018 include a \$3.6 million adjustment recorded to partners' capital as required by our adoption of Accounting Standards Update 2014-09, Revenue from Contracts with Customers. The amount represents cash that we had previously received for deficiency payments but did not yet recognize in net income
- (h) under the previous revenue recognition standard. Other adjustments in 2016 and 2017 include payments received from HollyFrontier Corporation in conjunction with the February 2016 Osage Pipe Line Company, LLC ("Osage") exchange transaction. These payments replaced distributions we would have received had the Osage transaction not occurred and are, therefore, included in our calculation of DCF.
Maintenance capital expenditure projects maintain our existing assets and do not generate incremental DCF (i.e.
- (i) incremental returns to our unitholders). For this reason, we deduct maintenance capital expenditures to determine DCF.
- (j) These volumes reflect the total shipments for the BridgeTex pipeline, which began operations in September 2014 and was owned 50% by us through September 28, 2018 and 30% thereafter.
- (k) These volumes reflect the total shipments for the Saddlehorn pipeline, which is owned 40% by us and began operations in September 2016.

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

Introduction

We are a publicly traded limited partnership principally engaged in the transportation, storage and distribution of refined petroleum products and crude oil. As of December 31, 2018, our asset portfolio consisted of:

our refined products segment, comprised of our approximately 9,700-mile refined products pipeline system with 53 terminals as well as 25 independent terminals not connected to our pipeline system and our 1,100-mile ammonia pipeline system;

our crude oil segment, comprised of approximately 2,200 miles of crude oil pipelines, our condensate splitter and 33 million barrels of aggregate storage capacity, of which 21 million barrels are used for contract storage. Approximately 1,000 miles of these pipelines and 28 million barrels of this storage capacity (including 19 million barrels used for contract storage) are wholly-owned and the remainder is owned through joint ventures; and

our marine storage segment, consisting of six marine terminals located along coastal waterways with an aggregate storage capacity of approximately 27 million barrels. Five of these terminals and approximately 25 million barrels of this storage capacity are wholly-owned, and the remainder is owned through joint ventures.

The following discussion and analysis should be read in conjunction with our consolidated financial statements and related notes included in this annual report on Form 10-K for the year ended December 31, 2018.

See Item 1. Business for a detailed description of our business.

Overview

Our assets are an integral part of our nation's energy infrastructure, and we provide essential services to the markets we serve. Our straight-forward business model is primarily focused on fee-based transportation and terminal services, moving the fuel that moves America.

Our refined products pipeline system moved record diesel fuel shipments to meet growing demand in crude oil production regions, especially in west Texas. Based on U.S. government projections, demand for refined products is expected to remain relatively stable over the next decade in the markets we serve. Our pipeline system runs through the heart of the U.S., from Texas to North Dakota, serving both growing urban demand centers and important agricultural regions.

The crude oil market continues to be dynamic, especially in the prolific Permian Basin region that serves as the origin for our wholly-owned Longhorn and joint venture BridgeTex pipelines. Our 2018 results benefited from increased capacity on the BridgeTex pipeline system due to a recent expansion and the favorable pricing differential between the Permian Basin and Houston that encouraged shipments above contracted levels on both pipelines during much of the year, resulting in record annual shipments.

Dynamic markets provide both opportunities and challenges. Because of increased production in the Permian, more pipeline take-away capacity is being built, increasing competition in the basin. During late 2018, the initial contract terms for our Longhorn pipeline expired, and we successfully renewed or extended these contracts with all of our original customers, emphasizing the importance of this asset to the industry. However, due to the more competitive environment, our average Longhorn tariff rates are now lower but still generate attractive returns.

The dynamic environment has also brought interest from outside parties to invest in the region. As a result, we were presented with the opportunity to sell a 20% interest in BridgeTex during late 2018 at what we considered to be

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an attractive valuation. We still own a 30% interest in BridgeTex and remain the operator of this pipeline system. This investment continues to play a strategic part in our Texas crude oil business as it connects to our East Houston terminal, which is becoming a significant trading hub for the U.S. Gulf Coast. Further, we expect BridgeTex to play an important role in our other growth initiatives in Houston and beyond. Ultimately, the \$575 million of proceeds from the sale will be reinvested into additional growth projects to benefit our future.

Capital Discipline

We have become known for our disciplined approach to growth and management of our company. In addition to launching new projects for our future growth, we continue to analyze our asset portfolio to ensure capital discipline in all aspects of our business. As a result, we have decided to discontinue the operation of our ammonia pipeline system later this year due to its low profitability and challenging economic outlook. We are also no longer pursuing our Delaware Basin crude oil pipeline construction project on a stand-alone basis and are actively evaluating a lower cost solution to meet the needs of our customers. These decisions demonstrate our commitment to manage all aspects of our business in a disciplined manner.

Growth Projects

Additional energy infrastructure to support our nation's growing export needs remains an important theme for our industry. We have made significant progress to advance our strategy to grow our marine capabilities along the Gulf Coast for both crude oil and refined products.

Our Seabrook joint venture initiated its first crude oil export in August 2018, and we announced plans to further expand this terminal with additional storage and dock capabilities. We believe the export options provided through Seabrook increases the attractiveness of our service offering to seamlessly deliver crude oil from the Permian Basin to the Gulf Coast waterway to meet our customers' growing interest in crude exports.

The first phase of our newly constructed MVP joint venture marine terminal in Pasadena, Texas became operational in January 2019 to meet our customers' increasing desire for refined products storage and export solutions. We continue to make significant progress on the next phase of the terminal at Pasadena, with an additional 4 million barrels of storage and additional dock capabilities expected to come online by the end of 2019. Discussions with a number of industry participants continue for additional infrastructure needs at this new facility. We remain optimistic about future expansions at Pasadena that could double the capacity of this new marine terminal.

Industry demand for additional pipeline infrastructure continues as well, and construction is underway for a new refined products pipeline segment in Central Texas that will expand capacity between Houston and the Dallas-Ft. Worth metropolitan area. This new pipeline segment is expected to be in-service during mid-2019. We are also expanding the western leg of our Texas refined products pipeline by mid-2020. Our Texas refined products pipeline system has been oversubscribed for quite some time, and we are pleased to meet the industry's need for more capacity through these strategic enhancements to our essential refined products pipeline system.

In 2018, we also announced plans to form a new crude oil pipeline joint venture with Energy Transfer, MPLX and Delek to deliver crude oil from the Permian Basin to our terminal in the Houston area and Energy Transfer's terminal in Nederland, Texas. This Permian Gulf Coast ("PGC") pipeline is intended to serve the Gulf Coast refining complex from Texas to Louisiana as well as multiple crude oil export facilities. While advancing the PGC stand-alone project, we also remain in discussions with other industry players to assess the potential to combine similar projects to capture capital and operating efficiencies that may be available for all parties.

Recent Developments

Cash Distribution. In January 2019, the board of directors of our general partner declared a quarterly cash distribution of \$0.9975 per unit for the period of October 1, 2018 through December 31, 2018. This quarterly cash distribution was paid on February 14, 2019 to unitholders of record on February 7, 2019. The total distribution paid on 228.4 million limited partner units outstanding was \$227.8 million.

Debt Issuance. In January 2019, we issued \$500.0 million of 4.85% senior notes due 2049 in an underwritten public offering. The notes were issued at 99.371% of par. Net proceeds from this offering were approximately \$492.5 million after underwriting discounts. The net proceeds from this offering along with cash on hand were used to redeem our 6.55% senior notes due 2019, which were paid on February 11, 2019.

Ammonia Pipeline. In December 2018, we made the decision to discontinue commercial operations of our ammonia pipeline beginning in late 2019 due to the system's low profitability and challenging economic outlook. As a result, we have recognized a \$49.1 million impairment charge.

Results of Operations

We believe that investors benefit from having access to the same financial measures utilized by management. Operating margin, which is presented in the following tables, is an important measure used by management to evaluate the economic performance of our core operations. Operating margin is not a generally accepted accounting principles ("GAAP") measure, but the components of operating margin are computed using amounts that are determined in accordance with GAAP. A reconciliation of operating margin to operating profit, which is its nearest comparable GAAP financial measure, is included in the following tables. Operating profit includes expense items, such as depreciation, amortization and impairment expense and general and administrative ("G&A") expenses, which management does not focus on when evaluating the core profitability of our separate operating segments. Additionally, product margin, which management primarily uses to evaluate the profitability of our commodity-related activities, is provided in these tables. Product margin is a non-GAAP measure; however, its components of product sales revenue and cost of product sales are determined in accordance with GAAP. Our butane blending, fractionation and other commodity-related activities generate significant revenue. We believe the product margin from these activities, which takes into account the related cost of product sales, better represents its importance to our results of operations.

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Year Ended December 31, 2017 Compared to Year Ended December 31, 2018

	Year Ended		Variance		
	December 31, 2017	December 31, 2018	Favorable (Unfavorable)		
			\$ Change	% Change	
Financial Highlights (\$ in millions, except operating statistics)					
Transportation and terminals revenue:					
Refined products	\$1,096.0	\$1,152.0	\$ 56.0	5	%
Crude oil	458.5	549.8	91.3	20	%
Marine storage	180.7	180.9	0.2	—	%
Intersegment eliminations	(3.4)	(3.7)	(0.3)	(9)	%
Total transportation and terminals revenue	1,731.8	1,879.0	147.2	8	%
Affiliate management fee revenue	17.7	20.4	2.7	15	%
Operating expenses:					
Refined products	400.4	424.8	(24.4)	(6)	%
Crude oil	120.9	166.2	(45.3)	(37)	%
Marine storage	65.3	68.0	(2.7)	(4)	%
Intersegment eliminations	(8.6)	(9.6)	1.0	12	%
Total operating expenses	578.0	649.4	(71.4)	(12)	%
Product margin:					
Product sales revenue	758.2	927.2	169.0	22	%
Cost of product sales	635.6	704.3	(68.7)	(11)	%
Product margin	122.6	222.9	100.3	82	%
Earnings of non-controlled entities	121.0	181.1	60.1	50	%
Operating margin	1,415.1	1,654.0	238.9	17	%
Depreciation, amortization and impairment expense	196.7	265.1	(68.4)	(35)	%
G&A expense	165.7	194.3	(28.6)	(17)	%
Operating profit	1,052.7	1,194.6	141.9	13	%
Interest expense (net of interest income and interest capitalized)	193.7	200.5	(6.8)	(4)	%
Gain on disposition of assets	(18.5)	(353.8)	335.3	1,812	%
Other expense	4.1	13.9	(9.8)	(239)	%
Income before provision for income taxes	873.4	1,334.0	460.6	53	%
Provision for income taxes	3.9	0.1	3.8	97	%
Net income	\$869.5	\$1,333.9	\$ 464.4	53	%

Operating Statistics

Refined products:

Transportation revenue per barrel shipped

\$1.495 \$1.556

Volume shipped (million barrels):

Gasoline

295.5 286.9

Distillates

166.2 181.7

Aviation fuel

26.5 31.0

Liquefied petroleum gases

9.9 11.0

Total volume shipped

498.1 510.6

Crude oil:

Magellan 100%-owned assets:

Transportation revenue per barrel shipped

\$1.348 \$1.208

Volumes shipped (million barrels)

196.4 242.8

Crude oil terminal average utilization (million barrels per month)

15.3 16.5

Select joint venture pipelines:

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BridgeTex - volume shipped (million barrels) ^(a)	98.4	138.2
Saddlehorn - volume shipped (million barrels) ^(b)	19.0	27.4
Marine storage:		
Marine terminal average utilization (million barrels per month)	23.1	22.7

(a) These volumes reflect total shipments for the BridgeTex pipeline which was owned 50% by us through September 28, 2018 and 30% thereafter.

(b) These volumes reflect total shipments for the Saddlehorn pipeline, which is owned 40% by us.

Transportation and terminals revenue increased by \$147.2 million, resulting from:

an increase in refined products revenue of \$56.0 million. Shipments increased in the current period primarily due to stronger demand for distillate in crude oil production regions. The average rate per barrel in the current period was favorably impacted by the mid-year 2017 and 2018 tariff adjustments. In addition, higher storage and other ancillary fees in 2018 resulting from increased customer activity were partially offset by the impact of a settlement payment received in 2017 associated with a contract dispute; and

an increase in crude oil revenue of \$91.3 million primarily due to the full-year benefit of our condensate splitter at Corpus Christi that began commercial operations in June 2017, as well as more spot shipments on the Longhorn pipeline and Houston distribution system due to the favorable pricing differential between the Permian Basin and Houston, which resulted in more volume at a higher average rate. Overall, the average crude rate per barrel decreased between periods due to significantly higher volumes on our Houston distribution system, which move at a lower rate. We also benefited from higher revenues from new system storage and ancillary services that we provided to our shippers in conjunction with capacity from our storage contracts with Seabrook. Additionally, tender revenue increased as a result of higher volumes and higher crude prices.

Affiliate management fee revenue was \$2.7 million higher than the prior year primarily resulting from management fees received from recently-formed joint ventures.

Operating expenses increased \$71.4 million, resulting from:

an increase in refined products expenses of \$24.4 million primarily due to higher asset integrity spending, additional compensation costs including a pension valuation correction and higher property taxes in part due to a favorable adjustment in 2017, partially offset by more favorable product overages (which reduce operating expenses);

an increase in crude oil expenses of \$45.3 million primarily due to fees we paid to Seabrook for contract storage and ancillary services that we utilized to provide services to our shippers, higher compensation and other costs associated with our condensate splitter that began commercial operations in June 2017, higher environmental remediation accruals, higher losses on asset write-offs and retirements and less favorable product overages; and

an increase in marine storage expenses of \$2.7 million primarily due to higher compensation costs and less favorable product overages, partially offset by lower integrity spending as 2017 included clean-up work related to Hurricane Harvey.

Product margin increased \$100.3 million primarily due to gains recognized in the current year on futures contracts, partially offset by lower volumes from our butane blending activities. See Note 12 – Derivative Financial Instruments in Item 8. Financial Statements and Supplementary Data, as well as Other Items—Commodity Derivative Agreements below, for more information about our futures contracts.

Earnings of non-controlled entities increased \$60.1 million primarily due to higher earnings from BridgeTex mainly attributable to incremental shipments related to new commitments and increased spot shipments in 2018 for recently added pipeline capacity. Earnings from Saddlehorn were higher primarily due to contractual step-ups in committed shipments in September 2017 and again in September 2018. Additional storage and dock capacity contributed to higher earnings from Seabrook, while earnings from Powder Springs and Double Eagle were also higher.

Depreciation, amortization and impairment expense increased \$68.4 million primarily due to a \$49.1 million asset impairment charge recognized in 2018 related to our ammonia pipeline and commencement of depreciation of expansion capital projects recently placed into service.

G&A expense increased \$28.6 million primarily due to higher compensation costs resulting from an increase in employee headcount as a result of the growth of our business and higher bonus and incentive accruals due to company performance, as well as expense related to a pension valuation correction.

Interest expense, net of interest income and interest capitalized, increased \$6.8 million in 2018 primarily due to higher outstanding debt, partially offset by higher interest capitalized and interest income. Our average outstanding debt increased from \$4.3 billion in 2017 to \$4.5 billion in 2018 primarily due to borrowings for expansion capital expenditures. Our weighted-average interest rate of 4.8% in 2018 was comparable to 2017.

Gain on disposition of assets was \$335.3 million favorable. We recognized a \$353.8 million gain on the sale of a portion of our interest in BridgeTex in 2018. In 2017, we recognized an \$18.5 million gain in connection with the sale of an inactive terminal along our refined products pipeline system.

Other expense was \$9.8 million unfavorable in 2018 primarily due to higher pension-related costs in the current period, which include the impact of a pension valuation correction.

Provision for income taxes was \$3.8 million favorable due to the impact of a change in our tax position related to depreciation.

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

	Year Ended		Variance		
	December 31, 2016	December 31, 2017	Favorable (Unfavorable)		
			\$ Change	% Change	
Financial Highlights (\$ in millions, except operating statistics)					
Transportation and terminals revenue:					
Refined products	\$1,002.4	\$1,096.0	\$ 93.6	9	%
Crude oil	407.8	458.5	50.7	12	%
Marine storage	181.7	180.7	(1.0)	(1)	%
Intersegment eliminations	(0.8)	(3.4)	(2.6)	(325)	%
Total transportation and terminals revenue	1,591.1	1,731.8	140.7	9	%
Affiliate management fee revenue	14.7	17.7	3.0	20	%
Operating expenses:					
Refined products	380.4	400.4	(20.0)	(5)	%
Crude oil	88.6	120.9	(32.3)	(36)	%
Marine storage	65.5	65.3	0.2	—	%
Intersegment eliminations	(5.8)	(8.6)	2.8	48	%
Total operating expenses	528.7	578.0	(49.3)	(9)	%
Product margin:					
Product sales revenue	599.6	758.2	158.6	26	%
Cost of product sales	493.3	635.6	(142.3)	(29)	%
Product margin	106.3	122.6	16.3	15	%
Earnings of non-controlled entities	78.7	121.0	42.3	54	%
Operating margin	1,262.1	1,415.1	153.0	12	%
Depreciation, amortization and impairment expense	178.1	196.7	(18.6)	(10)	%
G&A expense	147.2	165.7	(18.5)	(13)	%
Operating profit	936.8	1,052.7	115.9	12	%
Interest expense (net of interest income and interest capitalized)	165.4	193.7	(28.3)	(17)	%
Gain on disposition of assets	(28.1)	(18.5)	(9.6)	(34)	%
Other (income) expense	(6.5)	4.1	(10.6)	n/a	
Income before provision for income taxes	806.0	873.4	67.4	8	%
Provision for income taxes	3.2	3.9	(0.7)	(22)	%
Net income	\$802.8	\$869.5	\$ 66.7	8	%

Operating Statistics

Refined products:

Transportation revenue per barrel shipped	\$1.473	\$1.495
Volume shipped (million barrels):		
Gasoline	275.4	295.5
Distillates	150.2	166.2
Aviation fuel	25.7	26.5
Liquefied petroleum gases	10.4	9.9
Total volume shipped	461.7	498.1
Crude oil:		
Magellan 100%-owned assets:		
Transportation revenue per barrel shipped	\$1.321	\$1.348
Volumes shipped (million barrels)	187.0	196.4
Crude oil terminal average utilization (million barrels per month)	15.0	15.3
Select joint venture pipelines:		

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BridgeTex - volume shipped (million barrels) ^(a)	79.0	98.4
Saddlehorn - volume shipped (million barrels) ^(b)	5.2	19.0
Marine storage:		
Marine terminal average utilization (million barrels per month)	23.8	23.1

(a) These volumes reflect total shipments for the BridgeTex pipeline which was owned 50% by us during 2016 and 2017.

(b) These volumes reflect the total shipments for the Saddlehorn pipeline, which began operations in September 2016 and is owned 40% by us.

Transportation and terminals revenue increased by \$140.7 million, resulting from:

an increase in refined products revenue of \$93.6 million. Shipments increased in 2017 primarily due to stronger demand for gasoline and distillate in the markets we serve and increased volumes from our Little Rock pipeline extension, which commenced commercial operations in July 2016. The average rate per barrel in 2017 was favorably impacted by the mid-year 2016 and 2017 tariff adjustments but was largely offset by additional short-haul movements within South Texas, which ship at a lower rate than our other pipeline segments. Additionally, 2017 benefited from a one-time customer payment associated with a contract dispute settlement and higher storage and other ancillary service fees along our pipeline system due to increased customer activity;

an increase in crude oil revenue of \$50.7 million primarily due to contributions from our condensate splitter at Corpus Christi that began commercial operations in June 2017, higher volumes and higher average rates on our Longhorn pipeline and higher deficiency revenue for volume committed but not moved on our Houston distribution system; and

a decrease in marine storage revenue of \$1.0 million primarily due to lower utilization due to the timing of maintenance work and tanks damaged by Hurricane Harvey that were still under repair. Otherwise, higher storage rates partially offset lower utilization.

Affiliate management fee revenue was \$3.0 million higher than the prior year primarily resulting from management fees received from recently-formed joint ventures.

Operating expenses increased \$49.3 million, resulting from:

an increase in refined products expenses of \$20.0 million primarily due to higher asset integrity spending related to the timing of maintenance work, rental costs for a pipeline segment we began leasing in third quarter 2016 in connection with our Little Rock pipeline and higher compensation costs, partially offset by more favorable product overages (which reduce operating expenses);

an increase in crude oil expenses of \$32.3 million primarily due to higher compensation and other costs associated with our condensate splitter that began commercial operations in June 2017, less favorable product overages and more asset integrity spending during 2017; and

a decrease in marine storage expenses of \$0.2 million as higher environmental remediation expense and clean-up work related to Hurricane Harvey and higher compensation costs were largely offset by favorable product overages.

Product margin increased \$16.3 million primarily due to lower losses recognized in 2017 on futures contracts, partially offset by lower margins on product sales from our butane blending activities. See Other Items—Commodity Derivative Agreements below for more information about our futures contracts.

Earnings of non-controlled entities increased \$42.3 million primarily due to higher earnings from BridgeTex mainly attributable to incremental spot shipments (including spot shipments by us; see Note 5 – Investments in Non-Controlled Entities in Item 8. Financial Statements and Supplementary Data for information about spot shipments that we made on the BridgeTex pipeline), as well as additional shipments from BridgeTex's new Eaglebine origin. Additionally, we received higher earnings from Saddlehorn, which began operating during third quarter 2016.

Depreciation, amortization and impairment expense increased \$18.6 million primarily due to commencement of depreciation of expansion capital projects that had recently been placed into service.

G&A expense increased \$18.5 million primarily due to higher compensation costs resulting from an increase in employee headcount as a result of the growth of our business and higher bonus accruals.

Interest expense, net of interest income and interest capitalized, increased \$28.3 million in 2017 primarily due to higher outstanding debt and lower capitalized interest in 2017, partially offset by slightly lower average rates. Our average outstanding debt increased from \$3.9 billion in 2016 to \$4.3 billion in 2017 primarily due to borrowings for expansion capital expenditures. Our weighted-average interest rate of 4.8% in 2017 was lower than the 4.9% rate incurred in 2016.

Gain on disposition of assets was \$9.6 million unfavorable due to higher gains recognized in 2016. In 2017, we recognized an \$18.5 million gain in connection with the sale of an inactive terminal along our refined products pipeline system. In 2016, we recognized a \$28.1 million gain related to the transfer of our 50% membership interest in Osage Pipe Line Company, LLC.

Other (income) expense was \$10.6 million unfavorable due to higher pension-related costs in 2017, including higher pension settlements, and a less favorable non-cash adjustment in 2017 for the change in the differential between the current spot price and forward price on fair value hedges.

Distributable Cash Flow

Distributable cash flow (“DCF”) and Adjusted EBITDA are non-GAAP measures. See Item 6. Selected Financial Data for a discussion of how management uses these non-GAAP measures. A reconciliation of DCF and Adjusted EBITDA for the years ended December 31, 2016, 2017 and 2018 to net income, which is the nearest comparable GAAP financial measure, is as follows (in millions):

	Year Ended December 31,		
	2016	2017	2018
Net income	\$802.8	\$869.5	\$1,333.9
Interest expense, net	165.4	193.7	200.5
Depreciation, amortization and impairment ⁽¹⁾	178.1	196.6	256.1
Equity-based incentive compensation ⁽²⁾	5.0	6.8	22.8
Loss on sale and retirement of assets	11.2	13.4	16.4
Gain on disposition of assets ⁽³⁾	(28.1)	(18.5)	(351.2)
Commodity-related adjustments:			
Derivative (gains) losses recognized in the period associated with future product transactions ⁽⁴⁾	21.8	37.6	(71.5)
Derivative gains (losses) recognized in previous periods associated with product sales completed in the period ⁽⁴⁾	45.2	(25.5)	(39.6)
Inventory valuation adjustments ⁽⁵⁾	(2.8)	0.4	9.2
Total commodity-related adjustments	64.2	12.5	(101.9)
Distributions received from non-controlled entities in excess of earnings	9.3	25.2	15.6
Other ⁽⁶⁾	5.3	3.7	3.6
Adjusted EBITDA	1,213.2	1,302.9	1,395.8
Interest expense, net, excluding debt issuance cost amortization	(162.2)	(190.4)	(197.3)
Maintenance capital ⁽⁷⁾	(103.5)	(91.1)	(88.7)
DCF	\$947.5	\$1,021.4	\$1,109.8

(1) In 2018, we recognized impairment costs of \$49.1 million related to the ammonia pipeline system, of which \$8.9 million represents cash requirements to decommission the pipeline and is deducted from DCF.

Because we intend to satisfy vesting of unit awards under our equity-based long-term incentive compensation plan with the issuance of limited partner units, expenses related to this plan generally are deemed non-cash and added back for DCF purposes. The amounts above have been reduced by \$14.4 million, \$13.9 million and \$9.3 million, respectively, for cash payments associated with the plan, which are primarily related to tax withholdings.

(2) In 2018, we recognized a \$353.8 million gain in connection with the sale of a portion of our interest in BridgeTex of which \$351.2 has been deducted from the calculation of DCF, as it is not related to our ongoing operations. The (3) remaining \$2.6 million represents a purchase price adjustment related to operations, and as such is included in DCF. See Note 5 – Investments in Non-Controlled Entities in Item 8. Financial Statements and Supplementary Data for further details about this sale.

In 2017, we recognized an \$18.5 million gain in connection with the sale of an inactive terminal along our refined products pipeline, which has been deducted from the calculation of DCF because it is not related to our ongoing operations.

In 2016, we transferred our 50% membership interest in Osage Pipe Line Company, LLC (“Osage”) to an affiliate of HollyFrontier Corporation (“HFC”). In conjunction with this transaction we entered into several commercial agreements with affiliates of HFC, which were recorded as intangible assets and other receivables on our consolidated balance sheets. We recorded a \$28.1 million non-cash gain in relation to this transaction.

(4) Certain derivatives we use as economic hedges have not been designated as hedges for accounting purposes and the mark-to-market changes of these derivatives are recognized currently in net income. We exclude the net impact of these hedges from our determination of DCF until the hedged products are physically sold. In the period in

which these hedged products are physically sold, the net impact of the associated hedges is included in our determination of DCF.

We adjust DCF for lower of cost or net realizable value adjustments related to inventory and firm purchase commitments as well as market valuations of short positions recognized each period as these are non-cash items. In (5) subsequent periods when we physically sell or purchase the related products, we adjust DCF for the valuation adjustments previously recognized.

Other adjustments in 2018 include a \$3.6 million adjustment recorded to partners' capital as required by our (6) adoption of Accounting Standards Update 2014-09, Revenue from Contracts with Customers. The amount represents cash that we had previously received for

deficiency payments but did not yet recognize in net income under the previous revenue recognition standard. Other adjustments in 2016 and 2017 include payments received from HFC in conjunction with the February 2016 Osage exchange transaction. These payments replaced distributions we would have received had the Osage transaction not occurred and are, therefore, included in our calculation of DCF.

Maintenance capital expenditures maintain our existing assets and do not generate incremental DCF (i.e. (7) incremental returns to our unitholders). For this reason, we deduct maintenance capital expenditures to determine DCF.

Liquidity and Capital Resources

Cash Flows and Capital Expenditures

Operating Activities. Net cash provided by operating activities was \$973.3 million, \$1,131.2 million and \$1,353.0 million for the years ended December 31, 2016, 2017 and 2018, respectively. The \$221.8 million increase from 2017 to 2018 was due to higher net income as previously described and changes in our working capital, partially offset by adjustments for non-cash items. The \$157.9 million increase from 2016 to 2017 was due to higher net income as previously described, adjustments to non-cash items and changes in our working capital.

Investing Activities. Net cash used by investing activities for the years ended December 31, 2016, 2017 and 2018 was \$866.6 million, \$593.2 million and \$119.3 million, respectively. During 2018, we sold a portion of our interest in BridgeTex for cash proceeds of \$575.6 million. Also during 2018, we spent \$562.3 million on capital expenditures, which included \$88.7 million for maintenance capital, \$425.0 million for our expansion capital projects and \$48.6 million for undivided joint interest projects for which cash was received from a third party. Additionally, we contributed capital of \$216.4 million in conjunction with our joint venture capital projects, which we account for as investments in non-controlled entities. During 2017, we spent \$572.7 million on capital expenditures, which included \$91.2 million for maintenance capital and \$481.6 million for expansion capital. Also during 2017, we contributed capital of \$134.8 million in conjunction with our joint venture capital projects. During 2016, we spent \$653.5 million on capital expenditures, which included \$103.5 million for maintenance capital and \$550.0 million for expansion capital. Also during 2016, we contributed capital of \$200.0 million in conjunction with our joint venture capital projects.

Financing Activities. Net cash used by financing activities for the years ended December 31, 2016, 2017 and 2018 was \$120.7 million, \$376.7 million and \$1,100.5 million, respectively. During 2018, we paid cash distributions of \$865.4 million to our unitholders and repaid our \$250.0 million of 6.40% notes due 2018. Also, in January 2018, our equity-based long-term incentive plan (“LTIP”) awards that vested December 31, 2017 were settled by issuing 168,913 limited partner units to the LTIP participants, resulting in payments primarily associated with tax withholdings of \$9.3 million. During 2017, we paid cash distributions of \$803.2 million to our unitholders. Additionally, we received net proceeds of \$496.7 million from borrowings under long-term notes, which were used to repay borrowings outstanding under our commercial paper program and for general partnership purposes, including expansion capital. Net commercial paper repayments during 2017 totaled \$50.0 million. Also, in January 2017, our LTIP awards that vested December 31, 2016 were settled by issuing 216,679 limited partner units to the LTIP participants, resulting in payments primarily associated with tax withholdings of \$13.9 million. During 2016, we paid cash distributions of \$739.2 million to our unitholders. Additionally, we received net proceeds of \$1.1 billion from borrowings under long-term notes, which were used in part to repay our \$250.0 million of 5.65% notes due 2016, to repay borrowings outstanding under our commercial paper program and for general partnership purposes, including expansion capital. Net commercial paper repayments during 2016 totaled \$230.0 million. Also, in February 2016, our LTIP awards that vested December 31, 2015 were settled by issuing 350,552 limited partner units to the LTIP participants, resulting in payments of associated tax withholdings of \$14.4 million.

The quarterly distribution amount related to fourth quarter 2018 earnings was \$0.9975 per unit, which was paid in February 2019. If we are able to meet management’s targeted distribution growth of 5% during 2019 and the number of outstanding limited partner units remains at 228.4 million, total cash distributions of approximately \$928 million

will be paid to our unitholders related to 2019 earnings. Management believes we will have sufficient DCF to fund these distributions.

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Capital Requirements

Our business requires continual investment to upgrade or enhance existing operations and to ensure compliance with safety and environmental regulations. Capital spending for our business consists primarily of:

Maintenance capital expenditures. These capital expenditures include costs required to maintain equipment reliability and safety and to address environmental or other regulatory requirements rather than to generate incremental DCF; and

Expansion capital expenditures. These expenditures are undertaken primarily to generate incremental DCF and include costs to acquire additional assets to grow our business and to expand or upgrade our existing facilities, which we refer to as organic growth projects. Organic growth projects include, for example, capital expenditures that increase storage or throughput volumes or develop pipeline connections to new supply sources.

During 2018, our maintenance capital spending was \$88.7 million. For 2019, we expect to spend approximately \$95 million on maintenance capital.

During 2018, we spent nearly \$640 million on organic growth construction projects. Based on the progress of expansion projects already underway, we expect to spend approximately \$1.3 billion for expansion capital during 2019, with an additional \$400 million in 2020 to complete our current projects. See Growth Projects above for additional information.

Liquidity

Cash generated from operations is a key source of liquidity for funding debt service, maintenance capital expenditures and quarterly distributions. Additional liquidity for purposes other than quarterly distributions, such as expansion capital expenditures and debt repayments, is available through borrowings under our commercial paper program and revolving credit facilities, as well as from other borrowings or issuances of debt or limited partner units (see Note 11 – Debt in Item 8. Financial Statements and Supplementary Data of this report for detail of our borrowings and debt outstanding at December 31, 2017 and 2018). If capital markets do not permit us to issue additional debt and equity securities, our business may be adversely affected, and we may not be able to acquire additional assets and businesses, fund organic growth projects or continue paying cash distributions at the current level.

Off-Balance Sheet Arrangements

None.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2018 (in millions):

	Total	< 1 year	1-3 years	4-5 years	> 5 years
Long-term debt obligations ⁽¹⁾	\$4,300.0	\$550.0	\$550.0	\$ —	\$3,200.0
Interest obligations ⁽¹⁾	3,065.0	189.1	324.0	297.2	2,254.7
Operating lease obligations	282.6	33.8	62.5	54.1	132.2
Storage contract commitments ⁽²⁾	14.5	4.9	7.3	1.2	1.1
Pension and postretirement medical obligations ⁽³⁾	123.4	32.9	65.6	17.3	7.6
Purchase commitments:					
Product purchase commitments ⁽⁴⁾	95.0	83.8	11.2	—	—
Utility purchase commitments	13.5	8.2	5.1	0.1	0.1
Derivative instruments ⁽⁵⁾	—	—	—	—	—
Equity-based incentive awards ⁽⁶⁾	49.4	22.1	27.3	—	—
Capital project purchase obligations	180.6	147.4	33.2	—	—
Maintenance obligations	117.6	113.6	4.0	—	—
Other	7.3	4.2	1.5	1.6	—
Total	\$8,248.9	\$1,190.0	\$1,091.7	\$ 371.5	\$5,595.7

At December 31, 2018, we had no borrowings outstanding under our revolving credit facility or commercial paper program. For purposes of this table, we have reflected no assumed borrowings under our revolving credit facility or commercial paper program for any periods presented. We have included interest obligations based on the stated amounts of our fixed-rate obligations.

(2) We have entered into product storage contracts with third parties. The cost of storage services is recognized in cost of product sales on our consolidated statements of income.

(3) Represents the projected benefit obligation of our pension and postretirement medical plans less the fair value of plan assets.

Includes product purchase commitments for which the price provisions are indexed based on the date of delivery.

(4) We have estimated the value of these commitments using the related index price curve as of December 31, 2018.

Also, we have excluded certain product purchase agreements for which there is no specified or minimum quantity.

(5) As of December 31, 2018, we had entered into exchange-traded futures contracts representing 4.1 million barrels of petroleum products that we expect to sell in the future and 0.9 million barrels of butane we expect to purchase in the future. At December 31, 2018, we had recorded a net asset of \$55.0 million and held margin deposits of \$37.3 million. We have excluded from this table the future net cash outflows, if any, under these futures contracts and the amounts of future margin deposit requirements because those amounts are uncertain.

Settlements of our LTIP awards will differ from these reported amounts primarily due to differences between

(6) actual and current estimates of payout percentages and completion of the remaining portion of the requisite service periods.

Environmental

Our operations are subject to federal, state and local environmental laws and regulations. We have accrued liabilities for estimated costs at our facilities and properties. We record liabilities when environmental costs are probable and can be reasonably estimated. The determination of amounts recorded for environmental liabilities involves significant judgments and assumptions by management. Due to the inherent uncertainties involved in determining environmental liabilities, it is reasonably possible that the actual amounts required to extinguish these liabilities could be materially different from those we have recognized.

Other Items

Pipeline Tariff Increase. The Federal Energy Regulatory Commission (“FERC”) regulates the rates charged on interstate common carrier pipeline operations primarily through an indexing methodology, which establishes the maximum amount by which index-based tariffs can be adjusted each year. Approximately 40% of our refined products tariffs are subject to this indexing methodology. The remaining 60% of our refined products tariffs are either subject to regulations by the states in which we operate or are approved for market-based rates by the FERC,

and in both cases these rates can be adjusted at our discretion based on market factors. The current FERC-approved indexing method is the annual change in the producer price index for finished goods (“PPI-FG”) plus 1.23%. Based on the preliminary estimates for this indexing methodology in 2018, we expect to increase virtually all of our refined products pipeline rates by approximately 4.3% on July 1, 2019. Most of the tariffs on our crude oil pipelines are established at negotiated rates that generally provide for annual adjustments in line with changes in the FERC index, subject to certain modifications. We also expect to increase the rates of our crude oil pipelines by approximately 4% on average in July 2019.

Sale of Interest in BridgeTex. In September 2018, we sold a 20% interest in BridgeTex to an affiliate of OMERS Infrastructure Management Inc., which reduced our ongoing ownership in BridgeTex to a 30% interest. We received \$575.6 million in cash from the sale and recorded a gain of \$353.8 million on our consolidated statements of income. We continue to serve as the operator of BridgeTex.

Crude Oil Pipeline Contract Renewals. Due to increased competition, recent contract renewals have resulted in lower average crude oil tariff rates for term commitments. For example, the initial term of our contracts for the Longhorn pipeline expired in September 2018, and some shippers elected to extend their contracts under current terms for an additional two years, while others executed new contracts with lower incentive tariff rates and terms up to 10 years, resulting in an average contract term of five years and a lower average tariff rate. Although we continue to believe that demand for capacity on Longhorn and our other crude oil pipelines remains strong, the pricing environment for term commitments on crude oil pipelines is very competitive, and we continue to assume the average tariff rates agreed to for term commitments on our crude oil pipelines, including the crude oil pipelines of our joint ventures, will be lower upon future renewals.

Commodity Derivative Agreements. Certain of the business activities in which we engage result in our owning various commodities, which exposes us to commodity price risk. We use forward physical commodity contracts and exchange-based futures contracts to help manage this commodity price risk. We use forward physical contracts to purchase butane and sell refined products. We account for these forward physical contracts as normal purchase and sale contracts, using traditional accrual accounting. We use futures contracts to hedge against changes in prices of petroleum products that we expect to sell or purchase in future periods. We use and account for those futures contracts that qualify for hedge accounting treatment as either cash flow or fair value hedges, and we use and account for those futures contracts that do not qualify for hedge accounting treatment as economic hedges.

As of December 31, 2018, our open derivative contracts and the impact of the derivatives we settled during the period were comprised of futures contracts used to hedge sales and purchases of refined products, crude oil and butane related to our tender deductions, product overages, butane blending and fractionation activities. These contracts were accounted for as economic hedges, with the change in fair value of contracts that hedge future sales recorded to product sales revenue, and the change in fair value of contracts that hedge future purchases recorded to cost of product sales.

For further information regarding the quantities of refined products and crude oil hedged at December 31, 2018 and the fair value of open hedge contracts at that date, please see Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

The following tables provide a summary of the impacts of the mark-to-market gains and losses associated with these futures contracts on our results of operations for the respective periods presented (in millions):

	Year Ended December 31, 2016				Net Impact on Results of Operations
	Product Sales Revenue	Cost of Product Sales	Operating Expense	Other Income	
Gains (losses) recorded on open futures contracts during the period	\$(30.2)	\$ 6.1	\$ (3.6)	\$ 5.2	\$ (22.5)
Gains (losses) recognized on settled futures contracts during the period	(8.4)	4.9	(1.4)	—	(4.9)
Net impact of futures contracts	\$(38.6)	\$ 11.0	\$ (5.0)	\$ 5.2	\$ (27.4)
	Year Ended December 31, 2017				Net Impact on Results of Operations
	Product Sales Revenue	Cost of Product Sales	Operating Expense	Other Income	
Gains (losses) recorded on open futures contracts during the period	\$(38.6)	\$ 12.8	\$ —	\$ 2.4	\$ (23.4)
Gains (losses) recognized on settled futures contracts during the period	(17.7)	12.8	3.0	—	(1.9)
Net impact of futures contracts	\$(56.3)	\$ 25.6	\$ 3.0	\$ 2.4	\$ (25.3)
	Year Ended December 31, 2018				Net Impact on Results of Operations
	Product Sales Revenue	Cost of Product Sales	Operating Expense	Other Income	
Gains (losses) recorded on open futures contracts during the period	\$62.3	\$(7.3)	\$ —	\$ —	—\$ 55.0
Gains (losses) recognized on settled futures contracts during the period	22.7	(8.6)	—	—	14.1
Net impact of futures contracts	\$85.0	\$(15.9)	\$ —	\$ —	—\$ 69.1

Related Party Transactions. See Note 10 – Related Party Transactions in Item 8. Financial Statements and Supplementary Data of this report for detail of our related party transactions.

Critical Accounting Estimates

Our management has discussed the development and selection of the following critical accounting estimates with the audit committee of our general partner's board of directors, which has reviewed and approved these disclosures.

Pension Obligations

We sponsor two union pension plans covering union employees and a pension plan for non-union employees. Various estimates and assumptions directly affect net periodic benefit expense and obligations for these plans. These estimates and assumptions include the expected long-term rates of return on plan assets, discount rates and the expected rate of compensation increase. Management reviews these assumptions annually and makes adjustments as necessary.

The following table presents the estimated increase (decrease) in net periodic benefit expense and obligations that would result from a 1% change in the specified assumption (in thousands):

	Benefit Expense		Benefit Obligation	
	1% Increase	1% Decrease	1% Increase	1% Decrease
Pension benefits:				
Discount rate	\$(3,812)	\$4,347	\$(29,570)	\$35,111
Expected long-term rate of return on plan assets	\$(2,064)	\$2,064	\$—	\$—
Rate of compensation increase	\$4,875	\$(5,047)	\$21,891	\$(22,799)

The following table sets forth the increase (decrease) in our pension funding based on our current funding policy assuming a 1% change in the specified criterion (in thousands):

	1% Increase	1% Decrease
	Projected return on assets	\$(2,189)
Rate of compensation increase	\$2,079	\$(2,002)

The discount rate directly affects the measurement of the benefit obligations of our pension benefit plans. The objective of the discount rate is to determine the amount, if invested at the December 31 measurement date in a portfolio of high-quality fixed income securities, that would provide the necessary cash flows to make benefit payments when due. Decreases in the discount rate increase the obligation and generally increase the related expense, while increases in the discount rate have the opposite effect. Changes in general economic and market conditions that affect interest rates on long-term high-quality fixed income securities as well as the duration of our plans' liabilities affect our estimate of the discount rate.

We estimate the long-term expected rate of return on plan assets using expectations of capital market results, which includes an analysis of historical results as well as forward-looking projections. We base these capital market expectations on a long-term period and on our investment strategy and asset allocation. We develop our estimates using input from several external sources, including consultation with our third-party independent investment consultant. We develop the forward-looking capital market projections using a consensus of expectations by economists for inflation and dividend yield, along with expected changes in risk premiums. Because our determined rate is an estimate of future results, it could be significantly different from actual results. The expected rates of return on plan assets are long-term in nature; therefore, short-term market performance does not significantly affect our estimated long-term expected rate of return.

The expected rate of compensation increase represents average long-term salary increases. An increase in this rate causes the pension obligation and expense to increase.

Impairment of Long-Lived Assets and Goodwill

Impairment of Long-Lived Assets. Long-lived assets, including fixed assets, investments in non-controlled entities and other intangibles are reviewed for impairment whenever events or changes in circumstances indicate that the carrying value may not be recoverable. Such indicators include, among others, the nature of the asset, the projected future economic benefit of the asset, changes in regulatory and political environments and historical and future cash flow and profitability measurements. If the carrying value of an asset exceeds the future undiscounted cash flows expected from the asset, we recognize an impairment charge for the excess of carrying value of the asset over its estimated fair value.

During 2018, we made the decision to discontinue commercial operations of our ammonia pipeline beginning in late 2019 due to the system's low profitability and challenging economic outlook. As a result, we recognized an impairment charge of \$49.1 million.

Goodwill. The goodwill relating to each of our reporting units is tested for impairment annually as well as when an event or change in circumstances indicates an impairment may have occurred. Under GAAP, we have the option to first assess qualitative factors to determine whether it is more likely than not that the fair value of one of our reporting units is greater than its carrying amount. If, after assessing the totality of events or circumstances, we determine it is more likely than not that the fair value of a reporting unit is greater than its carrying amount, we do not perform any further testing. However, if we conclude otherwise, we perform the first step of a two-step impairment test by calculating the fair value of the reporting unit and comparing the fair value with the carrying amount of the reporting unit. If the fair value of the reporting unit is less than its carrying value, an impairment loss is recorded to the extent that the implied fair value of the goodwill of the reporting unit is less than its carrying value.

For purposes of performing the impairment test for goodwill, our reporting units are our reportable segments. In 2016, we elected to perform the qualitative assessment described above for purposes of our annual goodwill impairment test. Based on this assessment, we concluded that it was more likely than not that the fair value of each of our reporting units was greater than its carrying amount. In 2017 and 2018, we elected to complete the quantitative goodwill impairment test and began with step one of the test as required by Accounting Standards Codification (“ASC”) 350-20-35-4. Based on these assessments, we calculated that the fair value of each of our reporting units was greater than its carrying amount.

Determination as to whether and how much goodwill or long-lived assets are impaired involves management estimates on highly uncertain matters such as future commodity prices, the effects of inflation and technology improvements on operating expenses and the outlook for national or regional market supply and demand conditions. We base the impairment reviews and calculations used in our impairment tests on assumptions that are consistent with our business plans and long-term investment decisions. See Note 7—Property, Plant and Equipment in Item 8. Financial Statements and Supplementary Data for additional information regarding impairments of goodwill and long-lived assets.

Environmental Liabilities

We estimate the liabilities associated with environmental expenditures based on site-specific project plans for remediation, taking into account prior remediation experience. Remediation project managers evaluate each known case of environmental liability to determine what associated costs can be reasonably estimated and to ensure compliance with all applicable federal and state requirements. The accounting estimate relative to environmental remediation costs is a critical accounting estimate for each of our operating segments because: (i) estimated expenditures are subject to cost fluctuations and could change materially, (ii) as remediation work is performed and additional information relative to each specific site becomes known, cost estimates for those sites could change materially, (iii) unanticipated third-party liabilities may arise, (iv) it is difficult to determine the amounts, if any, of penalties that may be levied by governmental agencies with regard to certain environmental events and (v) when changes in federal, state and local environmental regulations occur, these changes could significantly impact the amount of our environmental liability accruals.

A defined process for project review is integrated into our system integrity plan. Each year our remediation project managers meet to evaluate, in detail, our known environmental sites. The purpose of the annual project review is to assess all aspects of each project, evaluating what actions will be required to achieve regulatory compliance and estimating the costs and timing to execute the regulatory phases that can be reasonably estimated. During the site-specific evaluations, we utilize all known information in conjunction with professional judgment and experience to determine the appropriate approach for remediation and to assess liabilities. The process to achieve regulatory compliance consists of site investigation/delineation, site remediation and long-term monitoring. Each of these phases can, and often does, include unknown variables that complicate the task of evaluating the estimated costs to completion. At each accounting period-end, we re-evaluate our environmental estimates taking into account any new

incidents that have occurred, any changes in the remediation for existing sites, including work to

date, additional findings or changes in federal or state regulations and changes in cost estimates. Changes in our environmental liabilities since December 31, 2016 were as follows (in millions):

Balance 2017			Balance 2018			Balance
12/31/16	Accruals	Expenditures	12/31/17	Accruals	Expenditures	12/31/18
\$24.0	\$12.8	\$(17.5)	\$19.3	\$17.2	\$(16.0)	\$20.5

During 2018, we accrued \$17.2 million of environmental liabilities. Of this amount, \$11.0 million related to product releases that occurred during 2018, and the remaining accrual adjustments of \$6.2 million related to historical releases. At December 31, 2018, we had recognized \$4.1 million of receivables from insurance carriers associated with environmental claims.

During 2017, we accrued \$12.8 million of environmental liabilities. Of this amount, \$9.4 million related to product releases that occurred during 2017, and the remaining accrual adjustments of \$3.4 million related to historical releases. At December 31, 2017, we had recognized \$7.2 million of receivables from insurance carriers associated with environmental claims.

We based our period-end environmental liabilities on estimates that are subject to change, and any changes to these estimates would affect our results of operations and financial position. Any increase in our environmental liabilities would decrease our operating profit and net income by the same amount, which would negatively impact basic and diluted net income per limited partner unit.

New Accounting Pronouncements

See Note 2 – Summary of Significant Accounting Policies in Item 8. Financial Statements and Supplementary Data of this report for a summary of new accounting pronouncements.

Forward-Looking Statements

Certain matters discussed in this Annual Report on Form 10-K include forward-looking statements within the meaning of the federal securities laws that discuss our expected future results based on current and pending business operations. Forward-looking statements can be identified by words such as “anticipates,” “believes,” “continue,” “could,” “estimates,” “expects,” “forecasts,” “goal,” “guidance,” “intends,” “may,” “might,” “plans,” “potential,” “projected,” “scheduled” and other similar expressions. Although we believe our forward-looking statements are based on reasonable assumptions, statements made regarding future results are not guarantees of future performance and are subject to numerous assumptions, uncertainties and risks that are difficult to predict. Therefore, actual outcomes and results may be materially different from the results stated or implied in such forward-looking statements included in this report.

The following are among the important factors that could cause future results to differ materially from any expected, projected, forecasted, estimated or budgeted amounts, events or circumstances we have discussed in this report:

- overall demand for refined products, crude oil and liquefied petroleum gases in the U.S.;
- price fluctuations for refined products, crude oil and liquefied petroleum gases and expectations about future prices for these products;
- changes in the production of crude oil in the basins served by our pipelines;
- changes in general economic conditions, interest rates and price levels;
- changes in the financial condition of our customers, vendors, derivatives counterparties, lenders or joint venture co-owners;
- our ability to secure financing in the credit and capital markets in amounts and on terms that will allow us to execute our growth strategy, refinance our existing obligations when due and maintain adequate liquidity;
- development of alternative energy sources, including but not limited to natural gas, solar power, wind power, electric and battery-powered engines and geothermal energy, increased use of biofuels such as ethanol and biodiesel, increased conservation or fuel efficiency, increased use of electric vehicles, as well as regulatory developments or other trends that could affect demand for our services;
- population decreases in the markets served by our refined products pipeline system and changes in consumer preferences, driving patterns or rates of automobile ownership;
- changes in the throughput or interruption in service of refined products or crude oil pipelines owned and operated by third parties and connected to our assets;
- changes in demand for storage in our refined products, crude oil or marine terminals;
- changes in supply and demand patterns for our facilities due to geopolitical events, the activities of the Organization of the Petroleum Exporting Countries, changes in U.S. trade policies or in laws governing the importing and exporting of petroleum products, technological developments or other factors;
- our ability to manage interest rate and commodity price exposures;
- changes in our tariff rates or other terms of service implemented by the FERC or state regulatory agencies;
- shut-downs or cutbacks at refineries, oil wells, petrochemical plants or other customers or businesses that use or supply our services;
- the effect of weather patterns and other natural phenomena, including climate change, on our operations and demand for our services;
- an increase in the competition our operations encounter;
- the occurrence of natural disasters, terrorism, sabotage, protests or activism, operational hazards, equipment failures, system failures or unforeseen interruptions;
- our ability to obtain adequate levels of insurance at a reasonable cost, and the potential for losses to exceed the insurance coverage we do obtain;
- the treatment of us as a corporation for federal or state income tax purposes or if we become subject to significant forms of other taxation or more aggressive enforcement or increased assessments under existing forms of taxation;
-

our ability to identify expansion projects with acceptable expected returns or to complete identified expansion projects on time and at projected costs;

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our ability to make and integrate accretive acquisitions and joint ventures and successfully execute our business strategy;

- uncertainty of estimates, including accruals and costs of environmental remediation;
- our ability to cooperate with and rely on our joint venture co-owners;
- actions by rating agencies concerning our credit ratings;
- our ability to timely obtain and maintain all necessary approvals, consents and permits required to operate our existing assets and to construct, acquire and operate any new or modified assets;
- our ability to promptly obtain all necessary services, materials, labor, supplies and rights-of-way required for construction of our growth projects, and to complete construction without significant delays, disputes or cost overruns;
- risks inherent in the use and security of information systems in our business and implementation of new software and hardware;
 - changes in laws and regulations or the interpretations of such laws that govern our butane blending activities, including the potential applicability of the Carmack Amendment, which broadly covers claims for damage or loss incurred to goods transported by a carrier in interstate commerce, to such activities, or changes regarding product quality specifications or renewable fuel obligations that impact our ability to produce gasoline volumes through our butane blending activities or that require significant capital outlays for compliance;
- changes in laws and regulations to which we or our customers are or could become subject, including tax withholding requirements, safety, security, employment, hydraulic fracturing, derivatives transactions, trade and environmental laws and regulations, including laws and regulations designed to address climate change;
- the cost and effects of legal and administrative claims and proceedings against us, our subsidiaries or our joint ventures;
- the amount of our indebtedness, which could make us vulnerable to general adverse economic and industry conditions, limit our ability to borrow additional funds, place us at competitive disadvantages compared to our competitors that have less debt or have other adverse consequences;
- the effect of changes in accounting policies;
- the potential that our internal controls may not be adequate, weaknesses may be discovered or remediation of any identified weaknesses may not be successful;
- the ability and intent of our customers, vendors, lenders, joint venture co-owners or other third parties to perform on their contractual obligations to us;
- petroleum product supply disruptions;
- global and domestic repercussions from terrorist activities, including cyber attacks, and the government's response thereto; and
- other factors and uncertainties inherent in the transportation, storage and distribution of petroleum products and the operation, acquisition and construction of assets related to such activities.

This list of important factors is not exclusive. We undertake no obligation to publicly update or revise any forward-looking statement, whether as a result of new information, future events, changes in assumptions or otherwise.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We may be exposed to market risk through changes in commodity prices and interest rates and have established policies to monitor and control these market risks. We use derivative agreements to help manage our exposure to commodity price and interest rate risks.

Commodity Price Risk

Our commodity price risk primarily arises from our butane blending and fractionation activities, and from managing product overages associated with our refined products and crude oil pipelines. We use derivatives such as forward physical contracts and exchange-traded futures contracts to help us manage commodity price risk.

Forward physical contracts that qualify for and are elected as normal purchases and sales are accounted for using traditional accrual accounting. As of December 31, 2018, we had commitments under forward purchase and sale contracts as follows (in millions):

	Total	< 1 Year	1 – 3 Years
Forward purchase contracts – notional value	\$95.0	\$83.8	\$11.2
Forward purchase contracts – barrels	2.5	2.2	0.3
Forward sales contracts – notional value	\$40.3	\$40.3	\$—
Forward sales contracts – barrels	0.6	0.6	—

We also use exchange-traded futures contracts to hedge against changes in the price of petroleum products we expect to sell or purchase. Virtually all of our open contracts did not qualify for hedge accounting treatment under ASC 815, Derivatives and Hedging, and we accounted for these contracts as economic hedges, with changes in fair value recognized currently in earnings. The fair value of these open futures contracts, representing 4.1 million barrels of petroleum products we expect to sell and 0.9 million barrels of butane we expect to purchase, was a net liability of \$54.5 million. With respect to these contracts, a \$10.00 per barrel increase (decrease) in the prices of petroleum products we expect to sell would result in a \$41.0 million decrease (increase) in our operating profit, while a \$10.00 per barrel increase (decrease) in the price of butane we expect to purchase would result in \$9.0 million increase (decrease) in our operating profit. These increases or decreases in operating profit would be substantially offset by higher or lower product sales revenue or cost of product sales when the physical sale or purchase of those products occurs. These contracts may be for the purchase or sale of products in markets different from those in which we are attempting to hedge our exposure, and the related hedges may not eliminate all price risks.

Interest Rate Risk

Our use of variable rate debt and any future issuances of fixed rate debt expose us to interest rate risk.

As of December 31, 2018, we had \$250.0 million of treasury lock agreements to hedge against the risk of variability of future interest payments on a portion of debt we anticipated issuing in the future. In January 2019, we terminated and settled \$150.0 million of these agreements in conjunction with our senior note issuance. The fair value of the remaining \$100.0 million of treasury lock agreements was an asset of \$0.2 million at December 31, 2018. We account for these agreements as cash flow hedges. A 0.125% decrease in interest rates would result in a decrease in the fair value of this asset of approximately \$2.4 million. A 0.125% increase in interest rates would result in an increase of the fair value of this asset of approximately \$2.4 million.

Item 8. Financial Statements and Supplementary Data

Management's Annual Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934, as amended. Our 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.

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.

Management assessed the effectiveness of its internal control over financial reporting as of December 31, 2018. In making this assessment, it used the criteria set forth in 2013 by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control—Integrated Framework. As a result of this assessment management has concluded that, as of December 31, 2018, its internal control over financial reporting is effective based on those criteria.

Ernst & Young LLP, the independent registered public accounting firm that audited our consolidated financial statements included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of our internal control over financial reporting as of December 31, 2018. The report, which expresses an unqualified opinion on the effectiveness of our internal control over financial reporting as of December 31, 2018, is included herein under the heading "Report of Independent Registered Public Accounting Firm" relative to internal control over financial reporting.

By: /S/ MICHAEL N. MEARS

Chairman of the Board, President, Chief Executive Officer and Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.

By: /S/ AARON L. MILFORD

Senior Vice President and Chief Financial Officer of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.

Report of Independent Registered Public Accounting Firm

To the Limited Partners of Magellan Midstream Partners, L.P. and the Board of Directors of Magellan GP, LLC,
General Partner of Magellan Midstream Partners, L.P.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Magellan Midstream Partners, L.P. (the Partnership) as of December 31, 2018 and 2017, the related consolidated statements of income, comprehensive income, partners' capital and cash flows for each of the three years in the period ended December 31, 2018, 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, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, 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, 2018, 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 February 15, 2019 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 1999.
Tulsa, Oklahoma
February 15, 2019

Report of Independent Registered Public Accounting Firm

To the Limited Partners of Magellan Midstream Partners, L.P. and the Board of Directors of Magellan GP, LLC,
General Partner of Magellan Midstream Partners, L.P.

Opinion on Internal Control over Financial Reporting

We have audited Magellan Midstream Partners, L.P.'s internal control over financial reporting as of December 31, 2018, 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, Magellan Midstream Partners, L.P. (the Partnership) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on the COSO criteria.

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, 2018 and 2017, the related consolidated statements of income, comprehensive income, partners' capital and cash flows for each of the three years in the period ended December 31, 2018, and the related notes and our report dated February 15, 2019 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 Annual Report on 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

An entity'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. An entity'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 entity; (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 entity are being made only in accordance with authorizations of management and directors of the entity; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the entity'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

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inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 15, 2019

MAGELLAN MIDSTREAM PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF INCOME
(In thousands, except per unit amounts)

	Year Ended December 31,		
	2016	2017	2018
Transportation and terminals revenue	\$1,591,119	\$1,731,775	\$1,878,988
Product sales revenue	599,602	758,206	927,220
Affiliate management fee revenue	14,689	17,680	20,365
Total revenue	2,205,410	2,507,661	2,826,573
Costs and expenses:			
Operating	528,672	577,978	649,436
Cost of product sales	493,338	635,617	704,313
Depreciation, amortization and impairment	178,142	196,630	265,077
General and administrative	147,165	165,717	194,283
Total costs and expenses	1,347,317	1,575,942	1,813,109
Earnings of non-controlled entities	78,696	120,994	181,117
Operating profit	936,789	1,052,713	1,194,581
Interest expense	194,187	210,698	220,979
Interest capitalized	(27,375)	(15,565)	(17,455)
Interest income	(1,402)	(1,415)	(3,010)
Gain on disposition of assets	(28,144)	(18,505)	(353,797)
Other (income) expense	(6,466)	4,139	13,868
Income before provision for income taxes	805,989	873,361	1,333,996
Provision for income taxes	3,218	3,830	71
Net income	\$802,771	\$869,531	\$1,333,925
Basic net income per limited partner unit	\$3.52	\$3.81	\$5.84
Diluted net income per limited partner unit	\$3.52	\$3.81	\$5.84
Weighted average number of limited partner units outstanding used for basic net income per unit calculation	227,926	228,176	228,377
Weighted average number of limited partner units outstanding used for diluted net income per unit calculation	228,057	228,338	228,573

See notes to consolidated financial statements.

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MAGELLAN MIDSTREAM PARTNERS, L.P.
 CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
 (In thousands)

	Year Ended December 31,		
	2016	2017	2018
Net income	\$802,771	\$869,531	\$1,333,925
Other comprehensive income (loss):			
Derivative activity:			
Net gain (loss) on cash flow hedges	(6,699)	(1,937)	4,317
Reclassification of net loss on cash flow hedges to income	2,049	2,958	2,958
Changes in employee benefit plan assets and benefit obligations recognized in other comprehensive income:			
Net actuarial loss	(2,452)	(46,008)	(2,323)
Amortization of prior service credit	(3,516)	(181)	(181)
Amortization of actuarial loss	5,525	6,371	10,352
Settlement cost	202	2,460	1,964
Total other comprehensive income (loss)	(4,891)	(36,337)	17,087
Comprehensive income	\$797,880	\$833,194	\$1,351,012

See notes to consolidated financial statements.

MAGELLAN MIDSTREAM PARTNERS, L.P.
CONSOLIDATED BALANCE SHEETS
(In thousands)

	December 31,	
	2017	2018
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 160,840	\$ 218,283
Trade accounts receivable	138,779	104,164
Other accounts receivable	14,561	25,007
Inventory	182,345	185,735
Energy commodity derivatives contracts, net	—	55,011
Energy commodity derivatives deposits	36,690	—
Other current assets	63,396	58,143
Total current assets	596,611	646,343
Property, plant and equipment	7,235,468	7,628,592
Less: accumulated depreciation	1,682,633	1,830,411
Net property, plant and equipment	5,552,835	5,798,181
Investments in non-controlled entities	1,082,511	1,076,306
Long-term receivables	27,676	20,844
Goodwill	53,260	53,260
Other intangibles (less accumulated amortization of \$1,389 and \$2,979 at December 31, 2017 and 2018, respectively)	52,764	51,174
Restricted cash	15,228	90,978
Other noncurrent assets	13,490	10,451
Total assets	\$ 7,394,375	\$ 7,747,537
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	\$ 104,852	\$ 138,735
Accrued payroll and benefits	56,261	70,276
Accrued interest payable	70,657	63,258
Accrued taxes other than income	51,343	53,093
Environmental liabilities	6,235	9,153
Deferred revenue	117,795	121,085
Accrued product liabilities	96,159	75,482
Energy commodity derivatives contracts, net	25,694	—
Energy commodity derivatives deposits	—	37,328
Current portion of long-term debt, net	250,974	59,489
Other current liabilities	56,540	48,657
Total current liabilities	836,510	676,556
Long-term debt, net	4,273,518	4,211,380
Long-term pension and benefits	111,305	122,580
Other noncurrent liabilities	30,350	82,240
Environmental liabilities	13,039	11,347
Commitments and contingencies		
Partners' capital:	2,267,231	2,763,925

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Limited partner unitholders (228,025 units and 228,195 units outstanding at December 31, 2017 and 2018, respectively)

Accumulated other comprehensive loss	(137,578)	(120,491)
Total partners' capital	2,129,653	2,643,434
Total liabilities and partners' capital	\$7,394,375	\$7,747,537

See notes to consolidated financial statements.

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MAGELLAN MIDSTREAM PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31,		
	2016	2017	2018
Operating Activities:			
Net income	\$802,771	\$869,531	\$1,333,925
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization and impairment expense	178,142	196,630	265,077
Gain on sale and retirement of assets	(16,954)	(5,135)	(328,055)
Earnings of non-controlled entities	(78,696)	(120,994)	(181,117)
Distributions from operations of non-controlled entities	87,987	146,211	196,686
Equity-based incentive compensation expense	19,358	20,641	32,053
Settlement cost, amortization of prior service credit and actuarial loss	2,211	8,650	12,135
Changes in components of operating assets and liabilities (Note 4)	(21,515)	15,695	22,246
Net cash provided by operating activities	973,304	1,131,229	1,352,950
Investing Activities:			
Additions to property, plant and equipment, net ⁽¹⁾	(674,159)	(558,669)	(552,257)
Proceeds from sale and disposition of assets	7,552	44,392	576,568
Investments in non-controlled entities	(200,023)	(134,828)	(216,424)
Distributions from returns of investments in non-controlled entities	—	55,931	1,786
Deposits received from undivided joint interest third party	—	—	71,071
Net cash used by investing activities	(866,630)	(593,174)	(119,256)
Financing Activities:			
Distributions paid	(739,157)	(803,216)	(865,431)
Net commercial paper repayments	(229,975)	(49,986)	—
Borrowings under long-term notes	1,142,997	496,705	—
Payments on notes	(250,000)	—	(250,000)
Debt placement costs	(10,906)	(6,316)	(404)
Net receipt (payment) on financial derivatives	(19,287)	—	24,619
Payments associated with settlement of equity-based incentive compensation	(14,376)	(13,875)	(9,285)
Net cash used by financing activities	(120,704)	(376,688)	(1,100,501)
Change in cash, cash equivalents and restricted cash	(14,030)	161,367	133,193
Cash, cash equivalents and restricted cash at beginning of period	28,731	14,701	176,068
Cash, cash equivalents and restricted cash at end of period	\$14,701	\$176,068	\$309,261
Supplemental non-cash investing and financing activities:			
Contribution of property, plant and equipment to a non-controlled entity	\$—	\$97,638	\$—
Issuance of limited partner units in settlement of equity-based incentive plan awards	\$7,289	\$1,669	\$120
⁽¹⁾ Additions to property, plant and equipment	\$(653,528)	\$(572,744)	\$(562,296)
Changes in accounts payable and other current liabilities related to capital expenditures	(20,631)	14,075	10,039
Additions to property, plant and equipment, net	\$(674,159)	\$(558,669)	\$(552,257)

See notes to consolidated financial statements.

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MAGELLAN MIDSTREAM PARTNERS, L.P.
CONSOLIDATED STATEMENT OF PARTNERS' CAPITAL
(In thousands)

	Limited Partners	Accumulated Other Comprehensive Loss	Total Partners' Capital
Balance, January 1, 2016	\$2,118,086	\$ (96,350)	\$2,021,736
Comprehensive income:			
Net income	802,771	—	802,771
Total other comprehensive loss	—	(4,891)	(4,891)
Total comprehensive income (loss)	802,771	(4,891)	797,880
Distributions	(739,157)	—	(739,157)
Equity-based incentive compensation expense	19,358	—	19,358
Issuance of limited partner units in settlement of equity-based incentive plan awards	7,289	—	7,289
Payments associated with settlement of equity-based incentive compensation	(14,376)	—	(14,376)
Other	(625)	—	(625)
Balance, December 31, 2016	2,193,346	(101,241)	2,092,105
Comprehensive income:			
Net income	869,531	—	869,531
Total other comprehensive loss	—	(36,337)	(36,337)
Total comprehensive income (loss)	869,531	(36,337)	833,194
Distributions	(803,216)	—	(803,216)
Equity-based incentive compensation expense	20,641	—	20,641
Issuance of limited partner units in settlement of equity-based incentive plan awards	1,669	—	1,669
Payments associated with settlement of equity-based incentive compensation	(13,875)	—	(13,875)
Other	(865)	—	(865)
Balance, December 31, 2017	2,267,231	(137,578)	2,129,653
Comprehensive income:			
Net income	1,333,925	—	1,333,925
Total other comprehensive income	—	17,087	17,087
Total comprehensive income	1,333,925	17,087	1,351,012
Distributions	(865,431)	—	(865,431)
Equity-based incentive compensation expense	32,053	—	32,053
Issuance of limited partner units in settlement of equity-based incentive plan awards	120	—	120
Payments associated with settlement of equity-based incentive compensation	(9,285)	—	(9,285)
ASC 606 cumulative effect	5,975	—	5,975
Other	(663)	—	(663)
Balance, December 31, 2018	\$2,763,925	\$ (120,491)	\$2,643,434

See notes to consolidated financial statements.

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MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Description of Business

Organization

Unless indicated otherwise, the terms “our,” “we,” “us” and similar language refer to Magellan Midstream Partners, L.P. together with its subsidiaries. Magellan Midstream Partners, L.P. is a Delaware limited partnership and its limited partner units trade on the New York Stock Exchange under the ticker symbol “MMP.” Magellan GP, LLC, a wholly owned Delaware limited liability company, serves as its general partner.

Description of Business

We are principally engaged in the transportation, storage and distribution of refined petroleum products and crude oil. As of December 31, 2018, our asset portfolio consisted of:

our refined products segment, comprised of our approximately 9,700-mile refined products pipeline system with 53 terminals as well as 25 independent terminals not connected to our pipeline system and our 1,100-mile ammonia pipeline system;

our crude oil segment, comprised of approximately 2,200 miles of crude oil pipelines, our condensate splitter and 33 million barrels of aggregate storage capacity, of which 21 million barrels are used for contract storage. Approximately 1,000 miles of these pipelines and 28 million barrels of this storage capacity (including 19 million barrels used for contract storage) are wholly-owned, and the remainder is owned through joint ventures; and

our marine storage segment, consisting of six marine terminals located along coastal waterways with an aggregate storage capacity of approximately 27 million barrels. Five of these terminals and approximately 25 million barrels of this storage capacity are wholly-owned, and the remainder is owned through joint ventures.

Description of Products

Terminology common in our industry includes the following terms, which describe products that we transport, store and distribute through our petroleum pipelines and terminals:

refined products are the output from refineries and are primarily used as fuels by consumers. Refined products include gasoline, diesel fuel, aviation fuel, kerosene and heating oil. Collectively, diesel fuel, kerosene and heating oil are referred to as distillate;

- liquefied petroleum gases, or LPGs, are produced as by-products of the crude oil refining process and in connection with natural gas production. LPGs include butane and propane;

blendstocks are blended with refined products to change or enhance their characteristics such as increasing a gasoline's octane or oxygen content. Blendstocks include alkylates, oxygenates and natural gasoline;

heavy oils and feedstocks are used as burner fuels or feedstocks for further processing by refineries and petrochemical facilities. Heavy oils and feedstocks include No. 6 fuel oil and vacuum gas oil;

crude oil, which includes condensate, is used as feedstock by refineries, splitters and petrochemical facilities; and

MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

biofuels, such as ethanol and biodiesel, are typically blended with other refined products as required by government mandates.

We use the term petroleum products to describe any, or a combination, of the above-noted products.

2. Summary of Significant Accounting Policies

Significant Accounting Policies

Basis of Presentation. Our consolidated financial statements include our refined products, crude oil and marine storage operating segments. We consolidate all entities in which we have a controlling ownership interest. We apply the equity method of accounting to investments in entities over which we exercise significant influence but do not control. We eliminate all intercompany transactions.

Reclassifications. Prior year amounts related to restricted cash have been reclassified to conform with the current period's presentation.

Use of Estimates. The preparation of our consolidated financial statements in conformity with U.S. generally accepted accounting principles ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities that exist at the date of our consolidated financial statements, as well as their impact on the reported amounts of revenue and expense during the reporting periods. Actual results could differ from those estimates.

Cash Equivalents. Cash and cash equivalents include demand and time deposits and funds that own highly marketable securities with original maturities of three months or less when acquired. We periodically assess the financial condition of the institutions where we hold these funds, and, at December 31, 2017 and 2018, we believed our credit risk relative to these funds was minimal.

Restricted Cash. Restricted cash includes cash held by us, which is contractually required to be used for the construction of fixed assets and is unavailable for general use. It is classified as noncurrent due to its designation to be used for the construction of noncurrent assets.

Accounts Receivable and Allowance for Doubtful Accounts. Accounts receivable represent valid claims against customers. We recognize accounts receivable when we sell products or render services and collection of the receivable is probable. We extend credit terms to certain customers based on historical dealings and to other customers after a review of various credit indicators. We establish an allowance for doubtful accounts for all or any portion of an account where we consider collections to be at risk and evaluate reserves no less than quarterly to determine their adequacy. Judgments relative to at-risk accounts include the customers' current financial condition, the customers' historical relationship with us and current and projected economic conditions. We write off accounts receivable when we deem an account uncollectible.

Product Overages and Shortages. Each period end we measure the volume of each type of product in our pipeline systems and terminals, which is compared to the volumes of our customers' inventories (as adjusted for tender deductions). To the extent the product volumes in our pipeline systems and terminals exceed the volumes of our

customers' book inventories, we recognize a gain from the product overage and increase our product inventories. To the extent the product in our pipeline systems and terminals is less than our customers' book inventories, we recognize a loss from the product shortage and we record a liability for product owed to our customers. The product overages we recognize are recorded based on market prices, and the resulting inventory is carried at weighted average cost. The product shortages we recognize are recorded based on our weighted average cost. Additionally, when product shortages result in a net short inventory position, the related liability is recorded based on period-end

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MAGELLAN MIDSTREAM PARTNERS, L.P.
 NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

market prices. Product overages and shortages as well as adjustments to the value of net short inventory positions are recorded in operating expenses on our consolidated statements of income.

Income Taxes. We are a partnership for income tax purposes and, therefore, are not subject to federal or state income taxes for most of the states in which we operate. The tax on our net income is borne by our limited partners through allocation to them of their share of taxable income. Net income for financial statement purposes may differ significantly from taxable income of unitholders because of differences between the tax basis and financial reporting basis of assets and liabilities and the taxable income allocation requirements under our partnership agreement. The aggregate difference in the basis of our net assets for financial and tax reporting purposes cannot be readily determined because information regarding each partner’s tax attributes is not available to us.

The amounts recognized as provision for income taxes in our consolidated statements of income are primarily comprised of partnership-level taxes levied by the state of Texas. This tax is based on revenues less direct costs of sale for our assets apportioned to the state of Texas.

Net Income Per Unit. We calculate basic net income per limited partner unit for each period by dividing net income by the weighted-average number of limited partner units outstanding. The difference between our actual limited partner units outstanding and our weighted-average number of limited partner units outstanding used to calculate net income per limited partner unit is due to the impact of: (i) the phantom units issued to independent directors, which are included in the calculation of basic and diluted weighted average units outstanding and (ii) the weighted-average effect of units actually issued during a period. The difference between the weighted-average number of limited partner units outstanding used for basic and diluted net income per unit calculations on our consolidated statements of income is primarily the dilutive effect of phantom unit grants associated with our long-term incentive plan, which have not yet vested in periods where contingent performance metrics have been met.

Correction of Actuarial Valuation Error. In 2018, an error was discovered in our third-party actuary’s valuation of our pension liabilities and net periodic pension expenses dating back to 2010. The impacts of the error were not material to any of our prior period financial statements and the cumulative impact was corrected in 2018. As a result, net periodic pension expenses were increased by \$19.4 million (\$7.8 million operating expense, \$4.7 million general and administrative (“G&A”) costs and \$6.9 million other (income) expense below operating profit on our consolidated statements of income). In addition, long-term pension and benefits was increased \$22.2 million and accumulated other comprehensive loss was increased by \$2.8 million on our consolidated balance sheets.

Index of Additional Significant Accounting Policies

Revenue from Contracts with Customers	<u>Note 3 – Revenue</u>
Investments in Non-Controlled Entities	<u>Note 5 – Investments in Non-Controlled Entities</u>
Inventory	<u>Note 6 – Inventory</u>
Property, Plant and Equipment	<u>Note 7 – Property, Plant and Equipment</u>
Impairment of Long-Lived Assets	<u>Note 7 – Property, Plant and Equipment</u>
Goodwill and Other Intangible Assets	<u>Note 7 – Property, Plant and Equipment</u>

Pension and Postretirement Medical and Life Benefit Obligations

Note 9 – Employee Benefit Plans

Derivative Financial Instruments

Note 12 – Derivative Financial
Instruments

Equity-Based Incentive Compensation

Note 14 – Long-Term Incentive Plan

Contingencies and Environmental

Note 16 – Commitments and
Contingencies

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MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

New Accounting Pronouncements

In February 2016, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) 2016-02, Leases (Topic 842). This ASU requires lessees to recognize a right of use asset and lease liability on the balance sheet for all leases, with the exception of short-term leases. The new accounting model for lessors remains largely the same, although some changes have been made to align it with the new lessee model and the new revenue recognition guidance. This update also requires companies to include additional disclosures regarding their lessee and lessor agreements. For public companies, this ASU is effective for fiscal years that start after December 15, 2018, and early adoption is permitted. This standard will not have a material impact on our consolidated statements of income or our leverage ratio as defined in our credit agreement. Based on our current population of leases, we expect the impact of this ASU to increase our assets and liabilities by approximately \$180.0 million due to the recognition of right of use assets and lease liabilities.

New Accounting Pronouncements - Adopted by us on January 1, 2018

In August 2017, the FASB issued ASU 2017-12, Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities. This update changes GAAP’s hedge accounting requirements to simplify some of the specialized treatment’s most complex areas. These simplifications are intended to expand opportunities to use hedge accounting and better align the accounting treatment with existing risk management activities. The ASU is effective for public companies starting after December 15, 2018, and we early-adopted the new standard on January 1, 2018. The adoption of this ASU did not have a material impact on our consolidated financial statements.

In August 2016, the FASB issued ASU 2016-15, Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments: A Consensus of the FASB Emerging Issues Task Force. This ASU includes a requirement to make an accounting policy election to classify distributions received from equity method investees under either (1) the cumulative earnings approach, where distributions in excess of equity earnings are considered a return of capital and classified as cash inflows from investing activities, or (2) the nature of the distribution approach, where each distribution is evaluated on the basis of the source of the payment and classified as either operating or investing cash inflows. We adopted this standard on January 1, 2018 using the retrospective transition method and made an accounting policy election to use the nature of the distribution approach, which resulted in the following adjustments to our December 31, 2016 and 2017 comparative statements of cash flows (in thousands):

	Year Ended December 31, 2016			Year Ended December 31, 2017		
	As Reported	ASU 2016-15 Adjustment	As Adjusted	As Reported	ASU 2016-15 Adjustment	As Adjusted
Operating activities:						
Distributions from operations of non-controlled entities	\$78,723	\$ 9,264	\$87,987	\$123,660	\$ 22,551	\$146,211
Net cash provided by operating activities	\$964,040	\$ 9,264	\$973,304	\$1,108,678	\$ 22,551	\$1,131,229
Investing activities:						
	\$9,264	\$ (9,264)	\$—	\$78,482	\$ (22,551)	\$55,931

Distributions from returns of
investments in non-controlled entities

Net cash used by investing activities \$(857,366) \$ (9,264) \$(866,630) \$(570,623) \$(22,551) \$(593,174)

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MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606). This ASU amends the existing accounting standards for revenue recognition and is based on the principle that revenue should be recognized to depict the transfer of goods or services to a customer at an amount that reflects the consideration a company expects to receive in exchange for those goods or services. On January 1, 2018, we adopted the new Accounting Standards Codification (“ASC”) 606, Revenue from Contracts with Customers and all related amendments using the modified retrospective method. We recognized the cumulative effect of initially applying the new revenue standard as an adjustment to the opening balance of partners’ capital. The comparative information has not been restated and continues to be reported under the accounting standards in effect for those periods.

The cumulative effect of the changes made to our consolidated January 1, 2018 balance sheet resulting from the adoption of the new revenue standard was as follows (in thousands):

	Balance at December 31, 2017	Adjustments Due to ASU 2014-09	Balance at January 1, 2018
Assets:			
Property, plant and equipment	\$7,235,468	\$ 8,516	\$7,243,984
Accumulated depreciation	(1,682,633)	(325)	(1,682,958)
Net property, plant and equipment	\$5,552,835	\$ 8,191	\$5,561,026
Investments in non-controlled entities	\$1,082,511	\$ 502	\$1,083,013
Liabilities:			
Deferred revenue	\$117,795	\$ (1,901)	\$115,894
Other noncurrent liabilities	\$30,350	\$ 4,619	\$34,969
Partners’ capital:			
Limited partner unitholders	\$2,267,231	\$ 5,975	\$2,273,206

The primary changes impacting our financial statements under the new revenue standard include the requirement for us to estimate deficiencies in our customers’ use of our services contracted as minimum commitments and adjust the amount of revenue recognized in proportion to our customers’ pattern of exercised rights. This change results in accelerating the timing of revenue recognized for specific contracts for which we estimate our customers will not ship their minimum commitments. In addition, we periodically receive payments from customers seeking to expand their access to our pipeline systems and terminals. Prior to the adoption of the new revenue standard, these payments were recorded as reductions to our property, plant and equipment (“PP&E”) expenditures. Under the new revenue standard, these payments are recorded to deferred revenue and other noncurrent liabilities and are recognized as revenue in proportion to the related services provided. The impact of this change increases our revenues, contract liabilities, PP&E and depreciation expense. We expect the impact of the adoption of the new revenue standard, including these changes, to be immaterial to our net income on an ongoing basis.

MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

3. Revenue

Adoption of ASC 606, Revenue from Contracts with Customers

The table below provides the amount by which financial statement line items are affected in the current reporting period by the application of the new revenue standard, as compared with the guidance that was in effect before the change (in thousands):

	As Reported	Amounts without adoption of ASC 606	Effect of Change Higher/(Lower)
Statements of Income:			
	Year Ended December 31, 2018		
Transportation and terminals revenue	\$1,878,988	\$1,871,471	\$ 7,517
Depreciation, amortization and impairment	\$265,077	\$264,733	\$ 344
Balance Sheet:			
	As of December 31, 2018		
Assets:			
Property, plant and equipment	\$7,628,592	\$7,610,591	\$ 18,001
Accumulated depreciation	1,830,411	1,829,742	669
Net property, plant and equipment	\$5,798,181	\$5,780,849	\$ 17,332
Investments in non-controlled entities	\$1,076,306	\$1,075,805	\$ 501
Liabilities:			
Deferred revenue	\$121,085	\$125,717	\$ (4,632)
Other noncurrent liabilities	\$82,240	\$72,922	\$ 9,318
Partners' capital:			
Limited partner unitholders	\$2,763,925	\$2,750,778	\$ 13,147

Revenue recognition policies

Revenue is recognized upon the satisfaction of each performance obligation required by our customer contracts. Transportation and terminals revenue is recognized over time as our customers receive the benefits of our service as it is performed on their behalf using an output method based on actual deliveries. Revenue for our storage services is recognized over time using an output method based on the capacity of storage under contract with our customers. Product sales revenue is recognized at a point in time when our customers take control of the commodities purchased. We record back-to-back purchases and sales of petroleum products where we are acting as an agent on a net basis.

We recognize pipeline transportation revenue for crude oil and ammonia shipments when our customers' product arrives at the customer-designated destination. For shipments of refined products under published tariffs that combine transportation and terminalling services, we recognize revenue when our customers take delivery of their product from our system. For shipments where terminalling services are not included in the tariff, we recognize revenue when our customers' product arrives at the customer-designated destination. We have certain contracts that require counterparties to ship a minimum volume over an agreed-upon time period, which are contracted as minimum dollar or volume

commitments. Revenue pursuant to these take-or-pay contracts is recognized when the customers utilize their committed volumes. Additionally, when we estimate that the customers will not utilize all or a portion of their committed volumes, we recognize revenue in proportion to the pattern of exercised rights for the respective commitment period.

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MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

Our interstate common carrier petroleum products pipeline operations are subject to rate regulation by the Federal Energy Regulatory Commission (“FERC”) under the Interstate Commerce Act, the Energy Policy Act of 1992 and rules and orders promulgated pursuant thereto. FERC regulation requires that interstate pipeline rates be filed with the FERC, be posted publicly and be nondiscriminatory and “just and reasonable.” The rates on approximately 40% of the shipments on our refined products pipeline system are regulated by the FERC primarily through an index methodology. As an alternative to cost-of-service or index-based rates, interstate pipeline companies may establish rates by obtaining authority to charge market-based rates in competitive markets or by negotiation with unaffiliated shippers. Approximately 60% of our refined products pipeline system’s markets are either subject to regulations by the states in which we operate or are approved for market-based rates by the FERC, and in both cases these rates can generally be adjusted at our discretion based on market factors. Most of the tariffs on our crude oil pipelines are established by negotiated rates that generally provide for annual adjustments in line with changes in the FERC index, subject to certain modifications.

For both our index-based rates and our market-based rates, our published tariffs serve as contracts, and shippers nominate the volume to be shipped up to a month in advance. These tariffs include provisions which allow us to deduct from our customer’s inventory a small percentage of the products our customers transport on our pipeline systems. We refer to this non-monetary consideration as tender deduction revenue. We receive tender deductions from our customers as consideration for product losses during the transportation of petroleum products within our pipeline systems. Tender deduction revenue is generally recognized as transportation revenue when the customer's transported commodities reach their destination and is recorded at the fair value of the product received on the date received or the contract date, as applicable.

Product sales revenue pricing is contractually specified, and we have determined that each barrel sold represents a separate performance obligation. Transaction prices for our other services including terminalling, storage and ancillary services are typically contracted as a single performance obligation with our customers. In circumstances where multiple performance obligations are contractually required, we allocate the transaction price to the various performance obligations based on their relative standalone selling price.

MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

Statement of Income Disclosures

The following tables provide details of our revenues disaggregated by key activities that comprise our performance obligations by operating segment (in thousands):

	Year Ended December 31, 2018				
	Refined Products	Crude Oil	Marine Storage	Intersegment Eliminations	Total
Transportation	\$749,266	\$337,690	\$—	\$—	\$1,086,956
Terminalling	179,999	6,365	2,649	—	189,013
Storage	100,564	119,606	135,963	(3,691)	352,442
Ancillary services	111,009	25,590	25,674	—	162,273
Lease revenue	11,142	60,598	16,564	—	88,304
Transportation and terminals revenue	1,151,980	549,849	180,850	(3,691)	1,878,988
Product sales revenue	872,144	46,767	8,309	—	927,220
Affiliate management fee revenue	1,512	14,832	4,021	—	20,365
Total revenue	2,025,636	611,448	193,180	(3,691)	2,826,573
Revenue not under the guidance of ASC 606:					
Lease revenue ⁽¹⁾	(11,142)	(60,598)	(16,564)	—	(88,304)
(Gains) losses from futures contracts included in product sales revenue ⁽²⁾	(85,643)	632	—	—	(85,011)
Affiliate management fee revenue	(1,512)	(14,832)	(4,021)	—	(20,365)
Total revenue from contracts with customers under ASC 606	\$1,927,339	\$536,650	\$172,595	\$(3,691)	\$2,632,893

⁽¹⁾ Lease revenue is accounted for under ASC 840, Leases.

⁽²⁾ The impact on product sales revenue from futures contracts falls under the guidance of ASC 815, Derivatives and Hedging.

Balance Sheet Disclosures

We invoice customers on our refined products pipelines for transportation services when their product enters our system. At each period end, we record all invoiced amounts associated with products that have not yet been delivered (in-transit products) as a contract liability. This liability is presented as deferred revenue on our consolidated balance sheets. Deferred revenue is also recorded for pre-payments received in conjunction with take-or-pay contracts, storage contracts and other service offerings in which the service to our customers remains unfulfilled. Additionally, at each period end, we defer the direct costs we have incurred associated with our customers' in-transit products as contract assets. Contract assets are presented on our consolidated balance sheets as other current assets. These direct costs are estimated based on our per-barrel direct delivery cost for the current period multiplied by the total in-transit barrels in our system at the end of the period multiplied by 50% to reflect the average transportation costs incurred for all products across all of our pipeline systems. We use 50% of the in-transit barrels because that best represents the average delivery point of all barrels in our pipeline system. These contract assets and contract liabilities are determined using judgments and assumptions that management considers reasonable.

MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

The following table summarizes our accounts receivable, contract assets and contract liabilities resulting from contracts with customers (in thousands):

	January 1, 2018	December 31, 2018
Accounts receivable from contracts with customers	\$ 133,084	\$ 102,684
Contract assets	\$ 8,615	\$ 8,487
Contract liabilities	\$ 106,933	\$ 122,129

For the year ended December 31, 2018, we recognized \$79.3 million of transportation and terminals revenue that was recorded in deferred revenue as of January 1, 2018.

Unfulfilled Performance Obligations

We have certain contracts with customers that represent customer commitments to purchase a minimum amount of our services over specified time periods. These contracts require us to provide services to our customers in the future and result in our having unfulfilled performance obligations (“UPOs”) to our customers related to the periods remaining under each contract. We have UPOs in many of our core business services, including transportation, terminalling and storage services. The UPOs will be recognized as revenue in the future as our customers utilize our services or when we estimate that our customers are not likely to use all or a portion of their commitments.

The following table provides the aggregate amount of the transaction price allocated to our UPOs as of December 31, 2018 by operating segment, including the range of years remaining on our contracts with customers and an estimate of revenues expected to be recognized over the next 12 months (dollars in thousands):

	Refined Products	Crude Oil	Marine Storage	Total
Balances at December 31, 2018	\$2,116,001	\$1,310,734	\$334,403	\$3,761,138
Remaining terms	1 - 20 years	1 - 10 years	1 - 6 years	
Estimated revenues from UPOs to be recognized in the next 12 months	\$285,730	\$318,919	\$151,035	\$755,684

In computing the value of these future revenues, we have used the current rates in effect as of December 31, 2018 and have not included any estimates for future rate changes due to changes in the FERC index or other contractually negotiated rate escalations. Our UPO balances include the full amount of our customer commitments as of December 31, 2018 through the expiration of the related contracts. The UPO balances disclosed exclude all performance obligations for which the original expected term is one year or less, the consideration is variable or the future use of our services is fully at the discretion of our customers.

MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

4. Consolidated Statements of Cash Flows

Changes in the components of operating assets and liabilities are as follows (in thousands):

	Year Ended December 31,		
	2016	2017	2018
Trade accounts receivable and other accounts receivable	\$(31,107)	\$(25,639)	\$24,169
Inventory	(3,510)	(47,967)	(3,390)
Energy commodity derivatives contracts, net of derivatives deposits	(692)	8,556	(7,078)
Accounts payable	(4,423)	8,954	21,146
Accrued payroll and benefits	(6,074)	10,596	14,015
Accrued interest payable	14,347	5,014	(7,399)
Accrued taxes other than income	(1,421)	1,177	1,750
Deferred revenue	20,264	15,904	5,191
Accrued product liabilities	20,261	44,559	(20,677)
Current and noncurrent environmental liabilities	(7,398)	(4,766)	1,226
Other current and noncurrent assets and liabilities	(21,762)	(693)	(6,707)
Total	\$(21,515)	\$15,695	\$22,246

Other current and noncurrent assets and liabilities above exclude certain non-cash items that were reflected in the consolidated balance sheets but were not reflected in the statements of cash flows. At December 31, 2016, 2017 and 2018, the long-term pension and benefits liability was increased by \$2.5 million, \$46.0 million and \$2.3 million, respectively, resulting in a corresponding increase in accumulated other comprehensive loss (“AOCL”).

5. Investments in Non-Controlled Entities

We account for interests in affiliates that we do not control using the equity method of accounting. Under this method, an investment is recorded at our acquisition cost or capital contributions, as adjusted by contractual terms, plus equity in earnings or losses since acquisition or formation, plus interest capitalized, less distributions received and amortization of interest capitalized and excess net investment. Excess net investment is the amount by which our investment in a non-controlled entity exceeded our proportionate share of the book value of the net assets of that investment. We amortize excess net investment over the weighted-average depreciable asset lives of the equity investee. Our unamortized excess net investment was \$59.7 million and \$34.8 million at December 31, 2017 and 2018, respectively. The amount of unamortized excess investment is primarily related to our investment in BridgeTex. We evaluate equity method investments for impairment whenever events or circumstances indicate that there is an other-than-temporary loss in value of the investment. In the event that we determine that the loss in value of an investment is other-than-temporary, we would record a charge to earnings to adjust the carrying value to fair value. We recognized no equity investment impairments during 2016, 2017 and 2018.

MAGELLAN MIDSTREAM PARTNERS, L.P.
 NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

Our investments in non-controlled entities at December 31, 2018 were comprised of:

Entity	Ownership Interest
BridgeTex Pipeline Company, LLC (“BridgeTex”)	30%
Double Eagle Pipeline LLC (“Double Eagle”)	50%
HoustonLink Pipeline Company, LLC (“HoustonLink”)	50%
MVP Terminalling, LLC (“MVP”)	50%
Powder Springs Logistics, LLC (“Powder Springs”)	50%
Saddlehorn Pipeline Company, LLC (“Saddlehorn”)	40%
Seabrook Logistics, LLC (“Seabrook”)	50%
Texas Frontera, LLC (“Texas Frontera”)	50%

In September 2018, we sold a 20% interest in BridgeTex to an affiliate of OMERS Infrastructure Management Inc. (“OMERS”), which reduced our ongoing ownership in BridgeTex to a 30% interest. We received \$575.6 million in net proceeds from the sale, and we recorded a gain of \$353.8 million on our consolidated statements of income. See Note 16 – Commitments and Contingencies for details regarding our indemnity to OMERS that was recorded in relation to the sale.

We own a 50% equity interest in MVP, with an affiliate of Valero Energy Corporation (“Valero”) owning the other 50% interest. Upon formation of MVP in September 2017, we contributed \$97.6 million of PP&E to this entity. Concurrently, Valero contributed cash of \$48.8 million, which was distributed to us as reimbursement for Valero’s portion of the PP&E we contributed. The \$48.8 million is reflected as distributions from returns of investments in non-controlled entities on our consolidated statements of cash flows.

We serve as operator of BridgeTex, HoustonLink, MVP, Powder Springs, Saddlehorn, Texas Frontera and the pipeline activities of Seabrook. We receive fees for management services as well as reimbursement or payment to us for certain direct operational payroll and other overhead costs. The management fees we have received are reported as affiliate management fee revenue on our consolidated statements of income. Cost reimbursements we receive from these entities in connection with our operating services are included as reductions to costs and expenses on our consolidated statements of income and totaled \$4.2 million, \$3.6 million and \$3.9 million, respectively, for the years ended December 31, 2016, 2017 and 2018.

MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

We recorded the following revenue and expense transactions from certain of these non-controlled entities in our consolidated statements of income (in millions):

	Year Ended		
	December 31,		
	2016	2017	2018
Transportation and terminals revenue:			
BridgeTex, capacity lease	\$35.5	\$36.1	\$39.6
Double Eagle, throughput revenue	\$3.3	\$4.7	\$5.2
Saddlehorn, storage revenue	\$0.7	\$2.1	\$2.2
Operating costs:			
Seabrook, storage and ancillary services	\$—	\$—	\$10.6
MVP, sale of air emission reduction credits (reduction of operating costs)	\$—	\$—	\$(2.2)
Product sales revenue:			
Powder Springs, butane sales	\$—	\$—	\$4.9
Cost of product sales:			
BridgeTex, transportation charges	\$—	\$14.5	\$—
Powder Springs, butane purchases	\$—	\$—	\$0.4

Our consolidated balance sheets reflected the following balances related to our investments in non-controlled entities (in millions):

	December 31, 2017			December 31, 2018			Long-Term Receivables
	Trade Accounts Receivable	Other Accounts Receivable	Other Accounts Payable	Trade Accounts Receivable	Other Accounts Receivable	Other Accounts Payable	
BridgeTex	\$—	\$—	\$—	\$0.3	\$1.5	\$—	\$—
Double Eagle	\$0.5	\$—	\$—	\$0.5	\$—	\$—	\$—
HoustonLink	\$—	\$—	\$0.1	\$—	\$—	\$—	\$—
MVP	\$—	\$0.4	\$—	\$—	\$0.4	\$—	\$—
Powder Springs	\$—	\$0.9	\$—	\$—	\$—	\$—	\$2.2
Saddlehorn	\$—	\$0.1	\$—	\$—	\$0.2	\$—	\$—
Seabrook	\$—	\$0.2	\$—	\$—	\$—	\$1.1	\$—

We have entered into a long-term lease for 1.7 million barrels of storage from Seabrook (see Note 13 – Leases for future minimum annual rentals under this lease) which is connected to our Houston distribution system. This agreement also provides us with designated access to Seabrook's docks for crude oil import and export opportunities. We in turn generate revenue by providing this storage capacity and dock access to our third-party customers.

We incurred charges for transportation of crude oil at published spot tariff rates on the BridgeTex pipeline of \$14.5 million for the year ended December 31, 2018, which were recorded as cost of product sales in our consolidated statements of income. We purchased inventory from BridgeTex valued at \$6.7 million during 2017.

The financial results from MVP and Texas Frontera are included in our marine storage segment, the financial results from BridgeTex, Double Eagle, HoustonLink, Saddlehorn and Seabrook are included in our crude oil

MAGELLAN MIDSTREAM PARTNERS, L.P.
 NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

segment and the financial results from Powder Springs are included in our refined products segment, each as earnings of non-controlled entities.

A summary of our investments in non-controlled entities (representing only our proportionate interests) follows (in thousands):

Investments at December 31, 2017	\$1,082,511
Additional investment	216,424
Sale of ownership interest in BridgeTex	(205,776)
Other adjustments	502
Earnings of non-controlled entities:	
Proportionate share of earnings	183,317
Amortization of excess investment and capitalized interest	(2,200)
Earnings of non-controlled entities	181,117
Less:	
Distributions from operations of non-controlled entities	196,686
Distributions from returns of investments in non-controlled entities	1,786
Investments at December 31, 2018	\$1,076,306

Summarized financial information of our non-controlled entities (representing 100% of the interests in these entities) follows (in thousands):

	December 31,	
	2017	2018
Current assets	\$229,342	\$258,698
Noncurrent assets	2,057,892	2,461,456
Total assets	\$2,287,234	\$2,720,154
Current liabilities	\$122,198	\$170,558
Noncurrent liabilities	74,533	73,700
Total liabilities	\$196,731	\$244,258
Equity	\$2,090,503	\$2,475,896

	Year Ended December 31,		
	2016	2017	2018
Revenue	\$279,180	\$419,214	\$631,420
Net income	\$164,684	\$256,423	\$416,128

MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

6. Inventory

Inventory is comprised primarily of refined products, liquefied petroleum gases, transmix, crude oil and additives, which are stated and relieved at the lower of average cost or net realizable value.

Inventory at December 31, 2017 and 2018 was as follows (in thousands):

	December 31,	
	2017	2018
Refined products	\$73,845	\$92,751
Liquefied petroleum gases	45,553	46,612
Transmix	33,319	28,497
Crude oil	23,763	11,220
Additives	5,865	6,655
Total inventory	\$182,345	\$185,735

During 2018, we recorded lower of average cost or net realizable value adjustments of \$18.5 million related to our refined products, transmix and crude oil inventories.

7. Property, Plant and Equipment, Goodwill and Other Intangibles

Property, Plant and Equipment

Property, plant and equipment consist primarily of pipeline, pipeline-related equipment, storage tanks and processing equipment. We state property, plant and equipment at cost except for certain acquired assets recorded at fair value on their respective acquisition dates and impaired assets. We record impaired assets at fair value on the last impairment evaluation date for which an adjustment was required.

We assign asset lives based on reasonable estimates when we place an asset into service. Subsequent events could cause us to change our estimates, which would affect the future calculation of depreciation expense.

When we sell or retire property, plant and equipment, we remove its carrying value and the related accumulated depreciation from our accounts and record any associated gains or losses on our consolidated statements of income in the period of sale or disposition.

We capitalize expenditures to replace existing assets and retire the replaced assets. We capitalize expenditures when they extend the useful life, increase the productivity or capacity or improve the safety or efficiency of the asset. We capitalize direct project costs such as labor and materials as incurred. Indirect project costs, such as overhead, are capitalized based on a percentage of direct labor charged to the respective capital project. We charge expenditures for maintenance, repairs and minor replacements to operating expense in the period incurred.

During construction, we capitalize interest on all construction projects requiring a completion period of three months or longer and total project costs exceeding \$0.5 million. The interest we capitalize is based on the weighted-average interest rate of our debt. The weighted average rates used to capitalize interest on borrowed funds were 4.9%, 4.8%

and 4.8% for the years ended December 31, 2016, 2017 and 2018, respectively.

MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

Property, plant and equipment consisted of the following (in thousands):

	December 31,		Estimated
	2017	2018	Depreciable Lives
Construction work-in-progress	\$ 389,414	\$ 395,184	
Land and rights-of-way	303,797	303,485	
Buildings	114,899	119,720	10 to 53 years
Storage tanks	1,897,046	2,059,244	10 to 40 years
Pipeline and station equipment	2,581,950	2,614,855	10 to 59 years
Processing equipment	1,703,478	1,875,029	3 to 56 years
Other	244,884	261,075	3 to 53 years
Property, Plant and Equipment, Gross	\$ 7,235,468	\$ 7,628,592	

Other includes total interest capitalized on construction in progress as of December 31, 2017 and 2018 of \$57.3 million and \$67.6 million, respectively. Depreciation expense for the years ended December 31, 2016, 2017 and 2018 was \$176.7 million, \$196.3 million and \$214.4 million, respectively.

Goodwill

We record the excess of purchase price over the fair value of the tangible and identifiable intangible assets acquired and liabilities assumed as goodwill. The goodwill relating to each of our reporting units is tested for impairment annually as well as when an event, or change in circumstances, indicates an impairment may have occurred.

For purposes of performing the impairment test for goodwill, our reporting units are refined products, crude oil and marine storage. In 2016, we elected to perform the qualitative assessment for purposes of our annual goodwill impairment test. Based on this assessment, we concluded that it was more likely than not that the fair value of each of our reporting units was greater than its carrying amount. In 2017 and 2018, we elected to complete the quantitative goodwill impairment test and began with step one of the test as required by ASC 350-20-35-4. Based on this assessment, we concluded that our goodwill was not impaired.

Long-Lived Assets and Other Intangibles

Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying value may not be recoverable. In reviewing for impairment, the carrying value of such assets is compared to the estimated undiscounted future cash flows expected from the use of the assets and their eventual disposition. If such cash flows are not sufficient to support the asset's recorded value, an impairment charge is recognized to reduce the carrying value of the long-lived asset to its estimated fair value. The determination of future cash flows as well as the estimated fair value of long-lived assets involves significant estimates on the part of management.

During 2018, we made the decision to discontinue commercial operations of our ammonia pipeline beginning in late 2019 due to the system's low profitability and challenging economic outlook. As a result, operations will end in conjunction with the expiry of our existing customer commitments, primarily by late 2019. We have estimated the fair value of the ammonia pipeline assets based on expected future cash flows and recognized a \$49.1 million

impairment charge in depreciation, amortization and impairment expense on our consolidated statements of income.

Other intangible assets with finite lives are amortized over their estimated useful lives of seven years up to 30 years. The weighted-average asset life of our other intangible assets at December 31, 2018 was approximately 20

MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

years. We adjust the useful lives of our other intangible assets if events or circumstances indicate there has been a change in the remaining useful lives. We eliminate from our balance sheets the gross carrying amount and the related accumulated amortization for any fully amortized intangibles in the year they are fully amortized. During the years ended December 31, 2016, 2017 and 2018, amortization of other intangible assets was \$1.4 million, \$0.4 million and \$1.6 million, respectively.

8. Major Customers and Concentration of Risks

Major Customers. No customer accounted for more than 10% of our consolidated revenues during 2016, 2017 or 2018.

Concentration of Risks. We transport, store and distribute petroleum products for refiners, producers, marketers, traders and end users of those products. Our revenue producing activities are concentrated in the central U.S. Concentrations of customers may affect our overall credit risk as our customers may be similarly affected by changes in economic, regulatory or other factors. We generally secure transportation and storage revenue with warehouseman's liens. We periodically evaluate the financial condition and creditworthiness of our customers and require additional security as we deem necessary.

As of December 31, 2018, we had 1,868 employees, 948 of which were assigned to our refined products segment and concentrated in the central U.S. Approximately 24% of the 948 employees are represented by the United Steel Workers ("USW") and were covered by a collective bargaining agreement that expired in January 2019 (see Note 19—Subsequent Events for additional information regarding the renegotiation of this agreement). At December 31, 2018, 160 of our employees were assigned to our crude oil segment and were concentrated in the central U.S., and none of these employees were covered by a collective bargaining agreement. There were 201 employees assigned to our marine storage segment at December 31, 2018, primarily in the Gulf and East Coast regions of the U.S., with approximately 14% of these employees represented by the International Union of Operating Engineers ("IUOE") and covered by a collective bargaining agreement that expires in October 2020.

9. Employee Benefit Plans

Our pension and postretirement benefit liabilities represent the funded status of the present value of benefit obligations of our employee benefit plans. We develop pension, postretirement medical and life benefit costs from actuarial valuations. We establish actuarial assumptions to anticipate future events and use those assumptions when calculating the expense and liabilities related to these plans. These factors include assumptions management makes concerning expected investment return on plan assets, discount rates, health care costs trend rates, turnover rates and rates of future compensation increases, among others. In addition, we use subjective factors such as withdrawal and mortality rates to develop actuarial valuations. Management reviews and updates these assumptions on an annual basis. The actuarial assumptions that we use may differ from actual results due to changing market rates or other factors. These differences could affect the amount of pension and postretirement medical and life benefit expense we will recognize in future periods.

Defined Contribution Plan. We sponsor a defined contribution plan in which we match our employees' qualifying contributions, resulting in additional expense to us. Expenses related to the defined contribution plan were \$9.6 million, \$9.9 million and \$11.0 million in 2016, 2017 and 2018, respectively.

Defined Benefit Plans. We sponsor two union pension plans that cover certain union employees (“USW plan” and “IUOE plan,” collectively, the “Union plans”), a pension plan for all non-union employees (“Salaried plan”) and a postretirement benefit plan for certain employees. The annual measurement date of these plans is December 31.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

The following table presents the changes in benefit obligations and plan assets for pension benefits and other postretirement benefits, as well as the end-of-period accumulated benefit obligation for the years ended December 31, 2017 and 2018 (in thousands):

	Pension Benefits		Other Postretirement Benefits	
	2017	2018	2017	2018
Change in benefit obligations:				
Benefit obligations at beginning of year	\$225,970	\$297,856	\$13,011	\$12,760
Service cost	20,497	38,167	243	243
Interest cost	9,865	14,907	475	416
Plan participants' contributions	—	—	280	357
Actuarial loss (gain)	59,686	(21,375)	(535)	(599)
Benefits paid	(11,484)	(14,356)	(714)	(1,097)
Settlement payments	(6,678)	(6,250)	—	—
Benefit obligations at end of year	297,856	308,949	12,760	12,080
Change in plan assets:				
Fair value of plan assets at beginning of year	166,906	198,686	—	—
Employer contributions	26,533	31,717	434	740
Plan participants' contributions	—	—	280	357
Actual return (loss) on plan assets	23,409	(12,207)	—	—
Benefits paid	(11,484)	(14,356)	(714)	(1,097)
Settlement payments	(6,678)	(6,250)	—	—
Fair value of plan assets at end of year	198,686	197,590	—	—
Funded status at end of year	\$(99,170)	\$(111,359)	\$(12,760)	\$(12,080)
Accumulated benefit obligations	\$206,480	\$208,840		

The pension benefits in the previous table combine the Union plans with the Salaried plan. At December 31, 2017, the Salaried and IUOE plans had combined accumulated benefit obligations of \$154.4 million, which exceeded the combined fair value of plan assets of \$145.9 million. At December 31, 2018, the accumulated benefit obligations of each of our plans exceeded the fair value of the related plans' assets.

The pension benefit obligations experienced an actuarial loss of \$59.7 million in 2017 primarily due to the impact of decreases in the discount rates used to calculate the benefit obligations and changes to mortality assumptions, as well as losses due to annual remeasurement of the plans.

MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

Amounts recognized in the consolidated balance sheets included in these financial statements were as follows (in thousands):

	Pension Benefits		Other Postretirement Benefits	
	2017	2018	2017	2018
Amounts recognized in consolidated balance sheets:				
Current accrued benefit cost	\$—	\$—	\$625	\$859
Long-term pension and benefits	99,170	111,359	12,135	11,221
	99,170	111,359	12,760	12,080
Accumulated other comprehensive loss:				
Net actuarial loss	(100,474)	(91,669)	(6,597)	(5,409)
Prior service credit	3,248	3,067	—	—
	(97,226)	(88,602)	(6,597)	(5,409)
Net amount of liabilities and accumulated other comprehensive loss recognized in consolidated balance sheets	\$1,944	\$22,757	\$6,163	\$6,671

Net periodic benefit expense for the years ended December 31, 2016, 2017 and 2018 was as follows (in thousands):

	Pension Benefits			Other Postretirement Benefits		
	2016	2017	2018	2016	2017	2018
Components of net periodic pension and postretirement benefit expense:						
Service cost	\$18,179	\$20,497	\$38,167	\$235	\$243	\$243
Interest cost	7,950	9,865	14,907	489	475	416
Expected return on plan assets	(8,913)	(10,266)	(12,090)	—	—	—
Amortization of prior service credit	(181)	(181)	(181)	(3,335)	—	—
Amortization of actuarial loss	4,645	5,622	9,763	880	749	589
Settlement cost	202	2,460	1,964	—	—	—
Net periodic expense (credit)	\$21,882	\$27,997	\$52,530	\$(1,731)	\$1,467	\$1,248

The service component of our net periodic benefit expense (credit) is presented in operating expense and G&A expense, and the non-service components are presented in other (income) expense in our consolidated statements of income.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

Changes in plan assets and benefit obligations recognized in other comprehensive income (loss) during 2016, 2017 and 2018 were as follows (in thousands):

	Pension Benefits			Other Postretirement Benefits		
	2016	2017	2018	2016	2017	2018
Beginning balance	\$(62,279)	\$(58,584)	\$(97,226)	\$(3,945)	\$(7,881)	\$(6,597)
Net actuarial gain (loss)	(971)	(46,543)	(2,922)	(1,481)	535	599
Amortization of prior service credit	(181)	(181)	(181)	(3,335)	—	—
Amortization of actuarial loss	4,645	5,622	9,763	880	749	589
Settlement cost	202	2,460	1,964	—	—	—
Amount recognized in other comprehensive loss	3,695	(38,642)	8,624	(3,936)	1,284	1,188
Ending balance	\$(58,584)	\$(97,226)	\$(88,602)	\$(7,881)	\$(6,597)	\$(5,409)

The net periodic benefit costs and AOCL presented in the tables above for the year ended December 31, 2018 include corrections resulting from an error in our third-party actuary's valuation of our pension liabilities and net periodic pension expenses. See Note 2 – Summary of Significant Accounting Policies for more details regarding this error correction.

Actuarial gains and losses are amortized over the average future service period of current active plan participants expected to receive benefits. The corridor approach is used to determine when actuarial gains and losses are to be amortized and is equal to 10% of the greater of the projected benefit obligation or the market related value of plan assets. The amount of gain or loss in excess of the calculated corridor is subject to amortization. The estimated net actuarial loss and prior service credit for the defined benefit pension plans that will be amortized from AOCL into net periodic benefit cost in 2019 are \$5.1 million and \$0.2 million, respectively. The estimated net actuarial loss for the other defined benefit postretirement plan that will be amortized from AOCL into net periodic benefit cost in 2019 is \$0.2 million.

The weighted-average rate assumptions used to determine benefit obligations were as follows:

	December 31,	
	2017	2018
Discount rate—Salaried plan	3.70%	3.99%
Discount rate—USW plan	3.54%	3.94%
Discount rate—IUOE plan	3.79%	4.12%
Discount rate—Other Postretirement Benefits	3.43%	4.08%
Rate of compensation increase—Salaried plan	4% - 11%	4% - 11%
Rate of compensation increase—USW plan	3.50%	3.50%
Rate of compensation increase—IUOE plan	5.00%	5.00%

(1) The rate of compensation increase assumption for the Salaried plan in 2017 and 2018 is calculated by 10-year age groupings beginning with ages 20-29 at 11% dropping to 4% by ages 70 and above.

MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

The weighted-average rate assumptions used to determine net pension and other postretirement benefit expense were as follows:

	For the Year Ended December		
	31, 2016	2017	2018
Discount rate—Salaried plan	3.95%	4.21%	3.70%
Discount rate—USW plan	3.82%	4.04%	3.63%
Discount rate—IUOE plan	3.78%	4.41%	3.79%
Discount rate—Other Postretirement Benefits	4%	3.85%	3.43%
Rate of compensation increase—Salaried plan	4% - 11%	4% - 11%	4% - 11%
Rate of compensation increase—USW plan	3.50%	3.50%	3.50%
Rate of compensation increase—IUOE plan	5.00%	5.00%	5.00%
Expected rate of return on plan assets—Salaried plan	6.00%	6.00%	6.00%
Expected rate of return on plan assets—USW plan	6.00%	6.00%	6.00%
Expected rate of return on plan assets—IUOE plan	6.00%	6.00%	6.00%

⁽¹⁾ The rate of compensation increase assumption for the Salaried plan is calculated by 10-year age groupings beginning with ages 20-29 at 11% dropping to 4% by ages 70 and above.

The non-pension postretirement benefit plans provide for retiree contributions and contain other cost-sharing features such as deductibles and coinsurance. The accounting for these plans anticipates future cost sharing that is consistent with management's expressed intent to increase the retiree contribution rate generally in line with health care cost increases.

The annual assumed rate of increase in the health care cost trend rate for 2019 is 5.8% decreasing systematically to 4.9% by 2066 for pre-65 year-old participants. As of December 31, 2018, a 1.0% change in assumed health care cost trend rates would have been immaterial to us.

MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

The fair values of the pension plan assets at December 31, 2017 were as follows (in thousands):

Asset Category	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Domestic Equity Securities ⁽¹⁾ :				
Small-cap fund	\$5,122	\$ 5,122	\$ —	—\$ —
Mid-cap fund	5,132	5,132	—	—
Large-cap fund	38,678	38,678	—	—
International equity fund	24,284	24,284	—	—
Fixed Income Securities ⁽¹⁾ :				
Short-term bond funds	5,110	5,110	—	—
Intermediate-term bond funds	25,875	25,875	—	—
Long-term investment grade bond funds	88,563	88,563	—	—
Other:				
Short-term investment funds	5,722	5,722	—	—
Group annuity contract	200	—	—	200
Fair value of plan assets	\$198,686	\$ 198,486	\$ —	—\$ 200

⁽¹⁾ We hold equity and fixed income securities through investments in mutual funds, which are dedicated to each category as indicated.

The fair values of the pension plan assets at December 31, 2018 were as follows (in thousands):

Asset Category	Total	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Domestic Equity Securities ⁽¹⁾ :				
Small-cap fund	\$3,816	\$ 3,816	\$ —	—\$ —
Mid-cap fund	3,811	3,811	—	—
Large-cap funds	30,595	30,595	—	—
International equity fund	19,471	19,471	—	—
Fixed Income Securities ⁽¹⁾ :				
Short-term bond funds	9,242	9,242	—	—
Intermediate-term bond funds	23,036	23,036	—	—
Long-term investment grade bond funds	99,118	99,118	—	—
Other:				
Short-term investment fund	8,312	8,312	—	—

Group annuity contract	189	—	—	189
Fair value of plan assets	\$197,590	\$ 197,401	\$	—\$ 189

(1) We hold equity and fixed income securities through investments in mutual funds, which are dedicated to each category as indicated.

As reflected in the tables above, Level 3 activity was not material.

MAGELLAN MIDSTREAM PARTNERS, L.P.
 NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

The investment strategies for the various funds held as pension plan assets by asset category are as follows:

Asset Category	Fund's Investment Strategy
Domestic Equity Securities:	
Small-cap fund	Seeks to track performance of the Center for Research in Security Prices ("CRSP") US Small Cap Index
Mid-cap fund	Seeks to track performance of the CRSP US Mid Cap Index
Large-cap funds	Seek to track performance of the Standard & Poor's 500 Index
International equity fund	Seeks long-term growth of capital by investing 65% or more of assets in international equities
Fixed Income Securities:	
Short-term bond funds	Seek current income with limited price volatility through investment in primarily high quality bonds
Intermediate-term bond funds	Seek moderate and sustainable level of current income by investing primarily in high quality fixed income securities with maturities from five to ten years
Long-term investment grade bond funds	Seek high and sustainable current income through investment primarily in long-term high grade bonds
Other:	
Short-term investment fund	Invests in high quality short-term money market instruments issued by the U.S. Treasury
Group annuity contract	Earns interest quarterly equal to the effective yield of the 91-day U.S. Treasury bill

The expected long-term rate of return on plan assets was determined by combining a review of projected returns, historical returns of portfolios with assets similar to the current portfolios of the union and non-union pension plans and target weightings of each asset classification. Our investment objective for the assets within the pension plans is to earn a return that meets or exceeds the growth of obligations that result from interest and changes in the discount rate, while avoiding excessive risk. Defined diversification goals are set in order to reduce the risk of wide swings in the market value from year to year, or of incurring large losses that may result from concentrated positions. As a result, our plan assets have no significant concentrations of credit risk. Additionally, liquidity risks are minimized because all of the funds that the plans have invested in are publicly traded. We evaluate risks based on the potential impact to the predictability of contribution requirements, probability of under-funding, expected risk-adjusted returns and investment return volatility. Funds are invested with multiple investment managers. Our liabilities are calculated using rates defined by the Pension Protection Act of 2006. Approximately 70% of the plan's investments are allocated to fixed-income securities and invested to match the durations of the plan's short, intermediate and long-term pension liabilities, with the amount invested in each duration reflecting that duration's proportion of the plan's liabilities. The remaining approximately 30% of the plan's investments are allocated to equity securities.

MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

The target allocation and actual weighted-average asset allocation percentages at December 31, 2017 and 2018 were as follows:

	2017		2018	
	Actual	Target	Actual	Target
Equity securities	37%	30%	29%	30%
Fixed income securities	60%	67%	67%	67%
Other	3%	3%	4%	3%

As of December 31, 2018, the benefit amounts expected to be paid from plan assets through December 31, 2028 were as follows (in thousands):

	Pension Benefits	Other Postretirement Benefits
2019	\$ 14,734	\$ 859
2020	\$ 17,278	\$ 901
2021	\$ 19,576	\$ 915
2022	\$ 22,606	\$ 913
2023	\$ 24,381	\$ 878
2024 through 2028	\$ 147,022	\$ 3,787

Contributions estimated to be paid by us into the plans in 2019 are \$32.1 million and \$0.9 million for the pension and other postretirement benefit plans, respectively.

10. Related Party Transactions

Barry R. Pearl is an independent member of our general partner's board of directors and was also a director of Targa Resources Partners, L.P. ("Targa") through February 29, 2016. In the normal course of business, we purchase butane from subsidiaries of Targa. During Mr. Pearl's tenure as a director of the general partner of Targa, we made purchases of butane from subsidiaries of Targa of \$4.7 million for the year ended December 31, 2016.

Stacy P. Methvin is an independent member of our general partner's board of directors and is also a director of one of our customers. We received tariff, terminalling and other ancillary revenue from this customer of \$16.2 million, \$16.6 million and \$21.7 million for the periods ending December 31, 2016, 2017 and 2018, respectively. We recorded a receivable of \$1.6 million and \$1.9 million from this customer at December 31, 2017 and 2018, respectively. The tariff revenue we recognized from this customer was in the normal course of business, with rates determined in accordance with published tariffs.

See Note 5 – Investments in Non-Controlled Entities for a discussion of transactions with our joint venture affiliates.

MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

11. Debt

Long-term debt at December 31, 2017 and 2018 was as follows (in thousands):

	December 31,	
	2017	2018
6.40% Notes due 2018	\$250,000	\$—
6.55% Notes due 2019 ⁽¹⁾	550,000	550,000
4.25% Notes due 2021	550,000	550,000
3.20% Notes due 2025	250,000	250,000
5.00% Notes due 2026	650,000	650,000
6.40% Notes due 2037	250,000	250,000
4.20% Notes due 2042	250,000	250,000
5.15% Notes due 2043	550,000	550,000
4.20% Notes due 2045	250,000	250,000
4.25% Notes due 2046	500,000	500,000
4.20% Notes due 2047	500,000	500,000
Face value of long-term debt	4,550,000	4,300,000
Unamortized debt issuance costs ⁽²⁾	(29,472)	(27,070)
Net unamortized debt premium (discount) ⁽²⁾	215	(2,927)
Net unamortized amount of gains from historical fair value hedges ⁽²⁾	3,749	866
Long-term debt, net, including current portion	4,524,492	4,270,869
Less: current portion of long-term debt, net ⁽¹⁾	250,974	59,489
Long-term debt, net	\$4,273,518	\$4,211,380

At December 31, 2018, we had the ability and the intent to refinance approximately \$490.0 million of our long-term notes maturing in 2019. As a result, only the portion of our debt that will be repaid with cash available as of December 31, 2018 is classified as current in our consolidated balance sheets. See Note 19 – Subsequent Events for details regarding proceeds received from our debt issuance in January 2019.

⁽²⁾ Debt issuance costs, note discounts and premiums and realized gains and losses of historical fair value hedges are being amortized or accreted to the applicable notes over the respective lives of those notes.

All of the instruments detailed in the table above are senior indebtedness.

At December 31, 2018, maturities of our debt were as follows: \$550.0 million in July 2019; \$0 in 2020; \$550 in 2021; \$0 in 2022; \$0 in 2023; and \$3.2 billion thereafter. See Note 19 – Subsequent Events for details regarding early redemption of the notes due in July 2019.

Other Debt

Revolving Credit Facility. At December 31, 2018, the total borrowing capacity under our revolving credit facility maturing October 26, 2022 was \$1.0 billion. Any borrowings outstanding under this facility are classified as long-term debt on our consolidated balance sheets. Borrowings under the facility are unsecured and bear interest at LIBOR plus a spread ranging from 1.000% to 1.625% based on our credit ratings. Additionally, an unused commitment fee is

assessed at a rate from 0.100% to 0.275% depending on our credit ratings. The unused commitment fee was 0.125% at December 31, 2018. Borrowings under this facility may be used for general purposes, including capital expenditures. As of December 31, 2017 and 2018, respectively, there were obligations

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MAGELLAN MIDSTREAM PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

for letters of credit of \$6.3 million and \$6.8 million, respectively. Amounts obligated for letters of credit are not reflected as debt on our consolidated balance sheets, but decrease our borrowing capacity under the facility. There were no borrowings outstanding under this facility at December 31, 2017 and 2018.

Our revolving credit facility requires us to maintain a specified ratio of consolidated debt to EBITDA (as defined in the credit agreement) of no greater than 5.0 to 1.0. In addition, the revolving credit facility and the indentures under which our senior notes were issued contain covenants that limit our ability to, among other things, incur indebtedness secured by certain liens or encumber our assets, engage in certain sale-leaseback transactions and consolidate, merge or dispose of all or substantially all of our assets. We were in compliance with these covenants as of and during the year ended December 31, 2018.

Commercial Paper Program. We have a commercial paper program under which we may issue commercial paper notes in an amount up to the available capacity under our \$1.0 billion revolving credit facility. The maturities of the commercial paper notes vary, but may not exceed 397 days from the date of issuance. Because the commercial paper we can issue is limited to amounts available under our revolving credit facility, amounts outstanding under the program are classified as long-term debt. The commercial paper notes are sold under customary terms in the commercial paper market and are issued at a discount from par, or alternatively, are sold at par and bear varying interest rates on a fixed or floating basis. The weighted-average interest rate for commercial paper borrowings based on the number of days outstanding was 1.3% and 2.3%, respectively, for the year ended December 31, 2017 and 2018.

During the years ending December 31, 2016, 2017 and 2018, total cash payments for interest on all indebtedness, excluding the impact of related interest rate swap agreements, were \$181.7 million, \$206.2 million and \$227.8 million, respectively.

12. Derivative Financial Instruments

We use derivative instruments to manage market price risks associated with inventories, interest rates, tank bottoms and certain forecasted transactions. For those instruments that qualify for hedge accounting, the accounting treatment depends on their intended use and their designation. We divide derivative financial instruments qualifying for hedge accounting treatment into two categories: (1) cash flow hedges and (2) fair value hedges. We execute cash flow hedges to hedge against the variability in cash flows related to a forecasted transaction and execute fair value hedges to hedge against the changes in the value of a recognized asset or liability. At the inception of a hedged transaction, we document the relationship between the hedging instrument and the hedged item, the risk management objectives and the methods used for assessing and testing hedge effectiveness. We also assess, both at the inception of the hedge and on an on-going basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows or fair value of the hedged item. If we determine that a derivative originally designated as a cash flow or fair value hedge is no longer highly effective, we discontinue hedge accounting prospectively and record the change in the fair value of the derivative in current earnings. The changes in fair value of derivative financial instruments that are not designated as hedges for accounting purposes, which we refer to as economic hedges, are included in current earnings.

As part of our risk management process, we assess the creditworthiness of the financial and other institutions with which we execute financial derivatives. Such financial instruments involve the risk of non-performance by the counterparty, which could result in material losses to us.

Our policies prohibit us from engaging in speculative trading activities.

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MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

Interest Rate Derivatives

We periodically enter into interest rate derivatives to hedge the fair value of debt or hedge against variability in interest rates. For interest rate cash flow hedges, we record the noncurrent portion of unrealized gains or losses as an adjustment to other comprehensive income with the current portion recorded as an adjustment to interest expense. For fair value hedges on long-term debt, we record the noncurrent portion of gains or losses as an adjustment to long-term debt with the current portion recorded as an adjustment to interest expense. Adjustments resulting from discontinued hedges continue to be recognized in accordance with their historic hedging relationships.

During 2018, we entered into \$250.0 million of treasury lock agreements to protect against the risk of variability of future interest payments on a portion of debt we anticipate issuing in 2019. The fair values of these contracts at December 31, 2018 were recorded on our balance sheet as other current liabilities of \$8.4 million and other current assets of \$0.3 million, with the net offset recorded to other comprehensive income. We account for these agreements as cash flow hedges.

During 2018, we terminated and settled \$200.0 million of interest rate derivative agreements with cumulative gains of \$24.6 million. These agreements were previously entered into to protect against the risk of variability of future interest payments on debt we anticipated issuing in 2018 or early 2019 and were accounted for as cash flow hedges. The gains were recorded to other comprehensive income and will be recognized into earnings as an adjustment to our periodic interest expense upon issuance of the associated notes. These gains were also reported as a net receipt on financial derivatives in the financing activities of our consolidated statements of cash flows in 2018.

During 2015 and 2016, we entered into \$250.0 million of forward-starting interest rate swap agreements to protect against the risk of variability of future interest payments on a portion of debt we anticipated issuing in 2016. We accounted for these agreements as cash flow hedges. When we issued \$500.0 million of 4.25% notes due 2046 in third quarter 2016, we settled the associated interest rate swap agreements for a cumulative loss of \$19.3 million. The loss was recorded to other comprehensive income and will be recognized into earnings as an adjustment to our periodic interest expense accruals over the first ten years of the associated notes. This loss was also reported as a net payment on financial derivatives in the financing activities of our consolidated statements of cash flows in 2016.

Commodity Derivatives

Our butane blending activities produce gasoline, and we can reasonably estimate the timing and quantities of sales of these products. We use a combination of exchange-based commodities futures contracts and forward purchase and sale contracts to help manage commodity price changes and mitigate the risk of decline in the product margin realized from our butane blending activities. Further, certain of our other commercial operations generate petroleum products, and we also use futures contracts to hedge against price changes for some of these commodities.

Forward physical purchase and sale contracts that qualify for and are elected as normal purchases and sales are accounted for using traditional accrual accounting, whereby changes in the mark-to-market values of such contracts are not recognized in income, rather the revenues and expenses associated with such transactions are recognized during the period when commodities are physically delivered or received. Physical forward commodity contracts subject to this exception are evaluated for the probability of future delivery and are periodically tested once the forecasted period has passed to determine whether similar forward contracts are probable of physical delivery in the

future.

We record the effective portion of the gains or losses for commodity-based contracts designated as fair value hedges as adjustments to the assets being hedged and the ineffective portions as well as amounts excluded from the assessment of hedge effectiveness as adjustments to other income or expense. We recognize the change in fair value of economic hedges that hedge against changes in the price of petroleum products that we expect to sell or purchase

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MAGELLAN MIDSTREAM PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

in the future currently in earnings as adjustments to product sales revenue, cost of product sales, or operating expenses, as applicable.

Our open futures contracts at December 31, 2018 were as follows:

Type of Contract/Accounting Methodology	Product Represented by the Contract and Associated Barrels	Maturity Dates
Futures - Economic Hedges	4.1 million barrels of refined products and crude oil	Between January and June 2019
Futures - Economic Hedges	0.9 million barrels of butane	Between January and April 2019

Energy Commodity Derivatives Contracts and Deposits Offsets

At December 31, 2018, we held margin deposits of \$37.3 million for our futures contracts with our counterparties, which were recorded as a current liability under energy commodity derivatives deposits on our consolidated balance sheets. At December 31, 2017, we had made margin deposits of \$36.7 million for our futures contracts with our counterparties, which were recorded as a current asset under energy commodity derivatives deposits on our consolidated balance sheets. We have the right to offset the combined fair values of our open futures contracts against our margin deposits under a master netting arrangement for each counterparty; however, we have elected to present the combined fair values of our open futures contracts separately from the related margin deposits on our consolidated balance sheets. Additionally, we have the right to offset the fair values of our futures contracts together for each counterparty, which we have elected to do, and we report the combined net balances on our consolidated balance sheets. A schedule of the derivative amounts we have offset and the deposit amounts we could offset under a master netting arrangement are provided below as of December 31, 2017 and 2018 (in thousands):

	Gross Amounts of Recognized Assets (Liabilities)	Gross Amounts of Assets (Liabilities) Offset in the Consolidated Balance Sheets	Net Amounts of Assets (Liabilities) Presented in the Consolidated Balance Sheets ⁽¹⁾	Margin Deposit Amounts Not Offset in the Consolidated Balance Sheets	Net Asset Amount ⁽²⁾
As of December 31, 2017	\$ (38,936)	\$ 12,851	\$ (26,085)	\$ 36,690	\$ 10,605
As of December 31, 2018	\$ 62,166	\$ (7,155)	\$ 55,011	\$ (37,328)	\$ 17,683

(1) Net amount includes energy commodity derivative contracts classified as current liabilities of \$25,694 and noncurrent liabilities of \$391 at December 31, 2017.

(2) Amount represents the maximum loss we would incur if all of our counterparties failed to perform on their derivative contracts.

Impact of Derivatives on Our Financial Statements
Comprehensive Income

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The changes in derivative activity included in AOCL for the years ended December 31, 2016, 2017 and 2018 were as follows (in thousands):

Derivative Gains (Losses) Included in AOCL	Year Ended December 31,		
	2016	2017	2018
Beginning balance	\$(30,126)	\$(34,776)	\$(33,755)
Net gain (loss) on interest rate contract cash flow hedges	(6,699)	(1,937)	4,317
Reclassification of net loss on cash flow hedges to income	2,049	2,958	2,958
Ending balance	\$(34,776)	\$(33,755)	\$(26,480)

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MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

The following is a summary of the effect on our consolidated statements of income for the years ended December 31, 2016, 2017 and 2018 of derivatives that were designated as cash flow hedges (in thousands):

	Interest Rate Contracts		
	Amount of Gain		Amount of Loss
	(Loss)	Location of Loss	Amount of Loss
	Recognized in	Reclassified	Reclassified
	AOCL on	from AOCL into Income	from AOCL into Income
	Derivatives		
Year Ended December 31, 2016	\$ (6,699)	Interest expense	\$ (2,049)
Year Ended December 31, 2017	\$ (1,937)	Interest expense	\$ (2,958)
Year Ended December 31, 2018	\$ 4,317	Interest expense	\$ (2,958)

As of December 31, 2018, the net loss estimated to be classified to interest expense over the next twelve months from AOCL is approximately \$2.2 million. This amount relates to the amortization of losses on interest rate swap contracts over the life of the related debt instruments.

We used futures contracts designated as fair value hedges to hedge against changes in the fair value of crude oil that was contractually reserved as tank bottoms and included with other noncurrent assets on our consolidated balance sheets. During September 2017, as a result of contract renegotiations, we sold a portion of the tank bottoms, settled the related hedges and transferred the permanent portion of the tank bottoms from noncurrent assets to PP&E. The effective portions of the fair value gains or losses on these futures contracts were offset by fair value gains or losses on the crude oil, and there was no ineffectiveness recognized. The cash flows from settled contracts were recorded in operating activities in our consolidated statements of cash flows. The gains (losses) on these futures contracts and the underlying crude oil were as follows (in thousands):

	Year Ended December 31,		
	2016	2017	2018
Gain (loss) recognized in other income/expense on derivative (futures contracts)	\$(8,988)	\$4,806	\$543
Gain (loss) recognized in other income/expense on hedged item (tank bottoms)	\$8,988	\$(4,806)	\$(543)

The differential between the current spot price and forward price was excluded from the assessment of hedge effectiveness for these fair value hedges. During 2016 and 2017, we recognized a gain of \$5.2 million and \$2.4 million, respectively, for the amounts we excluded from the assessment of effectiveness of these fair value hedges, which we reported as other (income) expense on our consolidated statements of income.

MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

The following table provides a summary of the effect on our consolidated statements of income for the years ended December 31, 2016, 2017 and 2018 of derivatives accounted for as economic hedges (in thousands):

Derivative Instrument	Location of Gain (Loss) Recognized on Derivatives	Amount of Gain (Loss) Recognized on Derivative Year Ended December 31,		
		2016	2017	2018
Futures contracts	Product sales revenue	\$(38,584)	\$(56,338)	\$85,012
Futures contracts	Cost of product sales	10,998	25,566	(15,947)
Futures contracts	Operating expenses	(5,000)	3,002	—
	Total	\$(32,586)	\$(27,770)	\$69,065

The impact of the derivatives in the above table was reflected as cash from operations on our consolidated statements of cash flows.

Balance Sheets

The following tables provide a summary of the fair value of derivatives, which are presented on a net basis in our consolidated balance sheets, that were designated as hedging instruments as of December 31, 2017 and 2018 (in thousands):

Derivative Instrument	December 31, 2017		Liability Derivatives	
	Asset Derivatives	Fair Value	Balance Sheet Location	Fair Value
Futures contracts	Energy commodity derivatives contracts, net	\$ —	Energy commodity derivatives contracts, net	\$ 173
Interest rate contracts	Other noncurrent assets	12,177	Other noncurrent liabilities	—
	Total	\$ 12,177	Total	\$ 173

Derivative Instrument	December 31, 2018		Liability Derivatives	
	Asset Derivatives	Fair Value	Balance Sheet Location	Fair Value
Futures contracts	Energy commodity derivatives contracts, net	\$ 462	Energy commodity derivatives contracts, net	\$ —
Interest rate contracts	Other current assets	312	Other current liabilities	8,438
	Total	\$ 774	Total	\$ 8,438

MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

The following tables provide a summary of the fair value of derivatives, which are presented on a net basis in our consolidated balance sheets, that were not designated as hedging instruments as of December 31, 2017 and 2018 (in thousands):

		December 31, 2017			
		Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	
Futures contracts	Energy commodity derivatives contracts, net	\$ 12,605	Energy commodity derivatives contracts, net	\$ 38,126	
Futures contracts	Other noncurrent assets	246	Other noncurrent liabilities	637	
	Total	\$ 12,851	Total	\$ 38,763	
		December 31, 2018			
		Asset Derivatives		Liability Derivatives	
Derivative Instrument	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value	
Futures contracts	Energy commodity derivatives contracts, net	\$ 61,704	Energy commodity derivatives contracts, net	\$ 7,155	

See Note 17 – Fair Value Disclosures for additional details regarding our derivative contracts.

13. Leases

Lessee

We lease office buildings, equipment and pipeline capacity (primarily to facilitate movements on our Longhorn pipeline and Little Rock pipeline extension) and have entered into storage contracts to conduct our business operations. We have also entered into land leases and easement and right-of-way contracts, several of which have cancellation penalties. Several of our agreements provide for negotiated renewal options, and management expects that we will generally renew our expiring leases. Leases are evaluated at inception or at any subsequent material modification and, depending on the lease terms, are classified as either capital or operating leases, as appropriate under ASC 840, Leases. We recognize rent expense on a straight-line basis over the life of the lease. Total rent expense was \$30.2 million, \$34.8 million and \$42.1 million for the years ended December 31, 2016, 2017 and 2018, respectively. Future minimum annual rentals under non-cancellable operating leases and storage contracts with initial or remaining terms greater than one year as of December 31, 2018, were as follows (in millions):

2019	\$33.8
2020	32.3
2021	30.2
2022	27.4
2023	26.7
Thereafter	132.2
Total	\$282.6

MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

The table above includes future minimum annual rentals under our lease with Seabrook for storage capacity at its terminal in Seabrook, Texas. Future minimum payments under this lease are: \$11.0 million in 2019; \$11.0 million in 2020; \$9.4 million in 2021; \$6.6 million in 2022; \$6.6 million in 2023; and \$37.5 million thereafter. Storage and ancillary fees paid to Seabrook, which was included with rent expense, was \$10.6 million in 2018. See Note 5 – Investments in Non-Controlled Entities for further details about this lease.

Lessor

We have entered into capacity leases and storage contracts with our customers with remaining terms from one to approximately 10 years that are accounted for as operating-type leases. All of the agreements provide for negotiated extensions. Future minimum payments receivable under these arrangements that fall under the guidance of ASC 606, Revenues from Contracts with Customers are included in our Unfulfilled Performance Obligations in Note 3 - Revenue. Future minimum payments receivable under these arrangements that fall under the guidance of ASC 840 as of December 31, 2018 are as follows (in millions):

2019	\$39.2
2020	32.8
2021	31.7
2022	22.9
2023	7.2
Thereafter	15.0
Total	\$148.8

During 2017 and 2018, we recognized contingent rental income from our condensate splitter at our Corpus Christi, Texas terminal in the amount of \$24.9 million and \$51.8 million, respectively.

Direct Financing Lease

We entered into a long-term throughput and deficiency agreement with a customer on a 40-mile pipeline we constructed in Texas and New Mexico, which contains minimum volume/payment commitments. This agreement is being accounted for as a direct financing lease. The net investment under direct financing leasing arrangements as of December 31, 2017 and 2018 was as follows (in millions):

	December 31, December 31,	
	2017	2018
Total minimum lease payments receivable	\$ 19.2	\$ 17.5
Less: Unearned income	4.1	3.5
Recorded net investment in direct financing lease	\$ 15.1	\$ 14.0

The net investment in direct financing leases was classified in the consolidated balance sheets as follows (in millions):

	December 31, December 31,	
	2017	2018
Other accounts receivable	\$ 1.1	\$ 1.1
Long-term receivables	14.0	12.9
Total	\$ 15.1	\$ 14.0

MAGELLAN MIDSTREAM PARTNERS, L.P.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

Future minimum payments receivable under this direct financing lease for the next five years are \$1.7 million each year.

14. Long-Term Incentive Plan

The compensation committee of our general partner's board of directors administers our long-term incentive plan ("LTIP") covering certain of our employees and the independent directors of our general partner. The LTIP primarily consists of phantom units and permits the grant of awards covering an aggregate of 11.9 million of our limited partner units. The estimated units remaining available under the LTIP at December 31, 2018 totaled approximately 2.2 million. The awards include: (i) performance-based awards issued to certain officers and other key employees ("performance-based awards"), (ii) time-based awards issued to certain officers and other key employees ("time-based awards," and together with performance-based awards, "employee awards"), and (iii) awards issued to independent members of our general partner's board of directors ("director awards") that may be deferred and if deferred may be paid in cash. All of the awards include distribution equivalent rights, except non-deferred director awards.

The LTIP requires employee awards to be settled in our limited partner units, except the settlement of distribution equivalents, which we pay in cash. As a result, we classify employee awards as equity. Fair value for these awards is determined on the grant date, and we recognize this value as compensation expense ratably over the requisite service period, which is the vesting period of each award. The vesting period for employee awards is generally three years; however, certain awards have been issued with shorter vesting periods while others have vesting periods of up to four years. Because employee awards contain distribution equivalent rights, the fair value of our employee awards is based on the closing price of our units on the grant date.

Payouts for performance-based awards are subject to the attainment of a financial metric and to an adjustment for our total unitholder return (the "TUR adjustment"), and the fair value of these awards is adjusted for the fair value of the TUR adjustment. The financial metric for the performance-based awards is our distributable cash flow per unit excluding commodity-related activities for the last year of the three-year vesting period as compared to established threshold, target and stretch levels. The payouts for the performance-related component of the awards can range from 0% for results below threshold, up to 200% for actual results at stretch or above. The TUR adjustment is based on our total unitholder return at the end of the three-year vesting period of the awards in relation to the total unitholder returns of certain peer entities and can increase or decrease the payout of the award by as much as 50%. Payouts related to time-based awards are based solely on the completion of the requisite service period by the employee and contain no provisions that provide for a payout other than the original number of units awarded and the associated distribution equivalents.

Performance-based awards are subject to forfeiture if a participant's employment is terminated for any reason other than for termination within two years of a change-in-control that occurs on an involuntary basis without cause or on a voluntary basis for good cause, or due to retirement, disability or death prior to the vesting date. These awards can vest early under certain circumstances following a change in control. Time-based awards are subject to forfeiture if a participant's employment is terminated for any reason other than retirement, death or disability prior to the vesting date, or as the result of certain other employment restrictions. If an employee award recipient retires, dies or becomes disabled prior to the end of the vesting period, the award is prorated based upon months of employment completed during the vesting period, and the award is settled shortly after the end of the vesting period.

Compensation expense for our equity awards is calculated as the number of unit awards less forfeitures, multiplied by the grant date fair value of those awards, multiplied by the percentage of the requisite service period completed at each period end, multiplied by the expected payout percentage, less previously-recognized compensation expense.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

Non-deferred director awards are paid in units valued on the grant date, with compensation expense calculated as the number of units awarded multiplied by the fair value of those units at that date. We classify deferred director awards as liability awards because they may be settled in cash. Because deferred director awards have distribution equivalent rights, the fair value of these awards equals the closing price of our units at the measurement date. Compensation expense for deferred director awards is calculated as the number of units awarded, multiplied by the fair value of those awards on the measurement date, less previously-recognized compensation expense. Director awards deferred prior to 2015 are paid in January of the year following the director's resignation from the board of directors of our general partner or death. Director awards deferred after January 1, 2015 are paid 60 days following the director's death or resignation from the board of directors of our general partner.

Non-Vested Unit Awards

The following table includes the changes during the current fiscal year in the number of non-vested units that have been granted by the compensation committee. The amounts below do not include adjustments for above-target or below-target performance.

	Performance-Based Awards		Time-Based Awards		Total Awards	
	Number of Unit Awards	Weighted-Average Fair Value	Number of Unit Awards	Weighted-Average Fair Value	Number of Unit Awards	Weighted-Average Fair Value
Non-vested units - 1/1/2018	356,068	\$ 76.40	61,104	\$ 71.36	417,172	\$ 75.66
Units granted during 2018	218,923	\$ 73.80	83,564	\$ 71.03	302,487	\$ 73.03
Units vested during 2018	(173,718)	\$ 70.30	(31,028)	\$ 64.25	(204,746)	\$ 69.39
Units forfeited during 2018	(11,258)	\$ 76.21	(2,252)	\$ 71.56	(13,510)	\$ 75.44
Non-vested units - 12/31/18	390,015	\$ 77.66	111,388	\$ 73.09	501,403	\$ 76.65

The table below summarizes the total non-vested unit awards outstanding adjusted for estimated amounts of above-target financial performance to determine the total number of unit awards included in our total equity-based liability accrual.

Grant Date	Non-Vested Unit Awards	Adjustment to Unit Awards in Anticipation of Achieving Above-Target Financial Results	Total Unit Award Accrual	Vesting Date	Unrecognized Compensation Expense ^(a) (in millions)
Performance-Based Awards:					
2017 Awards	176,924	159,232	336,156	12/31/2019	\$ 9.0
2018 Awards	213,091	—	213,091	12/31/2020	10.5
Time-Based Awards:					
2019 Vesting Date	31,835	—	31,835	12/31/2019	0.9

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2020 Vesting Date	79,553	—	79,553	12/31/2020	3.9
Total	501,403	159,232	660,635		\$ 24.3

(a) Unrecognized compensation expense will be recognized over the remaining vesting period of the awards.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

Weighted-Average Fair Value

The weighted-average fair value of awards granted during 2016, 2017 and 2018 was as follows:

	Performance-Based Awards		Time-Based Awards	
	Number	Weighted-Average	Number	Weighted-Average
	of	Fair Value	of	Fair Value
	Unit	Awards	Unit	Awards
Units granted during 2016	193,344	\$ 70.29	39,301	\$ 64.76
Units granted during 2017	189,544	\$ 82.34	30,604	\$ 79.10
Units granted during 2018	218,923	\$ 73.80	83,564	\$ 71.03

Vested Unit Awards

The table below sets forth the numbers and values of units that vested in each of the three years ended December 31, 2018. The vested limited partner units include adjustments for above-target financial and market performance.

Vesting Date	Vested Limited Partner Units	Fair Value of Unit Awards on Vesting Date (in millions)	Intrinsic Value of Unit Awards on Vesting Date (in millions)
12/31/2016	361,711	\$22.6	\$27.4
12/31/2017	266,028	\$19.9	\$18.9
12/31/2018	317,037	\$22.1	\$18.1

Cash Flow Effects of LTIP Settlements

The difference between the limited partner units issued to the participants and the total number of unit awards vested primarily represents the tax withholdings associated with the award settlement, which we pay in cash.

Settlement Date	Number of Limited Partner Units Issued, Net of Tax Withholdings	Tax Withholdings and Other Cash Payments (in millions)	Employer Taxes (in millions)	Total Cash Payments (in millions)
February 2016	350,552	\$14.4	\$1.4	\$15.8
January 2017	216,679	\$13.9	\$1.2	\$15.1
January 2018	168,913	\$9.3	\$1.1	\$10.4

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

Compensation Expense Summary

Equity-based incentive compensation expense for 2016, 2017 and 2018 was as follows (in thousands):

	Year Ended December 31,		
	2016	2017	2018
Performance awards	\$17,106	\$17,823	\$28,728
Time-based awards	2,252	2,818	3,325
Total	\$19,358	\$20,641	\$32,053

Allocation of LTIP
expense on our
consolidated
statements of
income:

G&A expense	\$19,204	\$20,463	\$31,788
Operating expense	154	178	265
Total	\$19,358	\$20,641	\$32,053

15. Segment Disclosures

Our reportable segments are strategic business units that offer different products and services. Our segments are managed separately because each segment requires different marketing strategies and business knowledge. Management evaluates performance based on segment operating margin, which includes revenue from affiliates and external customers, operating expenses, cost of product sales and earnings of non-controlled entities.

We believe that investors benefit from having access to the same financial measures used by management. Operating margin, which is presented in the following tables, is an important measure used by management to evaluate the economic performance of our core operations. Operating margin is not a GAAP measure, but the components of operating margin are computed using amounts that are determined in accordance with GAAP. A reconciliation of operating margin to operating profit, which is its nearest comparable GAAP financial measure, is included in the tables below. Operating profit includes depreciation, amortization and impairment expense and G&A expense that management does not consider when evaluating the core profitability of our separate operating segments.

During 2018, we adopted ASC 606, Revenue from Contracts with Customers. Prior year amounts reflected in the following tables have not been adjusted and continue to be reflected in accordance with our historical accounting. Refer to Note 2 – Summary of Significant Accounting Policies for further details.

MAGELLAN MIDSTREAM PARTNERS, L.P.
 NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

	Year Ended December 31, 2016				
	(in thousands)				
	Refined Products	Crude Oil	Marine Storage	Intersegment Eliminations	Total
Transportation and terminals revenue	\$1,002,368	\$407,837	\$181,721	\$ (807)	\$1,591,119
Product sales revenue	561,759	31,170	6,673	—	599,602
Affiliate management fee revenue	765	12,533	1,391	—	14,689
Total revenue	1,564,892	451,540	189,785	(807)	2,205,410
Operating expenses	380,347	88,528	65,559	(5,762)	528,672
Cost of product sales	459,989	31,657	1,692	—	493,338
(Earnings) losses of non-controlled entities	968	(76,972)	(2,692)	—	(78,696)
Operating margin	723,588	408,327	125,226	4,955	1,262,096
Depreciation, amortization and impairment expense	103,388	38,081	31,718	4,955	178,142
G&A expenses	91,372	36,165	19,628	—	147,165
Operating profit	\$528,828	\$334,081	\$73,880	\$ —	\$936,789
Additions to long-lived assets	\$291,202	\$250,433	\$104,728		\$646,363
	As of December 31, 2016				
Segment assets	\$3,289,600	\$2,631,407	\$791,132		\$6,712,139
Corporate assets					59,934
Total assets					\$6,772,073
Goodwill	\$38,369	\$12,082	\$2,809		\$53,260
Investments in non-controlled entities	\$31,029	\$886,920	\$13,306		\$931,255

MAGELLAN MIDSTREAM PARTNERS, L.P.
 NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

	Year Ended December 31, 2017				
	(in thousands)				
	Refined Products	Crude Oil	Marine Storage	Intersegment Eliminations	Total
Transportation and terminals revenue	\$1,096,040	\$458,455	\$180,683	\$ (3,403)	\$1,731,775
Product sales revenue	717,140	35,053	6,013	—	758,206
Affiliate management fee revenue	1,388	13,950	2,342	—	17,680
Total revenue	1,814,568	507,458	189,038	(3,403)	2,507,661
Operating expenses	400,439	120,920	65,296	(8,677)	577,978
Cost of product sales	586,751	41,325	7,541	—	635,617
(Earnings) losses of non-controlled entities	1,632	(120,173)	(2,453)	—	(120,994)
Operating margin	825,746	465,386	118,654	5,274	1,415,060
Depreciation, amortization and impairment expense	109,434	48,796	33,126	5,274	196,630
G&A expenses	103,225	41,490	21,002	—	165,717
Operating profit	\$613,087	\$375,100	\$64,526	\$ —	\$1,052,713
Additions to long-lived assets	\$269,369	\$168,306	\$127,012		\$564,687
	As of December 31, 2017				
Segment assets	\$3,499,492	\$2,817,186	\$871,557		\$7,188,235
Corporate assets					206,140
Total assets					\$7,394,375
Goodwill	\$38,369	\$12,082	\$2,809		\$53,260
Investments in non-controlled entities	\$29,578	\$961,032	\$91,901		\$1,082,511

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

	Year Ended December 31, 2018				
	(in thousands)				
	Refined Products	Crude Oil	Marine Storage	Intersegment Eliminations	Total
Transportation and terminals revenue	\$1,151,980	\$549,849	\$180,850	\$ (3,691)	\$1,878,988
Product sales revenue	872,144	46,767	8,309	—	927,220
Affiliate management fee revenue	1,512	14,832	4,021	—	20,365
Total revenue	2,025,636	611,448	193,180	(3,691)	2,826,573
Operating expenses	424,851	166,213	68,010	(9,638)	649,436
Cost of product sales	650,071	44,128	10,114	—	704,313
Earnings of non-controlled entities	(16,039)	(162,233)	(2,845)	—	(181,117)
Operating margin	966,753	563,340	117,901	5,947	1,653,941
Depreciation, amortization and impairment expense	168,954	54,318	35,858	5,947	265,077
G&A expenses	118,491	51,523	24,269	—	194,283
Operating profit	\$679,308	\$457,499	\$57,774	\$ —	\$1,194,581
Additions to long-lived assets	\$298,502	\$142,108	\$65,744		\$506,354
	As of December 31, 2018				
Segment assets	\$3,715,653	\$2,710,068	\$1,065,525		\$7,491,246
Corporate assets					256,291
Total assets					\$7,747,537
Goodwill	\$38,369	\$12,082	\$2,809		\$53,260
Investments in non-controlled entities	\$37,574	\$783,486	\$255,246		\$1,076,306

16. Commitments and Contingencies

Certain conditions may exist as of the date our consolidated financial statements are issued that could result in a loss to us, but which will only be resolved when one or more future events occur or fail to occur. Our management assesses such contingent liabilities, which inherently involves significant judgment. In assessing loss contingencies related to legal proceedings that are pending against us or for unasserted claims that may result in proceedings, our management, with input from legal counsel, evaluates the perceived merits of any legal proceedings or unasserted claims as well as the perceived merits of the amount of relief sought or expected to be sought therein.

Environmental expenditures are charged to operating expense or capitalized based on the nature of the expenditures. Environmental expenditures that meet the capitalization criteria for property, plant and equipment, as well as costs that mitigate or prevent environmental contamination that has yet to occur, are capitalized. We expense expenditures that relate to an existing condition caused by past operations. We initially record environmental liabilities assumed in a business combination at fair value; otherwise, we record environmental liabilities on an undiscounted basis. We recognize liabilities for other commitments and contingencies when, after analyzing the available information, we determine it is probable that an asset has been impaired, or that a liability has been incurred and the amount of impairment or loss can be reasonably estimated. When we can estimate a range of probable loss, we accrue the most likely amount within that range, or if no amount is more likely than another, we accrue the minimum of the range of probable loss. We expense legal costs associated with loss contingencies as incurred.

We record environmental liabilities independently of any potential claim for recovery. Accruals related to environmental matters are generally determined based on site-specific plans for remediation, taking into account

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

currently available facts, existing technologies and presently enacted laws and regulations. Accruals for environmental matters reflect our prior remediation experience and include an estimate for costs such as fees paid to contractors, outside engineering and consulting firms. Accruals for estimated losses from environmental remediation obligations generally are recognized no later than completion of the remediation feasibility study. Such accruals are adjusted as further information develops or circumstances change.

We maintain specific insurance coverage, which may cover all or portions of certain environmental expenditures less a deductible. We recognize receivables in cases where we consider the realization of reimbursements of remediation costs as probable. We would sustain losses to the extent of amounts we have recognized as environmental receivables if the counterparties to those transactions were unable to perform their obligations to us.

The determination of the accrual amounts recorded for environmental liabilities includes significant judgments and assumptions made by management. The use of alternate judgments and assumptions could result in the recognition of different levels of environmental remediation costs.

Butane Blending Patent Infringement Proceeding

On October 4, 2017, Sunoco Partners Marketing & Terminals L.P. (“Sunoco”) brought an action for patent infringement in the U.S. District Court for the District of Delaware alleging Magellan Midstream Partners, L.P. (“Magellan”) and Powder Springs Logistics, LLC (“Powder Springs”) have infringed patents relating to butane blending at the Powder Springs facility located in Powder Springs, Georgia. Sunoco has since submitted pleadings alleging that Magellan has also infringed various patents relating to butane blending at nine Magellan facilities, in addition to Powder Springs. Sunoco is seeking an undetermined amount of damages, attorneys’ fees and a permanent injunction enjoining Magellan and Powder Springs from infringing on the subject patents. We deny and are vigorously defending against all claims asserted by Sunoco. Although it is not possible to predict the ultimate outcome, we believe, based on our current understanding of the applicable facts and law, that the ultimate resolution of this matter will not have a material adverse impact on our results of operations, financial position or cash flows.

Environmental Liabilities

Liabilities recognized for estimated environmental costs were \$19.3 million and \$20.5 million at December 31, 2017 and December 31, 2018, respectively. We have classified environmental liabilities as current or noncurrent based on management’s estimates regarding the timing of actual payments. Environmental expenses recognized as a result of changes in our environmental liabilities are included in operating expenses on our consolidated statements of income. Environmental expenses were \$5.9 million, \$9.0 million and \$15.0 million for the years ended December 31, 2016, 2017 and 2018, respectively.

Environmental Receivables

Receivables from insurance carriers and other third parties related to environmental matters at December 31, 2017 were \$7.2 million, of which \$0.5 million and \$6.7 million were recorded to other accounts receivable and long-term receivables, respectively, on our consolidated balance sheets. Receivables from insurance carriers related to environmental matters at December 31, 2018 were \$4.1 million, of which \$2.4 million and \$1.7 million were recorded to other accounts receivable and long-term receivables, respectively, on our consolidated balance sheets. Amounts

received from insurance carriers and other third parties related to environmental matters during 2016, 2017 and 2018 were \$0.9 million, \$0.7 million and \$3.1 million, respectively.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

Other

In connection with the sale of part of our interest in BridgeTex (see Note 5 – Investments in Non-Controlled Entities), we agreed to indemnify an affiliate of OMERS for certain claims involving BridgeTex. The maximum obligation is limited to the net proceeds we received. We probability-weighted potential outcome scenarios to estimate the value of such indemnification obligations. As a result, we reduced the gain recognized on the transaction by \$16.0 million and recorded the same estimate in other noncurrent liabilities on our consolidated balance sheets this period as a Level 3 measurement.

We have entered into an agreement to guarantee our 50% pro rata share, up to \$25.0 million, of obligations under Powder Springs' credit facility. As of December 31, 2018, our consolidated balance sheets reflected a \$0.4 million other current liability and a corresponding increase in our investment in non-controlled entities to reflect the fair value of this guarantee.

We are a party to various other claims, legal actions and complaints arising in the ordinary course of business, including without limitation those disclosed in Item 3. Legal Proceedings of Part I of this annual report on Form 10-K. While the results cannot be predicted with certainty, management believes the ultimate resolution of these claims, legal actions and complaints after consideration of amounts accrued, insurance coverage or other indemnification arrangements will not have a material adverse effect on our results of operations, financial position or cash flows.

17. Fair Value Disclosures

Fair Value Methods and Assumptions - Financial Assets and Liabilities

The following methods and assumptions were used in estimating fair value for our financial assets and liabilities:

Energy commodity derivatives contracts. These include exchange-traded futures contracts related to petroleum products. These contracts are carried at fair value on our consolidated balance sheets and are valued based on quoted prices in active markets. See Note 12 – Derivative Financial Instruments for further disclosures regarding these contracts.

Interest rate contracts. These include forward-starting interest rate swap agreements to hedge against the risk of variability of interest payments on future debt. These contracts are carried at fair value on our consolidated balance sheets and are valued based on an assumed exchange, at the end of each period, in an orderly transaction with a market participant in the market in which the financial instrument is traded. The exchange value was calculated using present value techniques on estimated future cash flows based on forward interest rate curves. See Note 12 – Derivative Financial Instruments for further disclosures regarding these contracts.

Long-term receivables. These primarily include payments receivable under a direct-financing leasing arrangement and cost reimbursement payments receivable. These receivables were recorded at fair value on our consolidated balance sheets, using then-current market rates to estimate the present value of future cash flows.

Guarantees. These primarily include an indemnity agreement we entered into with OMERS in connection with the partial sale of our interest in BridgeTex. These guarantees were recorded at fair value on our consolidated balance

sheets upon initial recognition, using probability-weighted potential outcome scenarios to estimate the value of such guarantees.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

Debt. The fair value of our publicly traded notes was based on the prices of those notes at December 31, 2017 and 2018; however, where recent observable market trades were not available, prices were determined using adjustments to the last traded value for that debt issuance or by adjustments to the prices of similar debt instruments of peer entities that are actively traded. The carrying amount of borrowings, if any, under our revolving credit facility and our commercial paper program approximates fair value due to the frequent repricing of these obligations.

Fair Value Measurements - Financial Assets and Liabilities

The following tables summarize the carrying amounts, fair values and fair value measurements recorded or disclosed as of December 31, 2017 and 2018, based on the three levels established by ASC 820; Fair Value Measurements and Disclosures (in thousands):

Assets (Liabilities)	Carrying Amount	Fair Value	Fair Value Measurements as of December 31, 2017 using:		
			Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Energy commodity derivatives contracts	\$(26,085)	\$(26,085)	\$(26,085)	\$—	\$ —
Interest rate contracts	\$12,177	\$12,177	\$—	\$12,177	\$ —
Long-term receivables	\$27,676	\$27,676	\$—	\$—	\$ 27,676
Debt	\$(4,524,492)	\$(4,826,480)	\$—	\$(4,826,480)	\$ —

Assets (Liabilities)	Carrying Amount	Fair Value	Fair Value Measurements as of December 31, 2018 using:		
			Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Energy commodity derivatives contracts	\$55,011	\$55,011	\$55,011	\$—	\$ —
Interest rate contracts	\$(8,126)	\$(8,126)	\$—	\$(8,126)	\$ —
Long-term receivables	\$20,844	\$20,844	\$—	\$—	\$ 20,844
Guarantees	\$(16,409)	\$(16,409)	\$—	\$—	\$(16,409)
Debt	\$(4,270,869)	\$(4,224,373)	\$—	\$(4,224,373)	\$ —

18. Partners' Capital and Distributions

Partners' Capital

In May 2017, we filed a prospectus supplement to the shelf registration statement for our continuous equity offering program (which we refer to as an at-the-market program, or “ATM”) pursuant to which we may issue up to \$750.0 million of common units in amounts, at prices and on terms to be determined by market conditions at the time. The net proceeds from any sales under the ATM, after deducting the sales agents’ commissions and our offering expenses, will be used for general partnership purposes, including repayment of indebtedness or capital expenditures. No units were issued pursuant to this program during 2017 or 2018.

MAGELLAN MIDSTREAM PARTNERS, L.P.
 NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

The following table details the changes in the number of our limited partner units outstanding from January 1, 2016 through December 31, 2018:

Limited partner units outstanding on January 1, 2016	227,427,247
February 2016—Settlement of employee LTIP awards	350,552
During 2016—Other	6,117
Limited partner units outstanding on December 31, 2016	227,783,916
January 2017—Settlement of employee LTIP awards	216,679
During 2017—Other	23,961
Limited partner units outstanding on December 31, 2017	228,024,556
January 2018—Settlement of employee LTIP awards	168,913
During 2018—Other	1,691
Limited partner units outstanding on December 31, 2018	228,195,160

(a) Limited partner units issued to settle the equity-based retainer paid to independent directors of our general partner.

Our partnership agreement allows us to issue additional partnership securities for any partnership purpose at any time and from time to time for consideration and on terms and conditions as our general partner determines, all without approval by the limited partners.

Limited partners holding our limited partner units have the following rights, among others:

- right to receive distributions of our available cash within 45 days after the end of each quarter;
- right to elect the board members of our general partner;
- right to remove Magellan GP, LLC as our general partner upon a 100% vote of outstanding unitholders;
- right to transfer limited partner unit ownership to substitute limited partners;
- right to receive an annual report, containing audited financial statements and a report on those financial statements by our independent public accountants, within 120 days after the close of the fiscal year end;
- right to receive information reasonably required for tax reporting purposes within 90 days after the close of the calendar year;
- right to vote according to the limited partners' percentage interest in us at any meeting that may be called by our general partner; and
- right to inspect our books and records at the unitholders' own expense.

In the event of liquidation, we would distribute all property and cash in excess of that required to discharge all liabilities to the partners in proportion to the positive balances in their respective capital accounts. The limited partners' liability is generally limited to their investment.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

Distributions

Distributions we paid during 2016, 2017 and 2018 were as follows (in thousands, except per unit amount):

Payment Date	Per Unit	
	Cash Distribution Amount	Total Cash Distribution
2/12/2016	\$ 0.7850	\$ 178,808
5/13/2016	0.8025	182,797
8/12/2016	0.8200	186,783
11/14/2016	0.8375	190,769
Total	\$ 3.2450	\$ 739,157
2/14/2017	\$ 0.8550	\$ 194,961
5/15/2017	0.8725	198,951
8/14/2017	0.8900	202,942
11/14/2017	0.9050	206,362
Total	\$ 3.5225	\$ 803,216
2/14/2018	\$ 0.9200	\$ 209,940
5/15/2018	0.9375	213,933
8/14/2018	0.9575	218,497
11/14/2018	0.9775	223,061
Total	\$ 3.7925	\$ 865,431

19. Subsequent Events

Recognizable events

No recognizable events have occurred subsequent to December 31, 2018.

Non-recognizable events

On January 18, 2019, we issued \$500.0 million of 4.85% senior notes due 2049 in an underwritten public offering. The notes were issued at 99.371% of par. Net proceeds from this offering were approximately \$492.5 million after underwriting discounts. The net proceeds from this offering along with cash on hand were used to redeem our 6.55% senior notes due 2019, which were paid on February 11, 2019.

On February 1, 2019, we issued 208,268 limited partner units, of which 199,792 were issued to settle unit awards to certain employees that vested on December 31, 2018 and 8,476 were issued to settle the equity-based retainers paid to four independent directors of our general partner.

On February 1, 2019, 347,473 unit awards were granted pursuant to our LTIP. These awards included both performance-based and time-based awards and have a three-year vesting period that will end on December 31, 2021.

On February 14, 2019, we paid cash distributions of \$0.9975 per unit on our outstanding limited partner units to unitholders of record at the close of business on February 7, 2019. The total distributions paid were \$227.8 million.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—Continued

Our collective bargaining agreement with approximately 24% of the employees assigned to our refined products segment that are represented by the USW expired in January 2019. We are operating under a 24-hour rolling extension of this agreement while negotiations for a new agreement continue.

Quarterly Financial Data (unaudited)

Summarized quarterly financial data is as follows (in thousands, except per unit amounts):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2017				
Revenue	\$642,074	\$619,440	\$572,848	\$673,299
Total costs and expenses	\$392,047	\$383,558	\$374,298	\$426,039
Operating margin	\$359,052	\$353,747	\$316,812	\$385,449
Net income	\$222,736	\$210,400	\$198,500	\$237,895
Basic net income per limited partner unit	\$0.98	\$0.92	\$0.87	\$1.04
Diluted net income per limited partner unit	\$0.98	\$0.92	\$0.87	\$1.04
2018				
Revenue	\$678,779	\$644,091	\$638,020	\$865,683
Total costs and expenses	\$441,323	\$420,433	\$396,242	\$555,111
Operating margin	\$370,429	\$373,077	\$399,190	\$511,245
Net income	\$210,910	\$214,409	\$594,534	\$314,072
Basic net income per limited partner unit	\$0.92	\$0.94	\$2.60	\$1.38
Diluted net income per limited partner unit	\$0.92	\$0.94	\$2.60	\$1.37

In fourth quarter 2018, we made the decision to discontinue commercial operations of our ammonia pipeline beginning in late 2019 due to the system's low profitability and challenging economic outlook. As a result, we recognized a \$49.1 million impairment charge, which impacted total costs and expenses and net income on our consolidated statements of income.

In third quarter 2018, we sold a 20% interest in BridgeTex to an affiliate of OMERS Infrastructure Management Inc., which reduced our ongoing ownership in BridgeTex to a 30% interest. We received \$575.6 million in cash from the sale and recognized a gain of \$353.8 million that impacted net income on our consolidated statements of income.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure
None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

We performed an evaluation of the effectiveness of the design and operation of our “disclosure controls and procedures” (as defined in Rule 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the “Exchange Act”)) as of the end of the period covered by this report. We performed this evaluation under the supervision and with the participation of our management, including our general partner’s Chief Executive Officer (“CEO”) and Chief Financial Officer (“CFO”). Based upon that evaluation, our general partner’s CEO and CFO concluded that, as of the end of the period covered by this report, our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission’s rules and forms. Our disclosure controls and procedures include controls and procedures designed so that information required to be disclosed in reports filed or submitted under the Exchange Act is accumulated and communicated to management, including the CEO and the CFO, as appropriate, to allow timely decisions regarding required disclosure. There has been no change in our internal control over financial reporting that occurred during the quarter ended December 31, 2018 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Management’s Report on Internal Control Over Financial Reporting

See “Management’s Annual Report on Internal Control Over Financial Reporting” set forth in Item 8. Financial Statements and Supplementary Data.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information regarding the directors and executive officers of our general partner and our corporate governance required by Items 401, 405, 406 and 407(c)(3), (d)(4) and (d)(5) of Regulation S-K will be presented in our definitive proxy statement to be filed pursuant to Regulation 14A (our “Proxy Statement”) under the following captions, which information is to be incorporated by reference herein:

- Director Election Proposal;
- Executive Officers of our General Partner;
- Section 16(a) Beneficial Ownership Reporting Compliance;
- Code of Ethics;
- Corporate Governance – Director Nominations; and
- Corporate Governance – Board Committees.

Item 11. Executive Compensation

The information regarding executive compensation required by Items 402 and 407(e)(4) and (e)(5) of Regulation S-K will be presented in our Proxy Statement under the following captions, which information is to be incorporated by reference herein:

- Compensation of Directors and Executive Officers;
- Compensation Committee Interlocks and Insider Participation; and
- Compensation of Directors and Executive Officers – Compensation Committee Report.

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

The information regarding securities authorized for issuance under equity compensation plans and security ownership required by Items 201(d) and 403 of Regulation S-K will be presented in our Proxy Statement under the following captions, which information is to be incorporated by reference herein:

- Securities Authorized for Issuance Under Equity Compensation Plans; and
- Security Ownership of Certain Beneficial Owners and Management.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information regarding certain relationships and related transactions and director independence required by Items 404 and 407(a) of Regulation S-K will be presented in our Proxy Statement under the following captions, which information is to be incorporated by reference herein:

- Transactions with Related Persons, Promoters and Certain Control Persons; and
- Corporate Governance – Director Independence.

Item 14. Principal Accountant Fees and Services

The information regarding principal accountant fees and services required by Item 9(e) of Schedule 14A of the Exchange Act will be presented in our Proxy Statement under the caption “Ratification of Appointment of Independent Auditor Proposal,” which information is to be incorporated by reference herein.

PART IV

Item 15. Exhibits and Financial Statement Schedules
(a)1 and (a)2.

	Page
Covered by reports of independent auditors:	
<u>Consolidated statements of income for the three years ended December 31, 2018</u>	<u>72</u>
<u>Consolidated statements of comprehensive income for the three years ended December 31, 2018</u>	<u>73</u>
<u>Consolidated balance sheets at December 31, 2017 and 2018</u>	<u>74</u>
<u>Consolidated statements of cash flows for the three years ended December 31, 2018</u>	<u>75</u>
<u>Consolidated statement of partners' capital for the three years ended December 31, 2018</u>	<u>76</u>
<u>Notes 1 through 19 to consolidated financial statements</u>	<u>77</u>
Not covered by reports of independent auditors:	
<u>Quarterly financial data (unaudited)</u>	<u>121</u>
We have omitted all other required schedules since the required information is not present or is not present in amounts sufficient to require submission of the schedule, or because the information required is included in the financial statements and notes thereto.	

(a)3, (b) and (c). The exhibits listed below on the Index to Exhibits are filed or incorporated by reference as part of this annual report.

Index to Exhibits

Exhibit No. Description

Exhibit 3

- *(a) Certificate of Limited Partnership of Magellan Midstream Partners, L.P. dated August 30, 2000, as amended on November 15, 2002 and August 12, 2003 (filed as Exhibit 3.1 to Form 10-Q filed November 10, 2003).
- *(b) Fifth Amended and Restated Agreement of Limited Partnership of Magellan Midstream Partners, L.P. dated September 28, 2009 (filed as Exhibit 3.1 to Form 8-K filed September 30, 2009).
- *(c) Amendment No. 1 dated October 27, 2011 to Fifth Amended and Restated Agreement of Limited Partnership of Magellan Midstream Partners, L.P. dated September 28, 2009 (filed as Exhibit 3.1 to Form 8-K filed October 28, 2011).
- *(d) Amendment No. 2 dated January 16, 2017 to Fifth Amended and Restated Agreement of Limited Partnership of Magellan Midstream Partners, L.P. dated September 28, 2009 (filed as Exhibit 3.2 to Form 8-K filed January 17, 2017).
- *(e) Amendment No. 3 dated October 25, 2018 to Fifth Amended and Restated Agreement of Limited Partnership of Magellan Midstream Partners, L.P. dated September 28, 2009 (filed as Exhibit 3.1 to Form 8-K filed October 26, 2018).
- *(f) Amended and Restated Certificate of Formation of Magellan GP, LLC dated November 15, 2002, as amended on August 12, 2003 (filed as Exhibit 3(f) to Form 10-K filed March 10, 2004).
- *(g) Third Amended and Restated Limited Liability Company Agreement of Magellan GP, LLC dated September 28, 2009 (filed as Exhibit 3.2 to Form 8-K filed September 30, 2009).
- *(h) Amendment No. 1 dated January 16, 2017 to Third Amended and Restated Limited Liability Company Agreement of Magellan GP, LLC dated September 28, 2009 (filed as Exhibit 3.1 to Form 8-K filed January 17, 2017).

Exhibit 4

- *(a) Indenture dated as of April 19, 2007 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to Form 8-K filed April 20, 2007).
- *(b) First Supplemental Indenture dated as of April 19, 2007 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to Form 8-K filed April 20, 2007).
- *(c) Third Supplemental Indenture dated as of June 26, 2009 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to Form 8-K filed June 26, 2009).
- *(d) Indenture dated as of August 11, 2010 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to Form 8-K filed August 16, 2010).
- *(e) First Supplemental Indenture dated as of August 11, 2010 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to Form 8-K filed August 16, 2010).

- * (f) Second Supplemental Indenture dated as of November 9, 2012 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to Form 8-K filed November 9, 2012).
- * (g) Third Supplemental Indenture dated as of October 10, 2013 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to Form 8-K filed October 10, 2013).
- * (h) Fourth Supplemental Indenture dated as of March 4, 2015 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to Form 8-K filed March 4, 2015).
- * (i) Fifth Supplemental Indenture dated as of March 4, 2015 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.3 to Form 8-K filed March 4, 2015).
- * (j) Sixth Supplemental Indenture dated as of February 29, 2016 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to Form 8-K filed February 29, 2016).
- * (k) Seventh Supplemental Indenture dated as of September 13, 2016 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to Form 8-K filed September 13, 2016).
- * (l) Eighth Supplemental Indenture dated as of October 3, 2017 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to Form 8-K filed October 3, 2017).
- * (m) Ninth Supplemental Indenture dated as of January 18, 2019 between Magellan Midstream Partners, L.P. and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to Form 8-K filed January 18, 2019).

Exhibit 10

- * (a) Amended and Restated Magellan Midstream Partners Long-Term Incentive Plan dated January 26, 2016 (filed as Exhibit 10(a) to Form 10-K filed February 19, 2016).
- (b) Description of Magellan 2019 Annual Incentive Program.
- (c) Magellan GP, LLC Non-Management Director Compensation Program effective January 1, 2019.

Exhibit No.	Description
* (d)	<u>Amended and Restated Director Deferred Compensation Plan effective January 28, 2014 (filed as Exhibit 10(d) to Form 10-K filed February 24, 2014).</u>
* (e)	<u>\$1,000,000,000 Second Amended and Restated Credit Agreement dated as of October 26, 2017 among Magellan Midstream Partners, L.P., the Lenders party thereto, Wells Fargo Bank, National Association, as Administrative Agent and an Issuing Bank, JPMorgan Chase Bank, N.A., as Co-Syndication Agent and an Issuing Bank, and SunTrust Bank, as Co-Syndication Agent and an Issuing Bank (filed as Exhibit 10.1 to Form 8-K filed October 27, 2017).</u>
* (f)	<u>Executive Severance Pay Plan dated July 21, 2011 (filed as Exhibit 10.2 to Form 10-Q filed August 4, 2011).</u>
(g)	<u>Form of 2019 Performance Based Phantom Unit Agreement for awards granted pursuant to the Magellan Midstream Partners Long-Term Incentive Plan.</u>
(h)	<u>Form of 2019 Retention Phantom Unit Agreement for awards granted pursuant to the Magellan Midstream Partners Long-Term Incentive Plan.</u>
* (i)	<u>Form of Commercial Paper Dealer Agreement between Magellan Midstream Partners, L.P., as Issuer, and the Dealer party thereto (filed as Exhibit 10.1 to Form 8-K filed April 22, 2014).</u>
* (j)	<u>Form of Indemnification Agreement by and among Magellan Midstream Partners, L.P., Magellan GP, LLC and the directors and officers of Magellan GP, LLC (filed as Exhibit 10.1 to Form 10-Q filed November 3, 2015).</u>
Exhibit 14	
* (a)	<u>Code of Ethics dated February 1, 2011 by Michael N. Mears, principal executive officer (filed as Exhibit 14(a) to Form 10-K filed February 25, 2011).</u>
* (b)	<u>Code of Ethics dated May 18, 2015 by Aaron L. Milford, principal financial and accounting officer (filed as Exhibit 14(b) to Form 10-K filed February 19, 2016).</u>
Exhibit 21	<u>Subsidiaries of Magellan Midstream Partners, L.P.</u>
Exhibit 23	<u>Consent of Independent Registered Public Accounting Firm.</u>
Exhibit 31	
(a)	<u>Certification of Michael N. Mears, principal executive officer.</u>
(b)	<u>Certification of Aaron L. Milford, principal financial officer.</u>
Exhibit 32	
(a)	<u>Section 1350 Certification of Michael N. Mears, Chief Executive Officer.</u>

(b) Section 1350 Certification of Aaron L. Milford, Chief Financial Officer.

Exhibit
101.INS XBRL Instance Document.

Exhibit
101.SCH XBRL Taxonomy Extension Schema.

Exhibit
101.CAL XBRL Taxonomy Extension Calculation Linkbase.

Exhibit
101.DEF XBRL Taxonomy Extension Definition Linkbase.

Exhibit
101.LAB XBRL Taxonomy Extension Label Linkbase.

Exhibit
101.PRE XBRL Taxonomy Extension Presentation Linkbase.

* Each such exhibit has heretofore been filed with the Securities and Exchange Commission as part of the filing indicated and is incorporated herein by reference.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

MAGELLAN MIDSTREAM PARTNERS, L.P.
(Registrant)

By: MAGELLAN GP, LLC, its general partner

By: /s/ AARON L. MILFORD
Aaron L. Milford
Senior Vice President
and Chief Financial Officer

Date: February 15, 2019

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacity and on the dates indicated.

Signature	Title	Date
/s/ MICHAEL N. MEARS Michael N. Mears	Chairman of the Board and Principal Executive Officer of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 15, 2019
/s/ AARON L. MILFORD Aaron L. Milford	Principal Financial and Accounting Officer of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 15, 2019
/s/ WALTER R. ARNHEIM Walter R. Arnheim	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 15, 2019
/s/ ROBERT G. CROYLE Robert G. Croyle	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 15, 2019
/s/ LORI A GOBILLOT Lori A Gobillot	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 15, 2019
/s/ EDWARD J. GUAY Edward J. Guay	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 15, 2019
/s/ STACY P. METHVIN Stacy P. Methvin	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 15, 2019
/s/ JAMES R. MONTAGUE James R. Montague	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 15, 2019
/s/ BARRY R. PEARL Barry R. Pearl	Director of Magellan GP, LLC, General Partner of Magellan Midstream Partners, L.P.	February 15, 2019